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

Response to Comments

EPA United States Environmental Protection Agency

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U.S. Environmental Protection Agency

United States Environmental Protection Agency

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List of Acronyms and Abbreviations

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

ACE	*Americans for Clean Energy v. EPA*, 864 F.3d 691 (D.C. Cir. 2017)
AEO	Annual Energy Outlook
API	*API v. EPA*, 706 F.3d 474 (D.C. Cir. 2013)
ATJ	Alcohol-to-jet
BBD	Biomass-Based Diesel
BIP	Biofuels Infrastructure Partnership
BOB	Gasoline Before Oxygenate Blending
BRR	Biogas Regulatory Reform
CAA	Clean Air Act
CBI	Confidential Business Information
CBD	*Center for Biological Diversity v. EPA*, 141 F.4th 153 (D.C. Cir. 2025)
CKF	Corn Kernel Fiber
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CWC	Cellulosic Waiver Credits
DCO	Distillers Corn Oil
DGE	Diesel-Gallon Equivalent
DOE	U.S. Department of Energy
DRIA	Draft Regulatory Impact Analysis
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EPA	U.S. Environmental Protection Agency
FFV	Flexible Fuel Vehicle
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
HBIIP	Higher Blends Infrastructure Incentive Program
IRR	Import RIN Reduction
LCA	Lifecycle Analysis
LCFS	Low Carbon Fuel Standard
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MOVES	Motor Vehicle Emissions Simulator
NGV	Natural Gas Vehicles
NO_x	Nitrogen Oxides
OBBB	One Big Beautiful Bill Act of 2025
RFS	Renewable Fuel Standard
RIA	Regulatory Impact Analysis
RIN	Renewable Identification Number
RNG	Renewable Natural Gas
RVO	Renewable Volume Obligation

RVP	Reid Vapor Pressure
SBO	Soybean Oil
SKF	Sorghum Kernel Fiber
SRE	Small Refinery Exemption
STEO	Short-Term Energy Outlook
UCO	Used Cooking Oil
USDA	U.S. Department of Agriculture
UST	Underground Storage Tank
VOC	Volatile Organic Compound

List of Organizations Submitting Comments on the 2026–2027 RFS Set 2 Rule

Commenter or Organization Name	Docket Item Number
Abby Bouton	0669
Absolute Energy LLC	0650
Acelen Renewables	0590
ADM	0511, 0723
Advanced Biofuels Association (ABFA)	0588, 0691
Advanced Economic Solutions	0321
Aemetis, Inc.	0630, 0651
Ag Processing Inc (AGP)	0621, 0783
Agrilectric Power Partners	0357
Agwood Mill & Lumber	0523
Airlines for America (A4A)	0537
Alder Renewables	0478
Allotrope Cellulosic Development Company LLC (ACDC)	0405
Alternative Fuels & Chemicals Coalition (AFCC)	0629, 0663, 0780
Amanda Allen	0427
Ameresco Inc.	0383, 0539
America's Travel Centers and Truck Stops (NATSO), National Association of Convenience Stores (NACS), and SIGMA	0531
American Bakers Association (ABA)	0490
American Biogas Council (ABC)	0604, 0673, 0768
American Biomass Energy Association	0336
American Biomass Energy Association, American Loggers Council, California Biomass Energy Alliance & Michigan Biomass	0467
American Chamber of Commerce for Brazil (AMCHAM)	0489
American Coalition for Ethanol (ACE)	0462, 0712
American Farm Bureau Federation (AFBF)	0608, 0700
American Forest & Paper Association (AF&PA)	0547
American Forest Foundation (AFF)	0542
American Fuel & Petrochemical Manufacturers (AFPM)	0628, 0734
American Loggers Council (ALC)	0356, 0448
American Petroleum Institute (API)	0322, 0615, 0770, 0773, 0784
American Soybean Association (ASA)	0532, 0713
Amp Americas	0494, 0776
Anew Climate	0544, 0782
Angelo Sturino	0740, 0751
Anne Strang	0549
Anonymous	0320, 0432, 0495, 0556, 0601, 0678, 0747, 0748

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Anthony Stinton	0339
Arkema Inc.	0754
Assemblyman Christian Barranco, New Jersey Legislative District 25	0660
Associated Oregon Loggers, Inc. (AOL)	0482
Association of American Railroads (AAR)	0446
Atlantic Power and Utilities LLC et al.	0347
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Australian Renderers Association Inc. (ARA)	0580
Aztalan Bio LLC	0602, 0755
Baker Commodities Inc.	0524
Bayer Crop Science	0365
Beta Analytic	0515
Billie Lentz	0423
Biodiesel Coalition of Missouri (BCM)	0373, 0681
Bioenergy Association of California (BAC) et al.	0617
Bioenergy Development Group, LLC	0485
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Bob Poole	0345
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BrandSafway	0358, 0359
Braya Renewable Fuels	0475, 0706
Brenda Allen	0428
Brent Swart	0431
Brian Rumpf, 9th District, Assemblyman	0387
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Business Council for Sustainable Energy (BCSE)	0409
Butte County Fire Safe Council	0659
Caleb Ragland	0570
California Bioenergy LLC	0642
Canola Council of Canada (CCC) et al.	0454
Cargill, Inc.	0468, 0709
Castlerock Biofuels, LLC	0619, 0760
Cenovus U.S. Corporation	0460, 0731
Center for Biological Diversity	0553, 0620, 0622
Center for Climate and Energy Solutions (C2ES)	0592
CGB Enterprises, Inc.	0466
Chamber of Commerce of Southern New Jersey (CCSNJ)	0456
Chandra Blase	0568

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Charlene Koski et al.	0503
Chester County Chamber of Business and Industry	0342
Chevron U.S.A. Inc.	0498
Chief Ethanol Fuels	0396
China WTO/TBT National Notification & Enquiry Center	0589
CHS Inc.	0662
Clean Air Task Force (CATF)	0530
Clean Energy	0414
Clean Fuels Alliance America	0512, 0664, 0675
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Coalition of Small Refinery Owners	0636
Commonwealth Agri-Energy, LLC	0367
CommonWealth Resource Management Corporation	0319
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Consortium for Cultivating Human And Naturally reGenerative Enterprises (C-CHANGE), Grass2Gas	0406
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Dennis Fujan	0567
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Illinois Farm Bureau (IFB)	0392, 0715
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International Brotherhood of Electrical Workers (IBEW) Local Union 654	0341
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Iowa Biodiesel Board (IBB)	0625, 0695
Iowa Corn Growers Association (ICGA)	0762
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Iowa Renewable Fuels Association (IRFA)	0412, 0767
Iowa Soybean Association (ISA)	0641, 0761
Ironworkers Local Union 451	0507
J.J. White, Inc.	0350
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James Martin	0424
Jamie Beyer	0566
Jason Reichert	0560
Jeffrey Warmann	0561
Jim Parrish	0369

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Joe Benitez	0745
Joe Fortino	0557
John Young	0555
Jon Parker	0680
Jonathan Vitale	0343
Josh Williams, District 44, Ohio House of Representative	0366
Joshua Rahm	0563
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Kathryn Eastman	0744
Kelly Allen	0426
Kent Hoffman	0742
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Kyle Reedy	0688
Laborer's International Union of North America Local 413	0371
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Leif Burhans	0785
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Matthew Mills	0624
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McCrometer, Inc.	0483
Michael Lemon	0648

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Michael Ring	0743
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National Association of Convenience Stores (NACS) et al	0729
National Association of State Foresters (NASF)	0380
National Corn Growers Association (NCGA)	0496, 0774
National Energy & Fuels Institute (NEFI)	0323, 0618, 0719
National Farmers Union (NFU)	0325, 0516, 0752
National Oilseed Processors Association (NOPA)	0577, 0707
National Sorghum Producers (NSP)	0441
NE Renewable Power	0633
Nebraska Corn and Nebraska Corn Growers Association (NeCGA)	0404
Nebraska Ethanol Board (NEB)	0438
Nebraska Farm Bureau Federation (NEFB)	0721
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New Jersey Gasoline, C-Store, Automotive Association (NJGCA)	0402
New Jersey General Assembly	0397
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North Dakota Soybean Growers Association (NDSGA)	0533, 0701

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P. Remick	0670
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Professional Logging Contractors of the Northeast (PLC)	0450
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Randy Miller	0573
Randy Stewart	0750
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Renewable Biofuels LLC (RBF)	0526, 0697
Renewable Fuels Association (RFA)	0326, 0435, 0708
Renewable Fuels Nebraska	0461
Renewable Fuels Nebraska (RFN) and Nebraska Ethanol Board (NEB)	0775
Representative Elgin Rogers, Jr., Ohio House of Representatives, 42nd District	0518
Rincon Band of Luiseño Indians (Rincon Band)	0318
Rio Valley Biofuels	0331, 0543, 0781

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RPMG Inc.	0627
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Ryan Pederson	0666
Scott Gies	0444
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Senator Paula Hicks-Hudson, Ohio State Senator, 11th Senate District	0457
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Slippery Rock Borough, Butler County	0562
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Small Refineries of America (SRA)	0725
Society of American Foresters (SAF)	0519
South Carolina Forestry Commission (SCFC)	0374
South Dakota Soybean Association (SDSA)	0488, 0684
Southeastern Wood Producers Association, Inc.	0433
Southern Willamette Forest Collaborative (SWFC)	0595
State Senator Holly Schepisi	0395
Stephen Censky	0565
Stephen Lang	0738
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Sustainable Advanced Biofuel Refiners Coalition (SABR)	0327, 0647, 0726
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The Brazilian Sugarcane and Bioenergy Industry Association (UNICA)	0407
The Chamber of Commerce for Greater Philadelphia	0393
The Devonshire Group LLC	0623
The Partnership for Policy Integrity (PFPI) and the John Muir Project (JMP)	0541

Commenter or Organization Name	Docket Item Number
The Scoular Company	0690
The Sustainable Aviation Fuel (SAF) Coalition	0504
The Transport Project (TTP)	0486
Tree Energy Solutions (TES)	0458
Trenton Agri Products LLC (TAP)	0652
Twelve Benefit Corporation	0463
U.S. Canola Association (USCA)	0612, 0753
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Union of Concerned Scientists	0476
United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States & Canada	0401
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United Steelworkers (USW) Local 4-898	0355
University of Illinois at Chicago	0569
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Valero Renewable Fuels Company, LLC (VRF)	0370
Veriflux	0415
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Washington Department of Natural Resources (DNR)	0477
Washington State University (WSU) Pacific Northwest National Laboratory (PNNL) Bioproducts Institute (Bio-In)	0527
Waste Connections (WCN)	0534
Waste Management (WM)	0613, 0771
Weaver and Tidwell, L.L.P.	0616
Western Dubuque Biodiesel	0328
Western Plains Energy, LLC (WPE)	0376
Wisconsin Soybean Association (WSA)	0551, 0692
World Energy Net Zero Services, LLC	0502
Yosemite Clean Energy, LLC (YCE)	0554

Note: Individual comments from the public (and attachments submitted with comments) submitted to Docket No. EPAHQ-OAR-2024-0505 are assigned a unique 4-digit docket number that follows the base docket number (*i.e.*, XXXX, where “XXXX” represents the unique 4-digit document docket number). For example, Docket Item No. EPA-HQ-OAR-2024-0505-0500 is presented as 0500 in this table and within the text of this document.

1. Policy Objectives of the RFS Program

1.1 Broad Policy Issues Including Congressional Intent and Program Goals

Comment:

Several commenters expressed strong, general support for the proposed rule. Some commenters stated that they were pleased with EPA's efforts to ensure the RFS program supports rural America as Congress intended, while others stated that the proposed rule advanced food security through U.S. agriculture and strengthening supply chains domestically and globally.

Several other commenters described how the RFS program has benefited the country since its inception. Commenters noted that the RFS program had been instrumental in driving emissions reductions, enhancing American energy dominance, strengthening rural economies, and growing markets for American farmers. Commenters stated that the RFS program had added more than 20 billion gallons to the fuel supply annually, lowering consumer costs, creating rural jobs, and reducing carbon emissions by more than 1 billion metric tons.

Other commenters emphasized that the RFS program is essential to achieving American energy independence and dominance, meeting demands for transportation fuel, and growing the biofuel energy sector to benefit all Americans. The commenters noted that ensuring an abundant supply of liquid fuels from a diverse array of domestic sources is a policy well aligned with the Administration's shift away from electrification and focus on American energy dominance.

Response:

We appreciate the support for our proposed rule. In this final rule we are finalizing volume requirements that are slightly higher than those proposed for 2026 and 2027. We expect that these strong volume requirements will provide crucial support for domestic renewable fuel producers and parties that produce feedstocks used in the production of renewable fuels. As indicated by these commenters, we also project that the renewable fuel volumes we are finalizing in this rule will support job creation and rural economic development.

The RFS program has played a crucial role in supporting significant increases in the production and use of renewable fuels. Ensuring a growing supply of domestically produced renewable fuels, particularly those produced from domestic feedstocks, 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[1] and the energy dominance pillar of EPA's "Powering the Great American Comeback" initiative.[2] The requirements in this

[1] Executive Order 14154, "Unleashing American Energy," January 20, 2025 (90 FR 8353; January 29, 2025).
[2] 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.

final rule are responsive to input from key agricultural and energy stakeholders on ways to bolster the RFS program.

Comment:

A commenter urged EPA to swiftly implement the proposed RFS volumes, expressing trust that the volumes would not be undermined by small refinery exemptions (SREs) or subsequent changes to biomass-based diesel (BBD) volume objectives. The commenter expressed their continued support for innovation and the use of domestically produced, crop-based feedstocks to supplement the nation's fuel market.

Another commenter expressed the importance of RFS program communication and regulatory certainty, which they viewed as instrumental in helping companies forecast demand and pricing, while offering investors the confidence required to commit significant capital to new projects.

Response:

We recognize the importance of establishing timely RFS volume requirements for many stakeholders. We have worked to finalize this rule as expeditiously as possible in light of the many complex technical and policy issues involved in this rule.

Comment:

A commenter described the RFS program as flawed and that the end of the overoptimistic mandated volumes from Congress in 2022 should have been an opportunity to reassess the overall value and purpose of the RFS program. The commenter asserted that the proposed rule was a failure by EPA to recognize the market changes in U.S. oil supply and demand or the limitations to ethanol production and use that have been exposed in the 20 years since the original RFS program was created. The commenter further stated that the original national security justifications for the RFS program have been resolved through massively increased domestic production of oil, and that the program now exists to increase the use of biofuels and serve as a special interest subsidy.

Another commenter stated that the RFS program was intended to encourage innovation in renewable energy by incentivizing second-generation (cellulosic) biofuels, but that market has largely failed to materialize. Instead, the commenter argued, the market is oversaturated with first-generation biofuels (*e.g.*, corn ethanol), which provide fewer, and often negative, environmental benefits. The commenter concluded that there is no evidence that the proposal will encourage innovation in renewable energy.

One commenter noted that most of the original targets set by the RFS program for total renewable fuel and total advanced biofuel have not been achieved since 2013. The commenter called for revisions to the program, including better structure and more reasonable obligation targets.

Response:

We recognize that the original volume targets established by Congress for 2022 (36 billion gallons of renewable fuel) have not been met. However, we disagree with commenters' characterization of the RFS program as a failure, despite the fact that renewable fuel production and use have not met the very ambitious targets established by Congress. The volumes we are establishing for 2026 and 2027 represent the highest ever renewable fuel volumes established under the RFS program. These volumes reflect significant investments and development in domestic renewable fuel production, distribution, and use. In particular, the production capacity for renewable diesel (and advanced biofuel that generally qualifies as BBD) has increased dramatically in recent years. We recognize that there are currently limits to the volumes of renewable fuel that can be produced and used in 2026 and 2027. The volumes we are finalizing in this rule account for these limits, both to the production of renewable fuel (*e.g.*, limited production capacity of liquid cellulosic biofuels) and the consumption of renewable fuel in the transportation sector (for example, limits on the consumption of compressed natural gas (CNG), liquefied natural gas (LNG), and ethanol). Nevertheless, these limits are not static. We project that the strong volumes we are finalizing in this rule will promote further investment in the production and use of renewable fuels and that this investment will enable even greater use of these fuels in future years.

2. Legal Authorities

2.1 Legal Authorities in this Action

2.1.1 Set Statutory Language and Criteria

Comment:

A commenter urged EPA to expeditiously finalize the rule given the statutory deadlines for promulgating volumes. A commenter also suggested EPA afford obligated parties additional time for compliance when EPA is late in promulgating the standards. This commenter also suggested that adherence to the statutory deadlines is necessary to provide obligated parties certainty and notice.

Several commenters supported EPA's efforts to issue the standards by the statutory deadline for the 2027 standards. A commenter noted the importance of certainty to rural communities. A commenter also noted the importance of certainty in light of other uncertainties in the biofuels market this year.

Response:

EPA has worked to expeditiously finalize this rule. We recognize the importance of timely standards to provide certainty and notice to various stakeholders. As discussed in Preamble Section II.E, EPA has missed the statutory deadlines for determining the 2026 and 2027 volumes. EPA's regulations automatically extend the compliance deadline for the 2025 RFS requirements due to the delay in the 2026 standards.[3] This will provide stakeholders with additional time for compliance. As discussed in Preamble Section II.E, obligated parties will have at least one year to plan for compliance with the 2026 standards after the promulgation of this action.

Comment:

A commenter suggested that "existing compliance flexibilities … such as … carrying forward a deficit from one compliance year into the next" do not provide a mechanism for obligated parties to comply. The commenter suggested that carrying forward deficits does not mitigate the harm for obligated parties who choose to utilize the carry forward deficit provision for compliance with the 2025 or 2026 standards because compliance must be achieved the next year. The commenter stated that carry forward deficits "may lead to additional adverse economic consequences, accounting concerns, increased potential liabilities as RIN prices vary, and the obligated party's ability to access the credit markets." The commenter noted that diminished carryover RINs will allow fewer obligated parties the ability to carry over deficits and comply with the following year's obligations.

[3] 40 CFR 80.1451(f)(1).

Response:

The deficit carryforward flexibility is prescribed in the statute at Clean Air Act (CAA) section 211(o)(5)(D) and does require obligated parties to satisfy the deficit the following compliance year. However, we do not agree with the commenter that the statutory requirement to fulfill the deficit the following year eliminates its usefulness as a compliance flexibility. We expect obligated parties to weigh any benefits or disadvantages when choosing whether to carry forward a deficit. Nevertheless, given the additional time to acquire RINs provided by the deficit carryforward provision and in light of historical requests from stakeholders to provide additional time for compliance, we believe that the deficit carryforward provision is properly considered a compliance flexibility available to obligated parties. As noted in Preamble Section III.F, available carryover RINs have increased significantly since the Set 2 proposal. Therefore, we anticipate the deficit carryforward provision to continue to be a viable compliance flexibility for obligated parties.

Comment:

A commenter highlighted the importance of the statutory lead time to establish volumes in that context. The commenter also indicated that the late issuance of rules "increased the cost of RFS compliance." The commenter stated a desire to "preserve th[e] legal argument, knowing that the courts cannot forever ignore the plain statutory text," regarding the deadline for determining the applicable volumes under CAA section 211(o)(2)(B)(ii). The commenter suggested that the plain text of the statute prohibits increases in the volume requirements sooner than "14 months before the first year for which such applicable volume will apply."

Response:

The commenter did not provide any detail on how the late issuance of rules increases the cost of compliance, and thus EPA is unable to meaningfully respond to the comment. Nevertheless, we have not observed a link between the costs of compliance and the late issuance of volume standards.

We agree that missing the statutory deadline does not eliminate EPA's authority to establish the volume requirements. However, we disagree that EPA is unable to increase the volumes above the 2025 standards. Contrary to the commenter's suggestion, the statute does not speak to "increases" in the applicable volumes, and thus the plain language of the statute does not convey a prohibition on increases in the volume requirements if the statutory deadline is missed. The statute only provides a deadline for EPA but does not speak to what the impact of missing that deadline is. The D.C. Circuit has indicated that when EPA misses the very statutory deadline mentioned by the commenter, EPA is to "reasonably considers and mitigates any hardship caused to obligated parties by reason of the lateness."[4] The D.C. Circuit found EPA had adequately done

[4] *Ams. for Clean Energy v. EPA*, 864 F.3d 691, 718 (D.C. Cir. 2017) ("*ACE*") (challenge to EPA's authority to establish biomass-based diesel volumes requirements for the years 2014-2017).

so in the Set 1 Rule, which was based on similar considerations related to lateness EPA has considered in this rule.[5]

Comment:

A commenter suggested that the volumes are overly ambitious, citing the standard of review the D.C. Circuit utilized in *CBD*. The commenter stated that EPA's analysis of the statutory factors "Largely relies on unsupported assumptions to erroneously conclude that the … volumes… are feasible." The commenter also suggested EPA is limited to considering only the enumerated factors in CAA section 211(o)(2)(B)(ii) and that EPA improperly considered factors that Congress did not intend the agency to consider, such as trade implications. The commenter also suggested that the proposed volumes failed to consider whether the volumes are attainable.

Response:

We have considered the statutory factors enumerated at CAA section 211(o)(2)(B)(ii). As described in Preamble Section II, we are not limited to considering only the enumerated factors. However, we note the volume requirements we are finalizing in this rule only consider trade policies to the extent that policies enacted in other contexts (*e.g.*, OBBB) may have implications on biofuel and feedstock imports. We are not finalizing the proposed IRR provisions in this rule.

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[5] *Center for Biological Diversity v. EPA*, 141 F.4th 153, 183-4 (2025) ("*CBD*").

2.1.2 Other Statutory Authority

Comment:

A commenter noted the lack of explicit statutory authority to reopen a rule to increase the volumes of renewable fuel, in contrast to EPA's explicit waiver authorities which allow EPA to reduce the required volumes of renewable fuel. They suggested this "asymmetric authority" suggests EPA should be aggressive in setting future volumes and that such an approach would be consistent with Congressional intent to make the RFS "market-forcing."

Response:

We agree that the statute does not explicitly authorize EPA to increase volumes after they are established under CAA section 211(o)(2)(B)(ii). Nevertheless, EPA action to reduce volumes that are too high creates additional uncertainty in the market for both renewable fuel producers and obligated parties. EPA has, at times, reduced the volume requirements through its waiver authorities in CAA section 211(o)(7), and such actions required public notice and comment rulemakings to adjust the volumes. In the interim, EPA had to extend compliance deadlines for obligated parties to accommodate the changed obligations. Any action to adjust volumes after they are set is disruptive to the RFS program, and such actions should only occur if the statutory criteria in CAA section 211(o)(7) are met.

The volume requirements we are establishing for 2026 and 2027 in this action are based on our analysis of the statutory factors. They are not intended to be aspirational with the expectation that we will reduce the volumes if necessary. We continue to believe that it is preferable to establish volume requirements that can be achieved and are consistent with our evaluation of the statutory criteria.

Comment:

Some commenters stated that EPA's interpretation of the statute regarding the use of the cellulosic waiver authority and the set authority concurrently is wrong. They also suggested that EPA's interpretation undermines the incentives Congress created in establishing the RFS program. A commenter argued that the statutory factors should result in higher cellulosic biofuel standards than those proposed. Commenters suggested that, instead of setting cellulosic biofuel volumes as EPA proposed, EPA could instead use both the cellulosic waiver authority and the set authority to prospectively set the cellulosic volume for 2026. The commenter suggested that cellulosic waiver credits (CWCs) could be made available only at the end of the year to address any shortfalls. The commenter suggested making CWCs available is a better price stabilizing mechanism and contrasted that approach with the current application of the waiver authorities that allows obligated parties to wait until the end of the year to purchase RINs with the expectation that EPA will issue a waiver. Commenters suggested EPA could take the same approach for 2027, or assess the cellulosic market by November 30, 2026, and utilize the cellulosic waiver authority if justified at that time.

Some commenters argued that the cellulosic waiver authority can and should only be used prospectively, given the statutory language that it be used by November 30 of the preceding calendar year. Another comment suggested that the statute should be read such that EPA should set the cellulosic biofuel volumes at the maximum achievable, and assume no waiver will be trigged in the future. The commenter stated that this approach gives the industry a strong incentive to increase its cellulosic production capacity and mirrors the CAA's original structure of establishing aggressive cellulosic volume requirements far in advance while allowing the cellulosic waiver to serve as a last-minute safety valve.

A commenter highlighted the statutory deadlines and the interplay between them. The commenter noted that the cellulosic biofuel standard is to be set 14 months in advance of the compliance year, which has the potential to send a market signal and create long-term incentives. The commenter also noted that the cellulosic waiver authority, with its deadline immediately before the compliance year begins, is intended as a safety valve.

Response:

Consistent with EPA's interpretation of CAA section 211(o)(2)(B)(iv) in the Set 1 Rule,[6] and as described in Preamble Section II, EPA again reads this provision as prohibiting EPA from determining cellulosic biofuel standards for 2026 at the same time we issue a waiver under CAA section 211(o)(7)(D). Comments on the resulting volumes under the statutory factors are addressed in RTC Section 6.

Comments relating to the use of the cellulosic waiver authority are addressed in RTC Section 8.

[6] 88 FR 44468, 44479 (July 12, 2023).

2.2 Severability

Comment:

A commenter argued that the SRE reallocation volumes and the renewable fuel volumes are not severable. The commenter stated that SRE reallocation volumes are not part of the CAA or EPA's regulations and argued that the volumes are inextricably linked to the volumes in Set 2 proposal. The commenter suggested that the potential cost impacts of the SRE reallocation volumes has impacts on the entire RIN market. The commenter suggested that the SRE reallocation volumes and the Set 2 proposal have the same underlying assumptions and thus are economically and analytically inseparable.

Response:

While EPA appreciates that the SRE reallocation volumes impact the renewable fuel and RIN markets, we disagree that this impact does not allow the SRE reallocation volumes and the renewable fuel volumes to be severable. As described in Preamble Section IV, the SRE reallocation volumes are intended to require the retirement of carryover RINs associated with 2023–2025 SREs such that the renewable fuel volumes for 2026 and 2027 are realized in the market. Thus, the SRE reallocation volumes, given the influx of carryover RINs associated with 2023–2025 SREs, are not likely to have societal cost impacts because any cost impacts are a result of the production and use of renewable fuels.

We do acknowledge that the SRE reallocation volumes increase the percentage standards that apply to obligated parties. These higher percentage standards are projected to have an impact on the cost to consumers of transportation fuel, as discussed in RIA Chapter 10.5.4. These estimated fuel price impacts (0.5¢ per gallon in 2026 and 0.6¢ per gallon in 2027) are small relative to the overall estimated fuel price impacts of this final rule.

Comment:

A commenter suggested EPA implement a regulatory mechanism to increase the cellulosic biofuel volume requirement if the SRE reallocation volume provisions is invalidated, vacated, or otherwise removed as a result of judicial review or future agency action.

Response:

In this action we are not finalizing an SRE reallocation volume for cellulosic biofuel. Therefore, consideration of such a regulatory mechanism is beyond the scope of this action.

3. Cellulosic Biofuel

3.1 General Comments on Cellulosic Biofuels

Comment:

A couple of commenters stated that the final rule should align with Congressional intent to promote the growth of cellulosic biofuels or that increasing use of RNG promotes economic growth and energy independence. One commenter stated the current proposal would undermine existing investments. Relatedly, a commenter stated that their members have made business decisions and investments in reliance on the RFS volume requirements, including the 2025 cellulosic biofuel volume requirement.

Response:

The final volumes reflect our consideration of the statutory factors, and we expect them to continue encouraging investment in and development of cellulosic biofuels while complying with statutory requirements. As explained in Preamble Sections III and VI, we are setting the cellulosic biofuel volumes for 2026 and 2027 at the projected volume available. Our consideration of the projected volume available includes an assessment of the quantity of RNG used as transportation fuel, which is a statutory requirement for qualifying renewable fuel in the RFS program. Under CAA section 211(o)(7)(D)(i), this is the level to which EPA would reduce the cellulosic biofuel volume requirement if the Agency exercised the cellulosic waiver authority. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic biofuel volumes such that we do not anticipate needing to waive the volumes under CAA section 211(o)(7)(D). Comments related to the 2025 cellulosic biofuel volume requirement are responded to in RTC Section 6.

Comment:

A commenter asserted that policy shortcomings have resulted in the cellulosic biofuel program being a complete failure. The commenter stated that EPA has no choice but to continue to reduce cellulosic biofuel volume requirements.

Response:

While we acknowledge that current cellulosic biofuel volumes are lower than the levels[7] envisioned by congress in CAA, we do not agree that the program has been a failure. Cellulosic biofuel production has grown substantially in recent years, reaching record levels in 2025.[8] As discussed in Preamble Section III and RIA Chapter 7, we also are projecting robust cellulosic volumes for the years finalized in this rule.

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[7] CAA section 211(o)(2)(B)(III)

[8] 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.

Comment:

A commenter requested that EPA correct references in the DRIA to "renewable biogas" to RNG that is injected into the pipeline. The commenter noted that biogas is by definition renewable and clarified that it is the RNG that is interchangeable with fossil natural gas.

Response:

We thank the commenter for the input and have updated the RIA to clarify our terminology. Specifically, we reference biogas that is upgraded for injection into the commercial natural gas pipeline system and could be used to produce renewable fuel as renewable natural gas (RNG). Also, we use "renewable CNG/LNG" to refer to RNG when it is used as a transportation fuel in CNG/LNG vehicles, in contexts where such use is eligible for and results in RIN generation and separation under the RFS program.

Comment:

Commenters argue that EPA misread Congress's directive to consider infrastructure and costs when projecting cellulosic biofuel volumes and failed to show infrastructure limits that would justify lower obligations. They say EPA's station throughput analysis indicates earlier projected CNG/LNG use exceeds later proposals, so infrastructure is not the constraint, and retail volatility does not demonstrate one. They contend EPA improperly mixed fueling infrastructure capacity with the number of vehicles, and question how previously estimated capacity could become a substantial challenge for future volumes. They also assert that assessing existing fueling capacity is not required by statute, that EPA's estimates are overly conservative because they ignore excess capacity at stations, and that throughput is rising. In their view, infrastructure has not limited RNG growth, and dispensing capacity exceeds what EPA's cellulosic targets assume.

Response:

EPA is statutorily required to consider, inter alia, "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,"[9] in setting cellulosic volumes in years after 2022.

With this stated, we acknowledge that the method for analyzing fueling-station throughput may have underestimated actual throughput. Nonetheless, using our throughput methodology, we concluded that the capacity of the existing U.S. natural-gas vehicle fueling infrastructure would not constrain either the cellulosic volumes we proposed or the slightly higher volumes we are finalizing. The analysis, as described in the Set 2 DRIA Chapter 7.1.4.1, estimated fueling infrastructure capacity at 1,558 million RINs per year. Comparing this estimate with the finalized cellulosic volumes of 1,364 million RINs in 2026 and 1,424 million RINs in 2027 (see RIA Chapter 7), we determined that existing infrastructure would not be a constraint. We therefore agree with the commenter and do not anticipate that the capacity of existing U.S. fueling infrastructure to dispense natural gas for vehicles will be a constraint. We note that our cellulosic

[9] CAA section 211(o)(2)(B)(ii)(IV).

biofuel volumes would not be higher even with a higher estimate of CNG/LNG fueling capacity, as we project that the volume of qualifying RNG will be limited by the number of vehicles capable of using CNG/LNG as transportation fuel. Accordingly, this analysis was not used to develop either the proposed or the final cellulosic biofuel volumes. It was conducted only to provide EPA with additional insight into the CNG/LNG market. To clarify the extent to which this analysis was used when determining the final cellulosic volumes, we have removed it from the RIA.

Comment:

Multiple commenters urged EPA to adopt an automatic, transparent, and data-driven mechanism to raise the cellulosic biofuel volume requirement when cellulosic RIN generation exceeds the required volume, so that surplus RINs do not depress prices. They highlighted ongoing volatility in the D3 RIN market, with unpredictable and often low prices, and attributed this to a regulatory approach that only adjusts the cellulosic biofuel volume requirement downward to address scarcity. In their view, this approach fails the "neutral aim" standard established by the courts. The commenters further argued that not revising the cellulosic biofuel volume requirement upward to reflect market overperformance may conflict with the intent and text of the statute, because an oversupply of RINs without corresponding demand weakens the market signal.

Response:

We believe that the most effective and direct way to respond to the commenters' concerns is to establish cellulosic biofuel volume requirements that reflect the projected growth of the cellulosic biofuel industry based on available data, as we have done in this final rule. We do not agree that the text of the Energy Independence and Security Act of 2007 (EISA), the CAA, or our review of the statutory factors that form the basis of this final rule, compel us to adopt the automatic mechanisms requested by the commenters. The statute simply does not address, much less compel, any such automatic mechanism to retroactively adjust the volumes. The omission is especially notable as Congress did require EPA to make certain adjustments based on renewable fuel use in prior years. CAA section 211(o)(3)(C)(ii). The fact that Congress required the adjustment in CAA section 211(o)(3)(C)(ii) but not that preferred by commenters is strong evidence that the commenters' adjustment is not statutorily required.

We recognize the potential impacts of under-projecting the potential renewable fuel volumes, including the cellulosic biofuel volumes, when establishing the RFS volume requirements. The potential impacts of over- or under-projecting the potential supply of renewable fuel is one of the primary reasons we are establishing volumes for only two years in this action. Establishing volumes for relatively shorter time periods provides EPA with opportunities to consider additional data in establishing appropriate standards. We also note that the RFS program does contain provisions that function to mitigate negative price impacts for cellulosic biofuel and cellulosic RINs in the event that the production and use of these fuels exceeds the volume requirements. The RFS program allows obligated parties to carry forward unused RINs from one compliance year into the next, and to use these RINs from the previous compliance year to meet up to 20% of the current year's obligation. These carryforward provisions ensure that, within the 20% carryover limit, excess RINs generated in one year have value the following year.

Finally, we note that the D.C Circuit's direction to EPA to take "neutral aim at accuracy" is applicable when EPA is using our cellulosic waiver authority to reduce the required volume of cellulosic biofuel. While we have taken a similar conceptual approach in establishing the cellulosic biofuel volumes for 2026 and 2027 in this rule. We recognize there are differences between the statutory requirements for setting and waiving cellulosic volumes (and differences in the context between reducing the statutory volumes for one year and setting standards in the first instance for two years), and EPA is not resolving and need not resolve the question of whether we are statutorily bound to neutral aim at accuracy in establishing cellulosic biofuel volumes under the set authority.

Consistent with our approach in the Set 1 Rule, we believe that our methodology for projecting cellulosic biofuel production and use in this final rule are consistent with a "neutral aim at accuracy." The methodology we have used to project cellulosic biofuel production is not one "in which the risk of overestimation is set deliberately to outweigh the risk of underestimation."[10] Nor are the cellulosic biofuel volumes we are finalizing in this rule aspirational. Unlike the cellulosic biofuel volumes EPA established in 2013, which were based on production projections from potential cellulosic biofuel producers with no history of biofuel production,[11] there is now a commercial scale cellulosic biofuel industry and the cellulosic biofuel volumes we are establishing in this rule are primarily based on trends from historical data, recognizing limits on the ability of CNG/LNG being used as transportation fuel. The statutory set factors including, *inter alia*, "review of the implementation of the program" and "the expected annual rate of future commercial production of renewable fuels, including […] cellulosic biofuel" in our view allow us to consider "changes to the cellulosic biofuel market," which the D.C. Circuit has also condoned in the context of EPA's exercise of the cellulosic waiver authority in 2016.[12] CAA section 211(o)(2)(B)(ii).

The cellulosic biofuel volumes we are establishing in this final rule, as well as the underlying methodology, are consistent with our evaluation of the statutory factors under the Set authority in CAA section 211(o)(2)(B)(ii). They are achievable based on our projections of cellulosic biofuel production such that we do not anticipate that the Administrator will need to issue a waiver for these volumes.[13]

Comment:

A commenter stated that EPA has delayed approving RIN generation for renewable electricity for almost 15 years, which could quickly inject a substantial amount of D3 RINs into the market.

Response:

As discussed in Preamble Section VII and in RTC Section 10, in this final rule we are finalizing the removal of renewable electricity as a qualifying renewable fuel under the RFS program.

[10] *API v. EPA*, 706 F.3d 474, 479 (D.C. Cir. 2013) ("*API*").
[11] Id. at 428.
[12] *ACE*, 864 F.3d at 691, 724, 726-729.
[13] See CAA section 211(o)(2)(B)(iv).

Comment:

Commenters urged EPA to expand and account for biogas and RNG-based fuel pathways when setting cellulosic biofuel volume requirements. Several asked EPA to approve new biogas-derived pathways to avoid constraining a category with growth potential and to increase RIN supply, including approval of D3 RIN generation for renewable jet fuel using RNG and approval of a pending RNG-based renewable jet fuel pathway to generate D7 RINs. They also argued that the proposed cellulosic biofuel volume requirements do not reflect the potential use of RNG as a biointermediate and requested an approach to incorporate pathways likely to be approved soon. One commenter specifically recommended a mechanism to recognize the expected near-term contributions of nine pending biogas or RNG pathways and to allocate RINs to petitioning producers roughly equivalent to the number of RNG RINs retired on an MMBTU basis. Another commenter supported EPA's CNG vehicle growth modeling but cautioned against relying solely on the model to set future volumes, urging EPA to consider anticipated approvals of RNG pathways to decouple RNG demand projections from CNG growth.

Response:

EPA recognizes commenters' requests to expand and account for biogas- and RNG-based pathways when setting cellulosic biofuel volume requirements. However, for 2026 and 2027, our projections are based on the best available data at the time of our analysis. In our analysis we have only included currently approved RIN generating pathways, as the inclusion of RINs generated from pathways not yet approved to generate cellulosic biofuel RINs would be highly speculative. We will continue to evaluate and, as appropriate, approve biogas- and RNG-based pathways, assess the potential use of RNG as a biointermediate, and consider approaches that better reflect likely near-term approvals in future rulemakings, to the extent they are consistent with the statute. As pathways are approved and supply becomes demonstrable, we will incorporate these contributions in future rulemakings.

3.2 Methodology for Projecting Volumes

3.2.1 Methodology for Projecting Cellulosic Biogas Volumes

Comment:

Several commenters expressed concern that EPA projected cellulosic biofuel volumes based on consumption or demand rather than production. Many urged EPA to finalize the 2026 and 2027 cellulosic biofuel volumes to reflect RNG's production potential or growth rate, arguing this would incentivize RNG production, expand market participation, increase competition, and better reflect current technologies and regulatory realities. Some argued that a demand-based approach is inconsistent with the statute, noting that Congress designed the RFS program as a market-forcing policy and did not identify demand or consumption as factors for setting volumes. One commenter said the proposal does not align with Congressional growth targets for the cellulosic category, while another asked EPA to align the volumes with its statements in the proposed rule about RNG growth and Congressional intent. A few commenters cited *ACE* to argue that EPA may not rely on demand-side constraints.[14]

Response:

We recognize the continued growth in RNG production and have accounted for it in determining the final volumes, as discussed in RIA Chapter 7.1.4.2; however, as discussed in Preamble Section II, given the various statutory constraints and provisions, we are setting the cellulosic biofuel volume requirements for 2026 and 2027 at the "projected volume available."

These projections are our best estimate of achievable cellulosic biofuel growth for 2026 and 2027, accounting for statutory requirements. Historically, our projections focused on estimating future cellulosic biofuel production. In the Set 1 Rule, we set the 2023–2025 cellulosic biofuel volume requirements based on projected production and historical growth in cellulosic RIN generation, assuming production capacity, rather than end-use consumption, would be the primary constraint.[15]

For this rulemaking, however, we have refined our methodology to consider both production and consumption, as explained in Preamble Section III.A and RIA Chapter 7.1. Including this consideration is appropriate because cellulosic RINs for biogas-derived renewable fuel (*i.e.*, RNG RINs) are generated before the fuel is used for transportation. However, these RINs are not separated, and therefore not available for compliance, until the RNG RIN separator obtains documentation confirming that the volume of renewable CNG/LNG was used as transportation fuel. This change improves the accuracy of our projections and reduces the likelihood of retroactive waivers of RFS volume requirements. Such waivers reduce market certainty and undermine confidence in the volumes and standards we set, which can discourage investment in renewable fuel production.

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[14] *ACE*, 864 F.3d 691 (D.C. Cir. 2017).
[15] Set 1 RIA Chapter 6.1.3.

Regarding the commenters' suggestion that EPA is unable to consider demand-side constraints when determining volumes as based on legal precedent from *ACE*, we disagree. At issue in *ACE* was EPA's use of the general waiver authority under a finding of inadequate domestic supply. The D.C. Circuit held that the general waiver authority at CAA section 211(o)(7)(A) allows EPA to consider supply-side factors affecting the volume available to refiners, blenders, and importers, but does not permit EPA to consider the volume available to ultimate consumers or other demand-side constraints. In this final rule, EPA is not using the general waiver authority to reduce volumes. For 2025, EPA is implementing a partial waiver of the cellulosic biofuel requirement under the cellulosic waiver authority in CAA section 211(o)(7)(D). For the 2026 and 2027 volume requirements, EPA is setting volumes under the set authority.[16] Under the set authority, EPA is required to consider, among other factors, "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."[17]

Comment:

A commenter expressed support for EPA's determination that the market for biogas-derived CNG/LNG is limited by demand but stated that EPA must avoid using "aspirational methodology" to set a conservative cellulosic volume standard that does not exceed production. The commenter noted that if EPA misses low in setting standards, it allows for partial replenishment of the depleted carryover RIN bank, but if the Agency sets the standard too high, it must exercise its cellulosic waiver authority. The commenter argued that an excessively high mandate is arbitrary and capricious, leading to inflated RIN prices and increased market volatility. Relatedly, commenters raised concerns about uncertainties in projecting cellulosic biofuel volumes and urged EPA to set cellulosic volume requirements at realistic, achievable levels to avoid undesirable market impacts. At the same time, one commenter agreed with EPA that RNG production is not expected to be a limiting factor in determining volumes.

Response:

We thank the commenters for their support. However, as discussed further in Preamble Section II, given the various statutory constraints and provisions, we are setting the cellulosic biofuel volume requirements for 2026 and 2027 at the "projected volume available." Under CAA section 211(o)(7)(D)(i), this is the level to which EPA would reduce the cellulosic biofuel volume requirement if it exercised the cellulosic waiver authority. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic biofuel volumes at levels that are not expected to require later reduction through a waiver under CAA section 211(o)(7)(D). By establishing standards based on projected volumes available, we aim to provide regulatory certainty and stable price signals while preserving incentives for continued investment. We do not consider these volumes aspirational or conservative; they reflect a neutral assessment of current vehicle counts and historical growth in the CNG vehicle market using the best available data for this analysis.

[16] CAA section 211(o)(2)(B)(ii).
[17] CAA section 211(o)(2)(B)(ii)(IV).

Comment:

A couple of commenters objected to EPA's reliance on CAA section 211(o)(2)(B)(iv) to support its approach using demand to determine the cellulosic biofuel volume requirement. The commenters noted that EPA itself found that RNG production exceeds consumption, and that by using the definition of the "volume available" as the trigger for the cellulosic waiver, EPA did not apply a "neutral aim at accuracy" as required by *API*.[18]

Response:

We recognize the continued growth in RNG production and have accounted for it in determining the final volumes, as discussed in RIA Chapter 7.1.4.2. However, as described in Preamble Section II, we read CAA section 211(o)(2)(B)(iv) and CAA section 211(o)(7)(D) together to require EPA to set the 2026 and 2027 cellulosic biofuel requirements at no more than the "projected volume available." In making these projections, EPA appropriately considered the ability of vehicles to use RNG. Failing to account for vehicle use would result in a shortfall in RINs available for compliance in the stated years and would thus be in violation of CAA section 211(o)(2)(B)(iv). Contrary to the commenter's assertion, accounting for the vehicles that can use RNG, and thus can generate RINs is taking a "neutral aim at accuracy," because, as described above and in Preamble Section III, considering only the production of RNG would result in an over projection of cellulosic biofuel.[19]

Our interpretation of CAA section 211(o)(7)(D) is described further in Preamble Section VI and Section 8 of this document.

Comment:

A commenter stated that only changing the methodology to set volume obligations for one category of renewable fuel was arbitrary.

Response:

CAA section 211(o)(2)(B)(ii) establishes the process, criteria, and standards for setting the applicable annual renewable fuel volumes. It directs EPA, in coordination with USDA and DOE, to determine the applicable volumes for each renewable fuel category based on a review of the implementation of the program, an analysis of the statutory factors listed in section 211(o)(2)(B)(ii), and the additional criteria in CAA section 211(o)(2)(B)(iii)-(vi). Congress enumerated the factors EPA must consider but did not mandate any particular analytical methods or specify how EPA must weigh the various factors.

EPA has historically updated its methodology to assess cellulosic biofuel many times throughout the lifetime of the RFS program. This allows EPA to base each cellulosic biofuel volume requirement on the most up-to-date information available at the time of the rulemaking and provides a reasoned justification for EPA's volume projections. Maintaining an outdated

[18] *API v. EPA*, 706 F.3d 474 (D.C. Cir. 2013).
[19] See also *Growth Energy v. EPA*, 5 F.4th 1, 14-15 (D.C. Cir. 2021) ("*Growth Energy*").

methodology would be arbitrary. For cellulosic biofuel, EPA expects the market to be constrained mainly by consumption (see RIA Chapter 7.1.4.1 and Preamble Section III). Because no other renewable fuel can fulfill the cellulosic biofuel obligation, EPA's method for projecting and setting the cellulosic biofuel volume requirement is appropriately different from the methods used for the other renewable fuel categories.

EPA has also updated its analyses supporting the volume requirements for other renewable fuel categories, and thus the Agency is not only changing the methodology for one category of renewable fuel as the commenter suggests. For detailed discussions of the methodologies and analyses for the other renewable fuel categories, see RTC Sections 4 and 5.

Comment:

Several commenters stated that regulatory uncertainty under the RFS program and volatility in the RIN market pushed RNG producers to other markets in 2023, reducing D3 RIN generation and increasing sales to voluntary markets. They cite EPA's late finalization of 2023 volumes and added burdens from the Biogas Regulatory Reform (BRR) Rule, arguing that D3 shortfalls do not reflect CNG/LNG consumption limits. Related commenters warn that setting cellulosic volumes based on demand estimates without accounting for the BRR and Set 1 frameworks would harm the RNG industry. They contend EPA's conclusion on consumption constraints is arbitrary and overlooks factors affecting RIN generation from 2023 to 2025, including SRE handling, delays, and retroactive waivers, and say industry success depends on timely action, transparent volume-setting, and consistent enforcement.

Response:

Our partial waiver of the 2025 cellulosic biofuel volume requirement (described in Preamble Section VI and RTC Section 8) is based on the actual cellulosic RIN data available at the time of our analysis. Additionally, our final cellulosic volume requirements for 2026 and 2027 (see Preamble Section III and RIA Chapter 7.1) are based on our assessment of the CNG/LNG vehicle fleet. That assessment reflects the best data available at the time, and we do not believe it would be affected by these issues.

We also note that RNG producers shifting to other markets, together with the analysis described above, may indicate a consumption-limited market, which in turn can encourage producers to seek alternative outlets.

Comment:

A commenter expressed concern that the proposed cellulosic biofuel volume requirements for 2026 and 2027 rely almost exclusively on demand and ignores the continued growth rate of RNG production. The commenter urged EPA to reconsider the proposed volumes by analyzing recent RIN separation rates in 2025.

Response:

We recognize the continued growth in RNG production and have accounted for this growth in determining the final cellulosic biofuel volume requirements, as discussed in RIA Chapter 7.1.4.2. However, as explained in Preamble Sections III and VI, we are setting the cellulosic biofuel volume requirements at the projected volumes available. Under CAA section 211(o)(7)(D)(i), this is the level to which EPA would reduce the cellulosic requirement if it exercised the cellulosic waiver authority. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic volumes such that we do not anticipate needing to waive the volumes under CAA section 211(o)(7)(D). Accordingly, we do not adopt a production-only approach; we consider both production and consumption. As described in RIA Chapter 7 and Preamble Section III, demand-side factors play a critical role in projecting the number of cellulosic RINs that will be available.

Regarding the commenters' request to evaluate the proposed volumes using 2025 RIN separation rates, we have considered those rates. They were a major factor in our analysis of the 2025 waiver (see Preamble Section VI), which relied on the best available data at the time, including RIN separation rates.

3.2.1.1 Projected Production of Cellulosic Biogas

Comment:

A commenter expressed concern that that EPA's methodology for projecting cellulosic biofuel volume requirements relied heavily on historical data which fails to capture the full scope and pace of growth in the dairy RNG sector. Another commenter stated that industry data supports an anticipated growth in landfill RNG production of 37.5% between 2025 and 2026 and 18.2% between 2026 and 2027. The commenter urged EPA to update the RNG production and demand analyses to account for recent policy changes and the latest production trends.

Relatedly, several commentors argued that EPA should account for the growth rate of RNG production in setting the cellulosic biofuel volume requirements by applying the same methodology used for 2023–2025 with actual 2024 D3 RIN generation as the baseline. The commenter stated that this approach would establish significantly higher cellulosic biofuel volume requirements than those in the proposal.

Response:

We recognize continued growth in RNG production and based our projections on the most recent production data and historic growth rates, as described in RIA Chapter 7.1.4.2. While historic growth rates are not always predictive, we have used a growth rate methodology in prior years and found it to be a reliable indicator for this sector. Specifically, as discussed in RIA Chapter 7.1.1, EPA used historic growth rates 2020–2022 RFS Rule[20] and the Set 1 Rule.[21] Although this growth rate did not always accurately project cellulosic RIN availability[22] it was reasonably accurate in projecting cellulosic biofuel production.

Additionally, we recognize that our estimates for production may not capture all of the potential RNG production because they reflect only RNG production reported to EPA through EMTS; however, we do not expect RNG production to be the primary factor determining the number of cellulosic RINs available for compliance. As explained in RIA Chapter 7.1.4, demand-side constraints are the main limitation. Accordingly, even if projected cellulosic biofuel production were higher, it would not change our final volume requirements.

[20] 87 FR 39600 (July 1, 2022).
[21] 88 FR 44468 (July 12, 2023).
[22] See Preamble Section III.A.

3.2.1.2 Projected Use of Cellulosic Biogas as Transportation Fuel

Comment:

A commenter expressed general support for EPA's assessment of natural gas demand in the DRIA but suggested that some corrections may be necessary.

Response:

We appreciate the commenters' support. We have updated our calculations for the final rule to reflect the most current data available at the time of our analysis.

Comment:

A commenter stated that the approach used by EPA to estimate the maximum CNG/LNG demand is highly dependent on the trucking industry's adoption of the Cummins X15N engine and that EPA should use real-world market data before relying on sensitivity analysis to set volume standards.

Response:

We do not yet have sufficient evidence of a structural shift in trucking purchase behavior that would support a rapid increase in this engine's market share. Accordingly, we retained a neutral growth rate in this final rule based on historical registrations of CNG vehicles. Given the limited number of years covered by this final rule and the X15N's recent market entry in the U.S., we do not expect near-term adoption rates to materially affect the overall consumption of CNG/LNG such that it would impact our projected available volumes. We acknowledge that future growth in the consumption of CNG/LNG as transportation is largely dependent on adoption of the Cummins X15N engine, as shown in the sensitivity analysis we performed in the Set 2 proposal. We will continue to engage with stakeholders on this issue, as broader adoption of the X15N could substantially influence the cellulosic biofuel market and will be an important consideration in future rules.

Comment:

A commenter stated that EPA intentionally ignored market potential and underestimated CNG/LNG growth by declining to account for the potential adoption of the 15-liter Cummins X15N engine in its final consumption estimate despite stakeholder interest in this new engine. A few commenters discussed that multiple manufacturers make CNG/LNG engines that can substitute for traditional diesel engines in almost any application. Another commenter discussed that in a conservative growth scenario, if CNG engines reach 3% U.S. market share over the next few years, then demand would reach approximately 4.5 billion RINs.

Relatedly, a commenter stated that industry data and statements from Cummins' indicate that the Cummins X15N engine could reach 10% market penetration by 2030 and urged EPA to account for this in the final volume requirements.

Response:

Similarly to the previous response, we recognize the market potential of the Cummins X15N and have acknowledged it through the sensitivity analysis included in the Set 2 proposal (DRIA Chapter 7.1.4.1). However, we do not yet have sufficient evidence of a structural shift in trucking purchase behavior—such as sustained order volumes, production, and registrations—that would support incorporating rapid increase in the X15N's market share in our analysis. Given the limited years covered by this action (2026 and 2027) and the X15N's recent market entry in the U.S., we are retaining a growth rate based on historical CNG vehicle registrations and observed utilization, as described in RIA Chapter 7.1.4.1. Although current effects are limited, the X15N engine could have larger impacts on CNG fuel use in transportation in future years.

The commenter's scenario of CNG engines reaching 3% market share, implying roughly 4.5 billion RINs, exceeds what current data support and would risk over-estimating volumes such that EPA would be required to waive the volumes in a future action. We will continue to monitor orders and registrations, and we will revisit our consumption estimates in future rules if evidence shows sustained increases in adoption and market share.

Comment:

A commenter argued that EPA lacks statutory authority to use a "replacement efficiency" factor and that EPA improperly proposed to reduce volume requirements by applying a "saturation" rate. The commenter further asserted that using a "replacement efficiency" factor diminishes the program's effectiveness.

Response:

We are setting the cellulosic biofuel volume at the projected volume available. Under CAA section 211(o)(7)(D)(i), this is the level to which EPA would reduce the cellulosic requirement if it exercised the cellulosic waiver authority. This approach is consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic volumes at levels that are not expected to require later reduction through a waiver under CAA section 211(o)(7)(D).

Specifically, as described in RIA Chapter 7.1.4.1, if all fossil-based CNG/LNG were fully replaced by renewable CNG/LNG, total CNG/LNG demand would represent the maximum potential renewable CNG/LNG volume, with no further adjustment needed. In practice, facility-level constraints such as infrastructure limitations, costs, and other operational considerations make complete replacement unlikely, so some fossil-based CNG/LNG will remain in use. To better reflect realistic renewable CNG/LNG consumption in a saturated market, we calibrated our projections to observed market behavior, specifically drawing on experience in California, a state that provides stronger incentives for RNG than the rest of the U.S. Because these observations come from the most favorable U.S. market for RNG, we believe they represent an upper bound on feasible penetration; applying them nationally is therefore reasonable. This mechanism reflects our projection of how the market will respond, and while it does result in a reduction in the projection, that does not mean it is inherently impermissible. Failure to account for the “replacement efficiency” factor would result in volumes that are too high, and thus do not represent a “neutral aim at accuracy.”

Comment:

A commenter stated that EPA’s analysis of RNG demand inaccurately assumes the number of eligible transportation end users for RNG is finite and nearing saturation. The commenter discussed that economic factors not considered in the DRIA, including the 45Z credit and State clean fuel credits, will continue to drive CNG conversions. A couple of commenters discussed or provided data showing that the CNG or RNG may offer long-term savings in fuel and maintenance relative to diesel models, which they argued adds to the positive economics for adopting CNG engines.

Response:

We agree that CNG and RNG may offer long-term fuel and maintenance savings relative to diesel models. However, we disagree with the assertion that EPA’s demand analysis inaccurately assumes the number of eligible transportation end users for RNG is finite and nearing saturation. As described in RIA Chapter 7.1.4.1 and based on the best available data at the time of our review, the current CNG transportation fleet is already largely supplied by renewable CNG. As a result, further growth in RNG use within transportation must come from additions to the CNG/LNG vehicle population rather than from increased penetration within the existing fleet. In the near term, that growth is constrained by market realities: only a limited number of manufacturers currently offer CNG/LNG vehicles, production capacity and lead times are constrained, and model availability is concentrated in a few vocations. These factors, along with normal fleet replacement cycles and infrastructure considerations, mean that even with favorable economics, the CNG/RNG fleet cannot expand rapidly in the near term. Our projections incorporate these constraints while recognizing continued growth in several vehicle categories, including refuse haulers, single-unit trucks (excluding refuse haulers), and combination trucks. We will continue to monitor CNG conversions, OEM production capacity, and market adoption and will consider these trends in future rules.

Comment:

Many commenters cite an assessment by The Transport Project (TTP) of past and future transportation-sector natural gas demand. In that analysis, TTP says its market view largely aligns with EPA’s, but it identifies a few differences that materially affect cellulosic biofuel volumes and leads TTP to conclude that EPA underestimates demand.

Specifically, TTP started their analysis by reviewing EPA’s 2023 fuel-use findings and based on its survey-based analysis, estimates that total 2023 NGV consumption was about 10% higher than EPA’s estimate. TTP attributes most of this gap to EPA’s assumption about the average annual fuel use of straight trucks, which TTP argues is too low. TTP also contends that EPA’s straight-truck category misclassifies some vehicles. To address these issues and reflect higher natural-gas truck usage, TTP recommends increasing the fuel-use assumptions for straight trucks and combination trucks. According to TTP, this change would raise EPA's total and nearly close the gap with TTP's estimate.

For the years finalized under Set 2, TTP believes the main divergence between its forecast and EPA's comes from different market-penetration assumptions and higher average annual fuel use for trucks equipped with Cummins' X15N engine. Specifically, TTP states that high-use fleets adopting the X15N platform will consume about 50% more fuel than existing combination natural gas (NG) trucks. TTP also cites industry data and statements from Cummins indicating that the X15N could reach 10% market penetration by 2030, and urges EPA to reflect this in the final volume requirements. In its analysis, TTP holds mature markets (transit, refuse) roughly flat—so heavy-duty NG growth reflects new X15N deployments—while acknowledging that recent large transit-bus orders could alter transit assumptions. Finally, TTP expects recent regulatory changes—including the repeal of California regulatory authority and the voiding of EPA Phase 3 GHG rules—together with strong expected refuse orders, to expand traditional NG use. Accordingly, TTP estimates that EPA could raise proposed RNG volumes by 77.4 million ethanol-gallon equivalents (EGE) in 2025, 142.6 million EGE in 2026, and 338.4 million EGE in 2027.

Response:

We appreciate TTP's thorough assessment and have carefully reviewed their analysis of CNG usage. For the final rule, we have updated our analysis in RIA Chapter 7.1.4.1 using more recent data. Based on this update, we continue to believe our analysis provides the best available estimate of historical CNG fuel use in transportation. Specifically, by incorporating updated data, such as the updated 2023 vehicle counts and the estimated rates of fuel consumption and miles driven presented in RIA Chapter 7.1.4.1, our estimate of 2023 CNG fuel consumption has increased by approximately 5% over our estimate presented in our proposal. Though it remains below the commentators' estimated 2023 fuel consumption.

Regarding the commenters' analysis for 2026 and 2027, we acknowledge their statement that natural gas vehicles (NGVs), particularly straight trucks and combination trucks, may have higher usage than comparable diesel vehicles. We agree that the usage pattern assumption is a sensitive variable with a significant impact on the projected volumes in our analysis.[23] However, when this analysis was conducted, we could not identify robust, market-wide data on fleet usage patterns that would reasonably support adopting the more aggressive rates suggested by the commenter. We agree that some fleets likely operate their NGVs at higher utilization levels to maximize economics; however, given the available data, we feel that it is also possible that some fleets use their vehicles less than diesel-equivalent fleets, either because volatility in the natural gas and diesel price spread[24] can significantly affect payback periods[25] or because operators are more comfortable and familiar with diesel vehicles. In the absence of comprehensive, nationally

[23] For both 2026 and 2027, our analysis indicates that straight truck and combination truck categories account for approximately 37% of total estimated CNG consumption. See RIA Chapter 7.1.4.
[24] For a high-level comparison of CNG versus diesel fuel price comparisons, see DOE, "Alternative Fuel Price Report," October 2025, Figure 6.
https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_october_2025.pdf.
[25] See an example return on investment business case created by Hexagon Agility and available at: https://hexagonagility.com/make-the-switch/rng-for-heavy-duty-fleets-ebook.

representative data specific to natural gas vehicles we believe that taking a neutral approach, assuming NGV usage patterns are comparable to those of diesel vehicles, is the most appropriate and analytically defensible baseline for this final analysis.

Additionally, we recognize the market potential of the Cummins X15N and have acknowledged this potential through the sensitivity analysis included in the Set 2 proposal (DRIA Chapter 7.1.4.1). However, we do not yet have sufficient evidence of a structural shift in trucking purchase behavior—such as sustained order volumes, production, and registrations—that would support incorporating rapid increase in the X15N's market share in our analysis. Given the limited years covered by this action (2026 and 2027) and the X15N's recent market entry in the U.S.,[26] we are retaining a growth rate based on historical CNG vehicle registrations and observed utilization, as described in RIA Chapter 7.1.4.1. Although current effects are limited, the X15N engine could have larger impacts on CNG fuel use in transportation in future years.

Finally, we recognize that recent regulatory actions, including the June 2025 repeal of the Advanced Clean Trucks regulation and the August 2025 reconsideration of the Phase 3 regulation, could affect future CNG and LNG vehicle counts. However, we do not expect any resulting changes in fleet size to materially affect CNG and LNG transportation fuel consumption in 2026 or 2027, though we may see bigger impacts in future years.

Comment:

A commentor stated that EPA's reliance on its most recent Motor Vehicle Emissions Simulator (MOVES5) to linearly interpolate vehicle CNG/LNG counts using historical data was flawed because the model assumed implementation of these regulations for 2025–2030.

Response:

Regarding EPA's reliance on MOVES5, for single-unit trucks (excluding refuse haulers) and combination trucks, EPA used national CNG/LNG vehicle counts processed by the MOVES5 team for each calendar year, derived from vehicle registration data for 2014, 2020, and 2023. The MOVES5 team interpolated between those registration years to produce annual counts for the intervening years (2015–2019 and 2021–2022), and we relied on that fully interpolated time series in our analysis. Although MOVES5 includes forward-looking vehicle population trajectories that reflect anticipated market responses to the regulatory landscape at the time the model was developed, as discussed by the commenter, we did not use those future-year projections in our analysis for 2025–2030. Instead, our future-year counts are based on a neutral extrapolation of historical growth observed in the processed registration-based data.

Comment:

A commenter asserted that EPA should adjust estimates for expected use of RNG in CNG/LNG vehicles upward to reflect the Agency's intention to remove renewable electricity as a qualifying

[26] Cummins, "Cummins starts full production of X15N™, industry-first big bore natural gas engine, first on the Cummins HELM™ platform," September 12, 2024, https://www.cummins.com/en-na/news/releases/2024/09/12/cummins-starts-full-production-x15ntm-industry-first-big-bore-natural-gas.

renewable fuel under the RFS program. The commenter added that capital allocation is posed to move back to these vehicles and related infrastructure.

Response:

We recognize that the removal of renewable electricity as a qualifying renewable fuel under the RFS program could affect future CNG/LNG vehicle counts. To date, however, no parties have generated RINs for electricity under the RFS program, we therefore do not expect the removal of the eRIN pathway (discussed further in RTC Section 10) to materially affect renewable CNG/LNG use as transportation fuel in 2026 and 2027.

Comment:

One commenter argued that EPA underestimates the growth rate of school buses by using data from the COVID pandemic years that experienced higher drops in growth.

Response:

As discussed in Chapter 7.1.4.1, the school bus dataset used covers only March through November 2022 and does not capture trends over time. Given this limitation, EPA assumed zero growth, holding the number of CNG school buses constant throughout the analysis period. This decision reflects recent funding patterns that largely favor electric buses over CNG.[27] Because there was limited evidence at the time of this analysis to support future growth in the CNG school bus fleet, applying a growth rate could overstate CNG use in this sector. EPA therefore assumes no change in CNG school bus counts over time for this analysis.

We are aware of recent developments that may influence future CNG school bus adoption, including EPA's announcement to revamp the Clean School Bus Program.[28] EPA will continue to analyze this vehicle market in future rules. However, given the recent nature of these changes and the limited number of years that we are establishing volumes, we do not expect them to affect our current assumption of no growth or decline. Additionally, even if we applied a growth or decline factor, the impact on final volumes would be negligible. Under our analysis, school buses account for about 22 million RINs, which represents roughly 2% of the total cellulosic volumes of 1,364 million RINs in 2026 and 1,424 million RINs in 2027.

Comment:

Commenters stated that EPA's assessment of CNG/LNG demand is too limited because it overlooks transportation fuel markets that could grow with incentives for locomotives and domestic shipping, consistent with congressional intent. They argued that growth-oriented, market-forcing volumes are needed to sustain investment in using RNG in transportation and

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[27] EPA, "Clean School Bus Program Rebates." https://www.epa.gov/cleanschoolbus/clean-school-bus-program-rebates.

[28] EPA, "EPA Announces Path Forward to Revamp the Clean School Bus Program to Provide Safe, Affordable, Efficient Transportation for America's Youth." https://www.epa.gov/newsreleases/epa-announces-path-forward-revamp-clean-school-bus-program-provide-safe-affordable.

noted that EPA's projections exclude emerging transportation and shipping sectors. One commenter highlighted active investments in RNG for locomotives, including a dual diesel/RNG system expected to enter service in 2026 and RNG locomotives anticipated to begin production in 2028. Another commenter urged EPA to clarify and revise regulations related to "ocean-going vessels" and marine uses and questioned why marine uses of CNG/LNG were excluded from EPA's estimates.

Response:

We acknowledge the potential for locomotives and domestic marine markets to consume meaningful volumes of CNG, whether fossil based or renewable. However, at the time of our analysis we did not find evidence of material, ongoing use of CNG in these segments. Because data on consumption was limited, we did not include locomotive or domestic marine volumes in our near-term projections.

We recognize the desire for growth-oriented, market-forcing volumes to accelerate investment in RNG. However, we must establish cellulosic biofuel volumes consistent with statutory direction. Consequently, 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 EPA set the cellulosic fuel volume requirements such that we do not anticipate a need to further lower the requirement through a waiver under CAA section 211(o)(7)(D). Given the lack of demonstrated use in the locomotive and domestic marine segments, including substantial volumes from these markets at this time would increase the likelihood of having to reduce the applicable cellulosic biofuel volume requirement in the future.

With respect to marine uses, the CAA excludes fuel used in ocean-going vessels from the definition of transportation fuel under the RFS program.[29] EPA therefore did not count potential CNG/LNG use in ocean-going shipping. For domestic marine applications that are not ocean-going vessels, we did not have adequate data showing meaningful use during the period evaluated.

In sum, the final cellulosic volumes reflect the best available data, the statutory framework, and our intent to support continued growth in cellulosic biofuel volumes while setting volumes at achievable levels. We will consider new and available data on CNG/LNG use in locomotives and domestic marine applications in future rules.

[29] CAA section 211(o)(1)(L).

3.2.2 Methodology for Projecting Liquid Cellulosic Volumes

Comment:

Several commenters requested that EPA increase the cellulosic biofuel volume requirements, noting that 2025 production of corn kernel fiber (CKF) ethanol appears on track to exceed the Set 1 Rule estimates. Based on these trends, they argued that CKF volumes should be adjusted upward. One commenter specifically stated that 2025 production could reach up to 90 million RINs, exceeding EPA's projection of 77 million RINs.

Relatedly, commenters expressed mixed views on EPA's assumed 90% facility participation and 1% conversion efficiency for CKF ethanol. While some supported these assumptions, others recommended higher values.

Response:

Using the latest RIN generation data available at the time of the analysis, CKF ethanol generated 84 million RINs in 2025.[30] This outcome is generally consistent with our Set 1 projection of 77 million RINs, as both volumes are 80 million RINs when rounded to the nearest 10 million RINs. The Set 1 Rule analysis relied on a projection methodology that considered the size of ethanol facilities expected to register to produce cellulosic ethanol from CKF, the share of cellulosic versus starch ethanol expected at each facility, and the number of facilities anticipated to produce cellulosic ethanol each year. We then mapped an estimated production curve based on a ramp-up in capacity. Facilities that registered in 2023 were assumed to operate at 25% of potential capacity in 2023, those that registered in 2024 were assumed to operate at 50% of potential capacity in 2024, and by 2025 facilities registered to produce CKF were assumed to reach full capacity.[31] These assumptions supported the volumes established in the Set 1 Rule, and although the actual 84 million RINs is slightly higher than the projection, it remains in line with our assessment of 77 million RINs

As discussed in RIA Chapter 7.1.5, our assessment of CKF ethanol RIN generation for 2026 and 2027 assumes that 90% of all starch facilities will register to produce CKF ethanol. This effectively assumes that some ethanol producers may be unable or unwilling to perform the testing necessary to generate cellulosic RINs. Data submitted by renewable fuel producers generating cellulosic RINs for CKF ethanol indicates an industry-wide average conversion rate of about 1% among registered facilities; we therefore used a 1% conversion rate for this analysis. Some parties report achieving up to 1.5% using analytical methods consistent with EPA guidance, but we do not yet have sufficient data to support adopting that higher rate. Given these assumptions, the available data, and observed trends, we believe the CKF volumes projected in this rule are appropriate.

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[30] 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.
[31] See Set 1 Rule RIA Chapter 6.1.2.

Comment:

A commenter urged EPA to reevaluate D3 RIN accounting constraints that depress bioethanol exports and to adopt measurement methodologies that recognize D3 RINs for domestic cellulosic biofuel produced during co-processing even when the non-cellulosic co-product is exported. Specifically, a commentor argue that EPA's rules allow producers to flexibly assign D3 and D6 RINs across batches of co-processed cellulosic ethanol, as long as anti-hoarding provisions are met. However, they state that EPA blocks this flexibility when co-processed starch gallons are exported, a stance the commentor views as misguided and one that unnecessarily reduces the domestic supply of cellulosic fuel.

Relatedly, a commenter noted that RINs for CKF ethanol are generated at ethanol plants, so volumes for this pathway should be aligned with expected ethanol production rather than ethanol consumption. The commenter recommended that EPA review corn starch ethanol production capacity at facilities capable of producing ethanol from CKF and apply a 1% factor to total corn starch ethanol production to better reflect potential CKF output.

Response:

The RFS regulations provide the equations renewable fuel exporters must use to determine their exporter RVOs.[32] Under 40 CFR 80.1430(b)(1), the equation for determining the cellulosic biofuel exporter obligation uses the variable "VOL_k" for "a discrete volume of renewable fuel that the exporter knows or has reason to know is cellulosic biofuel that is exported in a single shipment." Therefore, under the circumstances presented by the commenter, the renewable fuel producer that proportionally generates D3 and D6 RINs on a co-processed batch and exports a portion of that batch must retire D3 RINs for the portion of the exported batch that the renewable fuel producer knows was cellulosic biofuel. Therefore, when estimating future CKF ethanol production, we consider only the corn starch ethanol consumption volumes described in RIA Chapter 7.6 and exclude volumes that are produced and exported.

Comment:

Several commenters asked EPA to revisit the 1% conversion efficiency, citing advanced fermentation technologies and testing methodologies to produce ethanol from hemicellulose in CKF and ongoing ASTM work on analytical methods to support additional sorghum kernel fiber (SKF) cellulosic ethanol. They noted that these developments will provide incremental increases in grain-fiber-based cellulosic ethanol and recommended incorporating these pathways into projections, even if they are not yet approved for RIN generation.

Response:

EPA appreciates the commenters' suggestions and acknowledges the technological and analytical advances they describe. As discussed in RIA Chapter 7.1.5, EPA continues to recognize the potential for grain fiber-based fuels, including ethanol produced from hemicellulose in CKF and SKF, to contribute to the cellulosic biofuel pool. Based on data submitted by producers

[32] 40 CFR 80.1430.

generating cellulosic RINs for CKF ethanol, the industry-wide average conversion rate among registered facilities is about 1%. We therefore use a 1% conversion rate in our analysis.

EPA is aware of ongoing ASTM efforts to develop and refine analytical methods for CKF and SKF, as well as advances in fermentation and testing intended to increase hemicellulose conversion. We will continue to engage with stakeholders and review data reported through the RFS program. As additional data becomes available and methods are finalized and shown to be practicable across facilities, we will consider how best to reflect them in future rules.

Because this action establishes volume requirements for 2026 and 2027, we do not expect these emerging methods and technologies to be adopted and scaled widely during those years in a way that would materially affect the finalized volume requirements. Therefore, our projections for 2026 and 2027 retain the 1% conversion assumption based on current data. If ASTM methods are finalized and adopted, and data reported to EPA show consistent, verifiable increases in conversion rates or expanded qualifying production, including production from SKF, we will evaluate those developments and their impacts on the cellulosic biofuel supply in future rules.

4. Biodiesel, Renewable Diesel, and Jet Fuel

4.1 Biodiesel, Renewable Diesel, and Jet Fuel Production Capacity

Comment:

Many commenters stated that production capacity is not a barrier to reaching and exceeding the 2 billion gallons of U.S. biodiesel production projected by EPA. Some commenters noted that EPA's DRIA indicated there is significant unused biodiesel production capacity in the U.S., allowing domestic biodiesel production to grow without requiring additional production capacity investments.

Some commenters provided detailed analyses of domestic BBD production capacity and proposed utilization rates of the BBD industry. A few commenters stated that recent analyses by EIA or commissioned studies found that feedstock supply was not a constraint to achieving EPA's proposed volumes.

One commenter stated that based on the most recent data from EIA, the U.S. ended May 2025 with domestic fuel production capacities of almost 2 billion gallons of biodiesel and 4.7 billion gallons of renewable diesel, indicating that domestic capacity for biodiesel and renewable diesel would not be a constraint to meeting proposed volume requirements.

Response:

EPA has updated its analysis in RIA Chapter 7.2 to reflect the current state of the BBD industry capacity. BBD production in 2024 and 2025 was far below the total available capacity per the U.S. Energy Information Administration (EIA). The 2026 and 2027 volumes we are finalizing in this action reflect an approximately 90% utilization rate of existing biodiesel and renewable diesel production capacity, in line with the utilization rates generally achieved by petroleum refineries and the historic highs achieved by BBD producers. These volumes, in combination with the recent changes to the 45Z credit, are expected to provide significantly greater support for domestic BBD producers, including biodiesel producers, and result in much higher utilization rates for the existing domestic production capacity.

Comment:

A commenter presented the findings of a commissioned market evaluation of 2026 and 2027 production capacity, indicating that the industry had demonstrated that it could operate at an 80% utilization rate and higher, relying on domestic production exclusively. Another commenter agreed that an 80% utilization rate was achievable, citing newer projections for renewable diesel, jet fuel, and naphtha production, but agreed with EPA's conclusions that domestic feedstock supplies alone would be insufficient to meet the proposed volumes, and that a combination of domestic and imported feedstocks would be needed to support at least an 80% utilization rate and generate the number of RINs required by obligated parties under the proposed rule.

Response:

BBD production capacity has increased since 2025 and the BBD industry, especially renewable diesel facilities, have demonstrated their capability to exceed 80% utilization, as discussed in RIA Chapter 7.2. EPA projects that the industry will exceed 80% capacity utilization during 2026 and 2027. EPA's assessment of available feedstocks is consistent with the commenter's conclusions that domestic feedstock supplies alone would be insufficient to meet the volumes in this final rule and that meeting these volumes will likely require the use of imported feedstocks (see RTC Section 4.2 for further discussion on our assessment of the available feedstocks).

4.2 Availability of Biodiesel, Renewable Diesel, and Jet Fuel Feedstocks

Comment:

A commenter stated that a combination of foreign and domestic feedstocks and fuels would be necessary to generate the number of RINs that obligated parties would need under the proposed rule to avoid harmful impacts to consumers and to support a strong fuel supply. The commenter provided a detailed table showing that total domestic feedstock availability without diverting feedstocks from other uses would likely be between 32.8 and 35.4 billion pounds in 2026 and 2027, respectively. These domestic feedstocks could produce 4.10 and 4.43 billion gallons of BBD, which the commenter noted aligns well with EPA's analysis of 4.319 and 4.619 billion gallons of BBD in 2026 and 2027, respectively.

Response:

EPA has updated its assessment of the feedstocks projected to be used to produce biodiesel and renewable diesel in 2026 and 2027 in this final rule. Our feedstock projections have been revised in light new data, including the changes to the 45Z credit and the observed impacts of those changes in 2025. Our feedstock projections also account for the fact that we are not finalizing the proposed import RIN reduction provisions in this action.

We acknowledge that meeting the renewable fuel volume requirements we are finalizing in this rule will likely require the use of imported feedstocks. Our projection of the production of BBD from domestic feedstocks in this final rule (4.5 billion gallons in 2026 and 4.7 billion gallons in 2027) are similar to, but slightly higher than, those suggested by the commenter. These projections include a small amount of diversion of domestic feedstocks from existing uses to biofuel production. Much of the imported feedstocks we are projecting in 2026 and 2027 is expected to come from Canada and Mexico, as imported feedstocks from these countries can be used to produce biofuels eligible for the 45Z credit. We do project the continued of imported feedstocks from other countries, particularly the use of feedstocks that qualify for greater credits values under California's LCFS program.

Finally, we note that there is significant uncertainty in our projections of the feedstocks that will be used to produce BBD in 2026 and 2027, as this feedstock mix can and will be a function of a wide range of economic and policy factors. Nevertheless, given the large global supply of BBD feedstocks that could be available, we believe that our overall assessment of the quantity of qualifying BBD that could be supplied to the U.S. in 2026 and 2027 is robust.

Comment:

A commenter commissioned an updated analysis of feedstock availability from S&P that included the new tariffs on imported biofuel feedstocks, Canada's low carbon fuel program, the expiration of the blender's tax credit (BTC), and its replacement with the less valuable 45Z credit and stated that domestic feedstocks alone would be inadequate to meet the proposed BBD volumes and imported feedstocks would need to increase. The commenter further argued that based on the findings of this updated analysis, EPA's proposed BBD volumes would be arbitrary.

Response:

EPA acknowledges that domestic feedstocks alone will likely be inadequate to meet the volumes set in 2026 and 2027. In this final rule we have updated our feedstock projections. We project that approximately 70–75% of the feedstocks used to produce BBD in 2026 and 2027 will be produced from domestic feedstocks, while the remaining 25–30% will be produced from imported feedstocks (See RIA Chapter 7.2 for further discussion of feedstock growth projections and the effects of the 45Z credit and other incentives). Aggressive crush capacity expansion for canola and soybeans as well as diversion from non-biofuel uses could increase the domestic feedstock availability in future years. As mentioned by the commenter, S&P Global projects annual increases of 250 million gallons of new soybean oil crush available to BBD producers through 2027. This, while higher than EPA's more conservative estimate of 140 million gallons per year through 2027, is possible given increasing announcements of new soybean crush capacity as of the time of writing.

We project that all the BBD needed to meet the volume requirements we are finalizing in this rule could be produced from existing BBD production capacity. Domestic BBD production, even in cases where imported feedstocks are used, provides multiple benefits including benefits to energy security and rural economic development. See Preamble Section III for further discussion of our justification of the volumes in this final rule.

Comment:

A commenter stated that EPA's assertion that the supply-demand curve will stabilize based on increased soy and canola crush capacity is incorrect, further describing how recent policy changes will impact such projections and that there was an overestimation in domestic feedstock availability. The commenter provided statistics from a recent USDA forecast for the July 2025 World Agricultural Supply and Demand Estimates (WASDE) report to support their claims.

Response:

EPA believes domestic virgin oilseed crush capacity will continue to grow. Our projections of the increase in the soybean and canola crushing capacity in the U.S. and Canada are based on facilities that have already begun construction. We expect that the strong incentives for increased biofuel production provided by this final rule will result in high capacity utilization from both new and existing oilseed crushing facilities. The latest WASDE projections agree. As discussed in greater detail in RIA Chapter 7.2, USDA projects 4 billion gallons of soybean oil crush alone in 2026/2027 and projects an annual increase of 50 million gallons of soybean oil supply available to domestic producers. Other estimates are more optimistic, with the American Soybean Association projecting 350-million-gallon annual increases (though predicted from 2023-2025) and S&P Global predicting 250-million-gallon annual increases through 2027.

Comment:

A commenter stated that the proposed volumes of BBD will drive significant demand for domestically grown feedstocks and with an improvement to crop yields, projected growth in U.S.

soybean and corn production is adequate to meet the proposed volumes. Another commenter stated that the proposed BBD volumes would only incentivize the use of less than 65% of available capacity for production, while an average U.S. BBD producer requires 85% utilization to remain viable and that domestic production is more than adequate to meet proposed volumes.

Response:

The final BBD volume requirements are likely to drive demand for biofuels feedstocks. However, due to constraints in domestic oilseed crushing capacity, we do not project that domestic feedstocks alone will be sufficient to produce the BBD volumes we project will be needed to meet the volumes in this final rule. Without significant diversion of seed oils from food markets, we project that some level of imported feedstocks will be required to meet the volumes.

We recognize the benefits of high utilization rates of existing production capacity for domestic BBD producers. The final volumes reflect approximately 90% capacity utilization of available domestic BBD production capacity. We project that, even though we are not finalizing the IRR provisions in this final rule, domestically produced BBD will have a strong advantage over imported BBD due to the changes to the 45Z credit. We have already seen the impact of these changes in 2025, with imports of BBD falling by approximately 80% relative to import levels in 2024. While there may be some cases where imported BBD continues to be economically competitive in 2026 and 2027, we project that the vast majority of the supply of BBD used in these years will be sourced from domestic BBD producers.

4.2.1 Availability of Domestic Feedstocks

Comment:

Some commenters described detailed information on growth trends, technology advancements, and updated feedstock availability for soybean oil (SBO), canola oil, distillers corn oil (DCO), animal fats, used cooking oil (UCO), and intermediate oilseeds to support their claims that production capacity is poised to grow.

Response:

We have revised our projections of available BBD feedstocks in 2026 and 2027 based in part on our consideration of the information submitted by these commenters. Based on our review of the available data, we have concluded that while domestic feedstocks availability is expected to continue to grow through 2027 domestic feedstocks alone are not sufficient to meet the volume requirements we are finalizing in this rule without the significant diversion of feedstocks from non-biofuel markets. However, we also project that significant quantities of qualifying feedstocks may be available from other countries, and we expect that BBD producers will continue to use imported feedstocks when these feedstocks are economically competitive. Given the large quantity of potentially available feedstocks from other countries, we have concluded that feedstocks are not a constraint to achieving the analyzed volumes of this rule. As discussed in RIA Chapter Section III, EPA has set volumes for BBD based on consideration the implementation of the RFS program to date and our analysis of the statutory factors (presented in the RIA for this rule).

Comment:

Some commenters expressed concern regarding EPA's assessment of U.S. production capacity and stated that there were inadequate domestic feedstocks to meet the proposed volumes. A commenter stated that the fewest number of gallons required to meet the proposed rule volumes using only domestic feedstocks and production capacity is approximately 5.6 billion and 5.9 billion gallons in 2026 and 2027, respectively. Another commenter provided their own detailed analysis of BBD feedstock supply and consumption indicating that overall consumption outpaced the rate of domestic production. The commenter further discussed how the feedstocks EPA assumes will be available to meet proposed volumes are actually being diverted away from other existing uses, leading to adverse outcomes.

Response:

EPA projects that some of the required volume of BBD in this rule (approximately 25–30%) will be met with biodiesel and renewable diesel made from foreign feedstocks. EPA also projects that up to 20% of soybean oil currently used for non-biofuel uses may be used for biofuel in 2026 and 2027. Feedstock markets are uncertain, and individual procurement decision-making often relies on prices at time of trade, geographic constraints, and unique logistical challenges that lead to different choices of input feedstocks. As a result, while some feedstock sourcing is very likely (*e.g.*, domestic fats, oils, and greases and domestic soybean oil beyond what is currently used in other markets), the remaining supply is uncertain and could come from a variety of different sources, including imports or diverted virgin seed oils from non-biofuel markets. Nevertheless, given the large global supply of BBD feedstocks that could be available we believe that our overall assessment of the quantity of qualifying BBD that could be supplied to the U.S. in 2026 and 2027 is robust.

We also recognize that increasing BBD production by diverting feedstocks from existing uses can have adverse outcomes, particularly if the market has insufficient time to prepare for these market changes. In this final rule, we are not finalizing the proposed import RIN reduction provisions. Our decision to not finalize these provisions in this rule is in part due to concerns about the potential short-term disruptive impacts these provisions could have if markets are not given adequate notice and opportunities to adjust their sourcing and supply plans. We also expect that increasing demand for biofuel feedstocks such as vegetable oils will incentivize increased investment in the production of these feedstocks and that over time the combination of increased domestic production and use of available substitutes will provide sufficient quantities of feedstocks for both the biofuel and non-biofuel markets.

Comment:

A commenter expressed concerns about EPA's assumptions regarding SBO processing, stating that EPA incorrectly assumed all domestic renewable diesel capacity could economically process SBO as many planned crushing plants would not be online until 2026 at the earliest. They also argued that SBO for use in food and export markets would need to decline as subsidized biofuel use increased, leading to inflationary impacts on commodity and food prices and requiring substitution to less economic feedstocks, some of which would be imported. A few commenters cited recent USDA projections of domestic feedstock availability, including SBO, which determined that U.S. soybean availability was 3.05 billion pounds short of what EPA is projecting would be needed.

Response:

Contrary to the commenter's claims, EPA did not assume that all renewable diesel producers could or would process soybean oil in 2026 and 2027 in our proposed rule. Instead, we projected that a wide range of feedstocks (including imported feedstocks) would continue to be used in these years. In this final rule we have updated our projections of available feedstocks in 2026 and 2027 (see RIA Chapter 7 for more detail). As in the proposed rule, we continue to project that a wide range of feedstocks, both domestic (soybean oil, FOG, and corn oil) and imported (FOG and canola oil) will be used to produce biodiesel and renewable diesel. This alleviates any potential pressures to divert soybean oil from other markets, and better matches production to available feedstock supply of domestic feedstocks with some uses of imported feedstocks when economical.

Soybean oil is a viable feedstock for many renewable diesel facilities, although logistics do present some challenges for those facilities not located near soybean crush plants or along a transportation network with sufficient capacity to accept large soybean oil shipments. Current crush capacity and the geographic proximity of crush facilities to biodiesel and renewable diesel facilities, especially midcontinent, will allow U.S. producers to maximize the use of soybean oil in domestic BBD production. As the commenter states, further crush capacity will also come online in 2026, further bolstering the use of domestic soybean oil in domestic BBD production. Our analysis of available feedstocks includes a consideration of the timeline for new oilseed crushing facilities and capacity expansion at existing crushing facilities to begin production. We have updated our assessment of expected oilseed crushing capacity in the U.S. and Canada in 2026 and 2027 in this final rule using the most recent data available.

While increased biofuel volumes do have some impact on commodity prices and food prices, EPA projects no more than 20% diversion of soybean oil from non-biofuel uses. Much of the increased production of renewable fuels expected will come from other sources, including imported feedstocks. These price impacts send a signal to the oilseed market to continue to invest in oilseed crushing capacity to be able to meet the demand for vegetable oil in both the biofuel and non-biofuel markets.

Comment:

A commenter stated that estimates of BBD produced from canola are underestimated, and that no growth is projected in domestic canola production despite recent investments in processing facilities for canola. The commenter suggests that canola can be included as a double-crop with soybeans. The commenter also states that the extension and modification of the 45Z credit provides incentives and policy stability for expanded canola production.

Response:

EPA acknowledges a robust North American canola market. Crush capacity has grown, inclusive of swing plants and dedicated canola plants, and is projected to continue to grow. See RIA Chapter 7.2 for a further discussion of canola oil crush and growth rates. In this final rule, we have updated our projections of the feedstocks likely to be used to produce BBD supplied to the U.S. in 2026 and 2027. These updated projections include significantly higher volumes of BBD produced from canola oil. We recognize the potential for increased production of canola oil in the U.S.; however, we currently project that the increase in the use of canola oil for BBD production will largely come from greater quantities of imported Canadian canola oil. The 45Z credit is indeed a strong driver for greater canola oil production and use in the biofuel market and will continue to do through 2029.

4.2.2 Availability of Imported Feedstocks

Comment:

A commenter stated that feedstock supply is not a constraint in achieving higher BBD volumes, citing an analysis that took a tiered approach to assess available global supplies and uses by other countries and markets, and inelastic demands on existing feedstocks. The study projected that RFS-approved feedstocks would increase by 25 million metric tons to 177 million metric tons by 2027, equivalent to 50 billion gallons of renewable diesel. Based on their analysis, the commenter stated that feedstock supplies available for use in the U.S. through 2030 are more than enough to meet their forecast demand, after accounting for food.

Response:

EPA's analysis of available feedstocks is generally consistent with this commenter's conclusions. Given the large supply of potential BBD feedstocks in both the U.S. and other countries we do not expect that feedstock availability will limit the supply of BBD to the U.S. in 2026 and 2027. We note, however, that BBD produced from different feedstocks is expected to have different impacts on some of the statutory factors. BBD produced in the U.S. from domestic feedstocks is expected to provide greater rural economic growth benefits. BBD produced from feedstocks diverted from other markets may result in higher prices for these feedstocks. The volumes we are finalizing in this rule reflect EPA's efforts to holistically balance the statutory factors. See Preamble Section III for more information on EPA's balancing of the statutory factors to determine the final volumes for 2026 and 2027.

Comment:

Commenters stressed that the proposed BBD volumes would require a continued reliance on foreign feedstocks. One commenter stated that production of BBD relied heavily on imported feedstocks and fuel from 2022–2024 and that EPA's proposal exceeded domestic feedstock availability by 3 billion gallons, based on different growth rates of SBO presented by the DRIA and American Soybean Association. Another commenter described the canola trade between the U.S. and Canada, stating that Canada is planning investments and growth of 35% in canola oil output from 2024 levels, which would provide ample feedstock to support the increased volume.

Response:

EPA's analysis also suggests that some of the BBD supplied to meet the volumes in this final rule (approximately 25 – 30%) will be produced from imported feedstocks due to limitations on the supply of domestic feedstocks. The use of imported feedstocks will largely be driven by the lower cost of UCO compared to virgin seed oils and state clean fuels programs, such as California's LCFS and similar programs in Oregon, Washington, and New Mexico that provide greater credits for biofuels produced from these feedstocks. At the Federal level, the 45Z credit has advantaged domestic feedstocks and feedstocks from Mexico and Canada. While global feedstock availability continues to grow and be available to U.S. BBD producers, domestic feedstocks are projected to make up the bulk of the feedstocks used to produce domestic BBD.

Comment:

One commenter expressed concern that EPA's reliance on 2024 data to estimate proposed volumes for 2026 was inappropriate, arguing that assuming the 2024 volumes would be available again in 2026 was arbitrary because of the impacts of the 45Z credit and renewable fuel policies. The commenter noted that imports of renewable fuels have fallen from 2024 to 2025 as a result of the 45Z credit and global policy shifts and EPA cannot assume that the imported feedstocks would return to the market.

Response:

EPA has update our analyses and projections of available feedstocks in this final rule using the best, latest data available. Where possible, EPA has updated analyses to use data from 2025 or early 2026. 2025 saw significant decreases in the supply of imported BBD and BBD produced from imported feedstocks, likely due to the changes to the 45Z credit. In our updated BBD supply projections in this final rule we have projected no imported BBD in 2026 and 2027 and a lower supply of BBD produced from imported feedstocks that we observed in 2024 and 2025. While we recognize there is significant uncertainty in the types of feedstocks that will be used to produced BBD supplied to the U.S. in 2026 and 2027 we believe our projections are reasonable based on the data available at the time the analyses for this final rule were completed.

Comment:

One commenter raised concerns about logistical barriers to EPA's proposed BBD volumes based on the assumption that most U.S. renewable diesel plants will be able to access larger volumes of SBO from domestic and foreign sources to comply. The commenter provided examples of land use conflicts and terminal capacity issues on the west coast, Midwest rail line delivery schedules, and Jones Act vessel issues in the Mississippi River to illustrate that larger volumes of SBO from global supply chains may not be economically or logistically feasible. The commenter urged EPA to carefully consider whether there is sufficient infrastructure to deliver the feedstocks that would be required by the proposal.

Response:

EPA concurs that there are significant logistical barriers to domestic BBD producers, particularly on the West Coast, procuring sufficient volumes of domestic soybean oil. EPA is not finalizing the import RIN reduction provisions in this rule, easing the need for maximal procurement of domestic feedstocks. We expect that some domestic BBD producers, particularly those designed to receive waterborne shipments of imported feedstocks, will continue to use these feedstocks to some degree in 2026 and 2027. However, over time, incentives put in place by the 45Z credit and trade dynamics will shift logistics networks towards providing more capacity for more competitive domestic feedstocks.

4.3 Imports and Exports of Biodiesel, Renewable Diesel, and Jet Fuel

Comment:

Several commenters expressed concern about EPA's assumptions that there will not be significant changes to net BBD imports through 2030, stating that in 2025, D4 foreign/import RIN generation was down 85% compared to the previous year, whereas export RINs were only down 11%. The commenters further noted that this discrepancy means that the U.S. would become a net importer of RINs, not a net exporter, and thus the DRIA should incorporate this change in net trade to avoid a lack of feedstock supply. Another commenter discussed specific import statistics presented in the DRIA, stating that several assumptions were not accurate.

Response:

EPA has updated its use of publicly available import statistics where possible, drawing on a variety of sources such as UN Comtrade, USDA, and industry data. 2025 saw approximately 80% fewer imports of BBD compared to previous years, and the dynamics that caused that (*e.g.*, 45Z credit, uncertain international trade relationships) remain. In this final rule we have projected no net imports of BBD in 2026 and 2027, though we continue to project that some BBD producers will continue to use imported feedstocks (see RTC 4.2). More detail on our updated analysis can be found in RIA Chapter 7.2.

4.4 Projected Rate of Production and Use of Biodiesel, Renewable Diesel, and Jet Fuel

Comment:

A commenter noted that currently, renewable diesel and biodiesel consumption significantly exceeded renewable jet fuel consumption. As renewable jet fuel would likely be produced from the same feedstocks used to produce biodiesel and renewable diesel, the commenter stated that renewable jet fuel must be considered in setting volume projections.

Response:

Renewable diesel and jet fuel are often co-located production facilities, as further discussed in RIA Chapter 7.2. Because nearly all renewable jet fuel is currently produced at the same facilities as renewable diesel using the same feedstocks we have not attempted to separately project renewable jet fuel production. Instead, our projections of renewable diesel supplied in 2026 and 2027 are inclusive of both renewable diesel and fuel sold as renewable jet fuel. However, EPA is aware of growing renewable jet fuel production, and any potential decoupling of renewable jet fuel and renewable diesel production in the future will be assessed in consideration of future volume-setting rules.

Comment:

A commenter argued that recent policy changes (*e.g.*, 45Z credit) would limit any growth in the renewable jet fuel production in the U.S.

Response:

Renewable jet fuel continues to grow according to the latest EIA information. The impact of the changing incentives to the 45Z credit on renewable jet fuel production in 2026 and 2027 are uncertain, although the incentives for its production have diminished compared to 2024. We expect that any decrease in renewable jet production in 2026 and 2027 would likely result in an increase in renewable diesel production in these years as these fuels are generally produced at the same facilities from the same feedstocks.

Comment:

Other commenters provided a different view, stating that additional facilities are expected to come online in future years, adding production capacity that could provide for an increased RVO. Some explained that an alcohol-to-jet (ATJ) fuel process requires different feedstocks than renewable jet fuel, and additional facilities are expected to come online to supply ATJ fuel, and investments in these projects and the ATJ industry would suffer without stronger volume requirements.

Response:

This is correct—renewable jet capacity continues to grow according to latest EIA data. The final volume requirements in this rule are well above those in the Set 1 Rule, providing strong incentives for all biofuels, including renewable jet fuel produced from hydrotreating renewable lipids and ATJ. The renewable fuel volumes we project will be supplied to meet the volume requirements in this final rule include significantly higher volumes of renewable diesel than previous years. As discussed in previous responses, the projected volume of renewable diesel includes renewable jet fuel. While we may see some limited production of ATJ through 2027, we note that there is currently not a general pathway for ATJ and that only one facility has received a facility-specific pathway for this fuel. We therefore do not project appreciable volumes of ATJ will be produced in 2026 and 2027. EPA acknowledges the rapidly changing renewable jet fuel industry and will continue to monitor its growth, using all available latest data to evaluate it.

4.5 Other Comments on Biodiesel, Renewable Diesel, and Jet Fuel

Comment:

Commenters provided feedback regarding renewable jet fuel, requesting that EPA continue to support via policy signals, a strong renewable jet fuel and ATJ market as it aligns with the President's goals for energy independence, lessens greenhouse gas (GHG) emissions, and maintains demand for American feedstocks.

Another commenter noted that the heating oil market could accommodate additional concentrations of biofuels into the market supply and that a strong volume requirement could provide the market signal needed to invest in biofuel integration.

Response:

The RFS program contains volume requirements for four broad categories of renewable fuel: cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel. The RFS program is therefore not well positioned to provide support for specific types of renewable fuel. The volume requirements for 2026 and 2027 in this rule represent a strong mandate based on maximizing domestic production capacity for all renewable fuels, including renewable jet fuel (inclusive of ATJ and heating oil.

Comment:

A commenter stated that EPA's analysis relied on limited data and significant assumptions, leading to arbitrary proposed volume requirements. The commenter requested that EPA revise the DRIA and conduct additional analysis to assuage concerns regarding feedstock availability, supply shortages, and impacts to transportation costs.

Response:

EPA relies on all publicly available data in order to quantify the biofuels industry and project appropriate volumes. We have reviewed all comments submitted on the Set 2 proposal and have updated our analyses for this final rule after considering input from stakeholders and additional information not available at the time of the final rule. In the analysis for this final rule, we have relaxed some of the simplifying assumptions we made in analyzing the potential impacts of the proposed rule. Specifically, we no longer assume that imports of BBD and feedstocks used to produce BBD continue at the historically high levels observed in 2024 through 2027. In another change from the proposed rule, our analysis now considers the possibility that BBD producers will divert domestic feedstocks from other markets for biofuel production. EPA strives to continuously improve its analyses where possible and welcomes further specific feedback on how its analyses can be improved.

Comment:

A commenter provided detailed discussion of the history of the RFS program regarding biodiesel, including describing the legislative history, EPA's implementing regulations, and domestic and foreign production. The commenter discussed that Congress has sought specifically to promote biodiesel under the RFS program, including when it expanded the RFS program to include a specific category for BBD. The commenter went on to provide detailed comments encouraging EPA to create specific volume requirements for biodiesel, which the commenter stated would support existing investments. Among other comments and rationale, the commenter disagreed with previous statements made by EPA indicating that the statute suggests that qualifying biofuels should compete with each other within each standard, reasoning that Congress sought to increase production of biofuels indicating that it believed the volumes should be additive to compete with petroleum, not with each other. Furthermore, the commenter said that, even if Congress had sought to have biofuels compete with each other within the relevant categories, the commenter believes that co-processed renewable diesel and jet fuel should compete with renewable diesel and jet fuel, since neither meets the definition of BBD in the statute and biodiesel does not participate in the jet fuel market.

The commenter provided a specific recommendation for a biodiesel-specific volume requirement (whether solely through the BBD volume category or through a subcategory) of 2 billion gallons. The commenter described how this proposal could benefit the program, including greater diversification and innovation, reduced prices at the pump, and greater RIN liquidity through additional RIN generators.

The commenter went on to argue that the proposed specific volume requirement for biodiesel is consistent with EPA's statutory authority under the "set" provision, and EPA could "simply amend" 40 CFR 80.1427 to add a provision that requires the minimum BBD volume to be met by D4 RINs with fuel code of 20. The commenter noted that although EPA has previously argued against a biodiesel-specific requirement based on its claim that the definition of BBD is not limited to the specific product "biodiesel," even if this were true, the BBD definition would merely define the outside scope of the fuels that could qualify to meet the BBD program, not those fuels that must be used to meet the BBD volume requirement.

A commenter similarly recommended that EPA revise the definition of "renewable diesel" such that renewable diesel that meets ASTM D975 is not a "diesel fuel substitute." The commenter further argued that EPA should "correct" the pathways for renewable diesel and jet fuel in Table 1 to 40 CFR 80.1426.

Response:

EPA has addressed similar comments in previous actions. The changes to the RFS program requested by the commenter contradict the plain language of EISA. This act defined the term "biomass-based diesel" to mean "renewable fuel that is biodiesel as defined in section 13220(f) of this title, and that has lifecycle greenhouse gas emissions… that are at least 50 percent less than the baseline lifecycle greenhouse gas emissions" and is not co-processed with petroleum.[33]

[33] CAA section 211(o)(1)(D).

Section 13220(f) defines biodiesel as "a diesel fuel substitute produced from nonpetroleum renewable resources that meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 7545 of this title."[34] Both biodiesel and renewable diesel are diesel fuel substitutes that meet the registration requirements for fuels and fuel additives under this section, and thus both fuels meet the definition of BBD in EISA, assuming the lifecycle GHG reduction requirements are met and these fuels are not co-processed with petroleum feedstocks. The approach to implementing the RFS program suggested by the commenter, wherein EPA would acknowledge that non-biodiesel fuels such as renewable diesel meet the statutory definition of BBD but are not eligible to satisfy an obligated party's BBD obligation, would be inconsistent with the plain language of EISA.

Further, we consider the changes requested by the commenter to be beyond the scope of the proposed rule. We acknowledge that we have a statutory obligation to review the implementation of the program to date, however this obligation does not enable EPA to adopt significant programmatic changes in a final rule without giving adequate notice and the opportunity for public comment. Neither, as suggested by the commenter, does the fact that the commenter raised similar issues in a previous rule and during the public hearing for this rule address our requirements to provide notice and opportunity for public comment.

[34] 40 U.S.C. § 13220(f)(1).

5. Ethanol

5.1 E10 Blendwall and Total Gasoline Demand

Comment:

A commenter discussed that the Alternative Transportation case in EIA's Annual Energy Outlook 2025 (AEO2025) forecasts growth in total ethanol consumption from 2026 to 2027, predominantly due to increases in the ethanol blend rate rather than expansion in gasoline usage. The commenter stated that the forecasted concentrations of 10.56% and 10.63% in 2026 and 2027, respectively, are close to EPA's projected rates of 10.54% and 10.58%. The commenter stated that the projected ethanol blend rates are justified given ongoing expansion in the use of E15 and sales of E85.

Response:

EPA has updated its projection of total ethanol consumption and ethanol concentration in the gasoline pool using the best data available. EPA agrees that increases in ethanol consumption are associated with increased ethanol blend rates. Ethanol consumption has always been heavily dependent on gasoline consumption, as blending up to E10 was the only infusion of ethanol into the transportation fuel market for many years. E85 was once a contributor to this market for a brief period but decreased until the recent increase in California. Consumption of ethanol in E15 has seen a steady increase over the years; however, total ethanol consumption is still largely a function of gasoline consumption given the limited number of retail stations offering higher-level ethanol blends and the limited sales of these fuels. See RIA Chapter 7.5 for more detail on our update projections of ethanol consumption in 2026 and 2027.

Comment:

A commenter expressed concern that in formulating AEO2025, EIA appropriately relied on laws and regulations in effect during late 2024 but that incentives have been substantially reduced with the recent enactment of the One Big Beautiful Bill Act of 2025 (OBBB). The commenter stated that this reduction in incentives is expected to result in slower electric vehicle adoption and, consequently, higher motor gasoline demand than forecasted. The commenter noted that while this impact will likely be small in 2026, it will increase gradually over the coming years and will result in an underestimation of future ethanol demand.

Response:

EPA projects future ethanol consumption mostly based on trend data from retail station counts and nationwide sales or station throughput. EPA also tracks other factors that influence ethanol consumption, such as historically with the Biofuels Infrastructure Partnership (BIP) and Higher Blends Infrastructure Incentive Program (HBIIP), as well as currently with the 45Z credit. Although slower electric vehicle adoption rates are possible, we are unable to estimate the impact of these changes in 2026 and 2027. The ethanol projections in this final rule use the best available data at the time of our analysis. In the long run, we recognize that changes in projections of electric vehicle sales can impact projections of gasoline consumption, but we do not expect that any reductions in electric vehicle sales resulting from the changes in OBBB will significantly impact gasoline consumption in 2026 and 2027. As OBBB was only recently implemented and the effects of such legislation may take years to be seen, it is more likely that the full effects of this bill will not be seen until after 2026 and 2027.

5.2 Projected Volumes of Higher-Level Ethanol Blends

Comment:

A commenter discussed EPA's analysis of infrastructure limitations in projecting volumes of higher-level ethanol blends. The commenter noted that in the ten years since the Stillwater Associates' 2015 study referenced by EPA, there was no longer an incremental cost for installing E15-certified above-ground equipment when replacing older components and the amount of E15-incompatible above-ground retail equipment still in retail service is quickly diminishing. However, the commenter discussed that E15-certified underground storage tanks (USTs) come at a cost premium reflecting the need for different materials of construction, additional costs for certification and EPA-documentation, and reduced scale economies compared to non-E15 certified tanks. The commenter stated that retailers installing new USTs need to weigh the additional procurement cost against the perceived likelihood of switching a tank to E15 service and the cost of an early replacement, which could impact industry adoption of E15.

A commenter discussed that Minnesota currently offers E15 at 520 retail locations for an average discount of $0.17 per gallon as compared to E10. The commenter expressed support for E15 becoming the new normal fuel in the State.

Response:

EPA agrees that it may be possible for some retail outlets to offer E15 without the need to replace above-ground equipment (*i.e.*, gasoline pumps); however, HBIIP data shows that retail outlets usually replace or add both dispensers and underground storage tanks to enable dispensing/selling E15. The commenter is correct that the installation of a new E15-certified UST is a large cost with the potential for incidental costs to be incurred during the installation. More information on this topic can be found in RIA Chapter 10. While the availability of E15 is increasing in some states, we project that a relatively small percentage of the total retail fuel stations will offer E15 through 2027 based on observed trends in the number of stations offering E15 (see RIA Chapter 7.5 for more details on our E15 projections).

Comment:

A commenter stated that EPA's assessment of potential E15 and E85 volumes fails to account for factors that would affect D6 RIN values, including the import RIN reductions, the 45Z credit resulting from the enactment of OBBB, and increases in U.S. tariffs. The commenter recommended that EPA consider the consequent effect of these factors on E15 and E85 volumes in the final rule.

Response:

EPA discusses the factors the Agency considers when evaluating and projecting ethanol volumes, which include incentives and market trends, in a previous response. Furthermore, we note that, consistent with the commenter's request, we have taken the factors identified by the commenter into account in developing the ethanol projections in this final rule. This includes the impact of the 45Z credit and our decision not to finalize the proposed import RIN reduction provisions. We recognize that increased incentives for ethanol, whether through higher D6 RIN prices or changes to the 45Z credit, could enable greater discounts for higher-level ethanol blends such as E15 and E85. At this time, we do not have sufficient data to project the impacts changes to these incentives may have on the pricing or sales volumes of these fuels. We note, however, that the historical data EPA used to project average sales volumes of E15 and E85 covers years when RIN prices were relatively high and relatively low. Average sales of E15 and E85 do not appear to be correlated with RIN prices.

Comment:

A commenter discussed several factors that supported increased projections of E15 and E85 in future years, including: several State markets now allow year-round sales of E15, California is setting records for E85 use, EPA's emergency waivers kept E15 use available during summer 2025, some Midwest States can now offer E15 year-round, and blending economics for ethanol remain positive.

Response:

Information on EPA's methodology for projecting E15 volumes can be found in RIA Chapter 7.5. EPA has considered the factors identified by the commenter, including California's potential adoption of E15, but the impacts of that change may take several years to seen in the data.

EPA also recognizes that sales of E85 are and have been significantly higher in California that have been observed in other states. To better reflect these high sales volumes, we are separately projecting E85 consumption in California and the rest of the U.S.

We are also aware that stakeholders are pursuing multiple approaches to allowing E15 to be sold with the same volatility as E10 during the summer months. EPA's projections of E15 consumption are based on historical data. In every year since 2019, E15 has been able to be sold nationwide with the same volatility as E10 during the summer months. Our projections for 2026 and 2027 therefore implicitly assume that this will continue to be the case in 2026 and 2027, or that in the alternative, the lack of the volatility waiver for E15 during the summer months will not negatively impact the overall sales volumes of this fuel. Finally, we note that our projections of E15 sales have a very small impact on our overall estimates of ethanol consumption in 2026 and 2027. For example, in 2026 we project that approximately 1 billion gallons of E15 will be sold. If we had projected twice this volume of E15 sales in 2026 (2 billion gallons), it would only increase our projections of total ethanol consumption by about 50 million gallons, assuming the additional billion gallons of E15 would otherwise have been sold as E10.

Comment:

A commenter projected that a growing number of fueling stations will offer E15 as stations invest in equipment upgrades.

Response:

In this final rule we have updated our projections of the number of stations offering E15 in 2026 and 2027. We currently project that the number of stations offering E15 will increase by approximately 400 stations per year through 2027. See RIA Chapter 7.5 for more information on these projections.

Commenters representing retail stations indicated that, while it may be the case that much of the existing tankage at retail is compatible with E15, tank compatibility with E15 is not the same as the entire underground storage systems being compatible with E15 or with those systems being approved for E15 use. Parties storing ethanol in underground storage systems in concentrations greater than 10% are required to demonstrate compatibility of their entire underground storage systems with the fuel, through either a certification or listing of underground storage system equipment or components by a nationally recognized, independent testing laboratory for use with the fuel, written approval by the equipment or component manufacturer, or some other method that is determined by the agency to be no less protective of human health and the environment.[35] These requirements are designed to protect against equipment failure that could lead to leaks and to satisfy insurance requirements. The use of any equipment to offer E15 that has not been demonstrated to satisfy these certification requirements, even if that equipment might technically be compatible with E15, would pose potential liability for the retailer. In sum, even if a retailer's installed tanks are technically compatible with E15, the ability of that retailer to sell E15 may be significantly limited by the incompatibility of other components in the underground storage system and by an inability to demonstrate such compatibility. Upgrading retail infrastructure to allow a retail station to sell E15 is not a simple matter. We further discuss infrastructure constraints on E15 use in RIA Chapter 7.5.

Comment:

A commenter stated that EPA does not consider mid-level ethanol blends (*e.g.*, E20–E50) in its analysis of ethanol consumption, even though these fuels can be used in flex-fuel vehicles and are offered at 1,844 U.S. fueling stations.

Response:

There is no data on the consumption of mid-level ethanol blends other than E15 and E85 for the nation as a whole. Minnesota collects data on sales of all blends of gasoline as part of its tax collection, and mid-level ethanol blends accounted for only 1% of all E15–E85 blends.[36] Insofar as this data is representative of the nation as a whole, not explicitly accounting for sales of E20–E50 in the projection of total ethanol consumption for 2026 and 2027 does not have a meaningful impact on the results.

[35] See 40 CFR 280.32. This rulemaking does not reopen these regulations.
[36] "2024 Minnesota E85 + Mid-Blends Station Report," available in the docket for this action.

5.3 Projected Rate of Production and Use of Domestic Ethanol

Comment:

A commenter expressed concern that EPA's projections of ethanol consumption fall below recent actual observed levels or the volumes likely to be achieved through 2027. The commenter discussed that actual U.S. ethanol consumption reached 14.26 billion gallons in 2024 and 2025 year-to-date U.S. ethanol consumption was 3% higher than the same period in 2024, which suggests that total domestic ethanol consumption could surpass 14.6 billion gallons throughout 2025. The commenter highlighted that EPA's projections estimated conventional ethanol consumption to be only 13.78 billion gallons in 2026 and 13.66 billion gallons in 2027.

Another commenter expressed support for EPA's intended use of the latest EIA forecasts of gasoline and ethanol consumption in the final rule. The commenter recommended that EPA use forecasts from the Alternative Transportation case in AEO2025, which forecasts total ethanol consumption to be 14.20 billion gallons in 2025, 14.49 billion gallons in 2026, and 14.53 billion gallons in 2027 due to increases in the blend rate.

Response:

As described in RIA Chapter 7.5, EPA has revised its projection of total ethanol consumption in 2026 and 2027 to approximately 14.4 billion gallons in each year, which is in line with the estimate provided by the commenter. This revised projection is largely based on updated available data since the Set 2 proposal, most notably the change from AEO2023 to AEO2025. AEO2025 contained a significantly larger projection of gasoline consumption in 2026 and 2027 compared to AEO2023, which resulted in larger volumes of ethanol consumption in this final rule compared to the Set 2 proposal. We have also updated our projections of the consumption of higher-level ethanol blends such as E15 and E85 for this final rule (see RIA Chapter 7.5 and RTC Section 4.2).

Comment:

A commenter argued that EPA's projections of ethanol use in 2026 and 2027 are too low because EPA's method effectively assumes that the RFS program does not exist and disregards the likely effects of the import RIN reduction proposal and the 45Z credit.

Response:

As described in previous responses, EPA revised its projection of ethanol consumption in this final rule using updated data, including AEO2025. EPA also takes into account incentives that may affect ethanol consumption, including the 45Z credit. However, EPA is not finalizing the proposed import RIN reduction provisions in this final rule, and thus the ethanol projections do not account for this change to the RFS program.

Any increased incentives for ethanol consumption, whether the result of changes to the 45Z credit or higher RIN prices in the RFS program, are only likely to impact the sales of higher-level ethanol blends, as we project that nearly all gasoline sold in 2026 and 2027 will contain at least 10% ethanol with or without the RFS program. While these incentives may have some impact on the sales of higher-level ethanol blends, the sales of these fuels are largely limited by infrastructure constraints and the relatively small number of retail stations offering these fuels. Over time, we project that higher incentives will likely incentivize a larger number of stations to sell higher-level ethanol blends. Our projection of total ethanol consumption in 2026 and 2027 includes projections of increasing sales of E15 and E85 that generally are not projected to occur but for the RFS program.

Comment:

A commenter noted that given the limited market penetration of E15 and E85 due to regulatory barriers, typically 1–2 billion gallons of BBD is used to comply with the D6 RVO, creating an economic linkage between D6 and D4/D5 RINs. The commenter argued that the impact of the approximately $0.90 per RIN upward movement in the D4/D5 RIN price will enable bioethanol to price out biodiesel from the implied D6 RVO and potentially increase volumes by about 1 billion gallons relative to 2023 levels. The commenter also stated that analysis suggests there is up to about 4 billion gallons ethanol of current surplus E85 and E15 retail infrastructure that would be sufficient to handle an additional 1 billion gallons of potential U.S. ethanol demand compared to EPA's assumptions.

The commenter also argued that EPA understates achievable ethanol usage by at least about 1 billion gallons in 2026 and 2027 and that the market could produce, deliver, and consume at least about 3 billion gallons of ethanol per year above EPA's projections. The commenter analyzed five potential constraints: the statutorily required ratio between the advanced and total renewable-fuel standards, production capacity, feedstock, distribution capacity, and consumption capacity.

For feedstock, the commenter assumed that the total acreage devoted to corn would equal the corn acreage in 2007 and concluded that the available feedstock could support 16.69 billion gallons of corn ethanol in 2026 and 17.46 billion gallons of corn ethanol in 2027. For distribution capacity, the commenter assumed the current number of E15 and E85 stations remains constant and typical total fuel throughput rates per station, resulting in incremental ethanol consumption (above displaced E10) of 4.17 billion gallons in 2026 and 4.36 billion gallons in 2027. The commenter accepted EPA's estimates of production capacity and Stillwater Associates' conclusion of vehicle consumption capacity, but stated EPA's suppression of the statutory ratio has no practical effect for 2026 or 2027.

A commenter discussed EPA's estimates and Stillwater Associates' analysis of E15 and E85 infrastructure capacity, which the commenter estimated corresponds to projected E15 sites operating at 12% of capacity in 2026 and 13% in 2027, non-California E85 sites operating at 5% of capacity in 2026 and 2027, and California E85 sites operating at 34% of capacity in 2026 and 35% of capacity in 2027. The commenter estimated the capacity to deliver E15 and E85 disregarding the potential for additional station conversion in response to RFS-driven incentives. For 2026, the commenter calculated a national capacity of 7.5 billion gallons per year for E15 and 5.7 billion gallons per year for E85, with incremental ethanol over displaced E10 of 0.39

billion gallons per year and 3.78 billion gallons per year, respectively. For 2027, the commenter calculated a national capacity of 8.6 billion gallons per year for E15 and 5.9 billion gallons per year for E85, with incremental ethanol over displaced E10 of 0.44 billion gallons per year and 3.92 billion gallons per year, respectively. The commenter concluded that there is a large excess in station capacity to deliver E15 and E85 to the public compared to EPA's projected E15 and E85 volumes in 2026 and 2027, suggesting a zero cost in the near future for E15 or E85 infrastructure to meet greater demand for ethanol, including for vehicle usage, than EPA's analysis recognizes.

However, the commenter noted that their analysis did not consider U.S. exports of fuel grade ethanol. The commenter discussed that the U.S. ethanol industry surpassed Brazil as the world's largest ethanol exporter over the past decade and presented EIA data reporting U.S. fuel-grade ethanol exports, which increased from 398 million gallons in 2010 to 1,924 million gallons in 2024. The commenter stated that the linkage between production and exports suggests that U.S. ethanol producers will increase operating rates above domestic demand only when that incremental production is profitable.

Response:

These comments address many potential constraints to the production and consumption of ethanol considered by EPA in our analyses for this final rule. In projecting the volume of ethanol that could be used as transportation fuel in the U.S. in 2026 and 2027, EPA considered the domestic production capacity for ethanol (including available supply of feedstocks such as corn to ethanol producers). We determined that the domestic production capacity for ethanol was highly unlikely to limit the use of ethanol as transportation fuel in 2026 and 2027, even after accounting for the strong export markets for ethanol.

We also recognize that, if used to its theoretical full capacity, the existing infrastructure for E15 and E85 can dispense higher volumes of these fuels than we have projected in this rule. Similarly, if all the vehicles that can use E15 and E85 exclusively used these fuels, we would project much higher volumes of ethanol consumption in 2026 and 2027. However, the available data to date has demonstrated that actual sales of E15 and E85 are far lower than theoretical maximums based on the capacity of existing infrastructure or compatible vehicles alone. Historic sales data for E15 and E85, which is the basis for EPA's projection of the future sales of these fuels, are discussed in greater detail in RIA Chapters 7 and 8.

Some commenters claimed that higher incentives for ethanol consumption, including potentially higher D6 RIN prices and the changes in the 45Z credit, could or would result in increased investment in the infrastructure necessary to sell E15 and E85 and/or greater sales volumes from stations offering these fuels. To explore the potential impact of greater incentives on E15 and E85 sales volumes, EPA considered the relationship between D6 RIN prices and the discount between the wholesale prices for ethanol (after accounting for the RIN value) and gasoline and the average per station sales of E15 and E85. We found that while the average annual sales of E15 (nationwide) and E85 in California have been modestly increasing over the past decade, there was no relationship between these sales volumes and D6 RIN prices or the average discount of ethanol relative to gasoline.[37] There are multiple potential explanations for the lack of correlation between these factors, including a lack of competition for these fuels at the retail level (enabling the retailers to retain more of the potential discount) and a resistance for some customers to purchase higher-level ethanol blends regardless of the retail discount.

With regards to the commenter's infrastructure claims, we discuss the constraints on E15 use related to distribution and retail infrastructure in RIA Chapter 8.4. Notably, while the applicable standards under the RFS program could theoretically provide some incentive for retail station owners to upgrade their equipment to offer E15, there is little direct evidence that the RFS program has operated in this capacity in the past. We acknowledge that there have been efforts to increase the infrastructure supporting ethanol distribution such as E15 replacement, which is the upgrading of retail station equipment (*e.g.*, pumps and storage tanks) to replace all sales of E10 with E15. However, these efforts have been relatively small in regard to total ethanol sales estimates and EPA does not have sufficient data on their impact. For this reason, we continue to rely on data representing number of stations providing higher-level ethanol blends and throughput data to estimate volumes of E15 and E85.

As described in previous responses, EPA revised its projection of ethanol consumption in this final rule using updated data, which resulted in significantly larger projected ethanol volumes in 2026 and 2027. While these volumes are not as large as the volumes that the commenter argues for, they are nonetheless significant increases over the projected volumes in the Set 2 proposal. EPA believes that its projected volumes are more indicative of what actual expected ethanol consumption will be in 2026 and 2027, rather than the speculative potential volumes claimed by the commenter.

Comment:

A commenter asserted that EPA is not statutorily required to consider consumption when setting the proposed volumes for the implied conventional biofuel requirement, adding that over 15 billion D6 RINs were generated in 2016, 2017, and 2018 and over 14.8 billion RINs were generated in 2015, 2019, 2023, and 2024. The commenter requested that EPA reject requests to limit the implied conventional biofuel requirement based on consumption.

Response:

As discussed in the prologue to RIA Chapter 7, while consumption is not an explicit factor that we must consider under the statute, it is inherent in the requisite consideration of infrastructure and cost to consumers of transportation fuel. Without any consideration of consumption, it is possible that the standards we set would be unachievable due to infrastructure constraints and/or exceedingly costly.

We also note that the RIN generation numbers cited by the commenter do not reflect the number of RINs available to the obligated parties to meet their compliance obligations. From 2015–2025,

[37] Additional analysis of the correlation between these values can be found in the memorandum, "Comparison of D6 RIN Prices, the Price of Ethanol Relative to Gasoline, and Higher-Level Ethanol Blend Sales," available in the docket for this action.

approximately 300–500 million D6 RINs were retired by parties that exported renewable fuel. While RINs were generated for this fuel, it was ultimately not used as transportation fuel in the U.S. and therefore these RINs were not available to refiners and importers of gasoline and diesel to meet their RFS obligations.

In this final rule we are establishing an implied volume requirement for conventional renewable fuel for all years at 15 billion gallons, a volume that is significantly higher than the volume of ethanol consumption that we project will occur. We are therefore not limiting the implied conventional volume to the volume of ethanol we project will be consumed in the U.S. in these years. While we expect that the difference between projected ethanol consumption and the implied volume requirement for conventional renewable fuel will be met primarily with BBD, the standards do create an incentive for higher volumes of ethanol consumption than we have projected if the market so chooses.

Comment:

A commenter presented analysis based on historical data on U.S. corn acreage (as reported by USDA), U.S. ethanol production (as reported by EIA), and inflation metrics (as reported by the Bureau of Labor Statistics) from December 2007 through 2024. The commenter discussed that the analysis neither relies on increasing corn planting nor diverts corn from other domestic demands to grow ethanol production. The commenter also stated that the analysis incorporates the continuous improvement in the productivity of U.S. farmers and the steady increase in the conversion efficiency of U.S. ethanol plants, trends which the commenter expects to continue for several years.

Response:

EPA acknowledges that it is possible for ethanol production and consumption to increase without increasing corn planting or diverting corn from other end uses. For example, the U.S. could increase domestic ethanol consumption by decreasing ethanol exports, by increasing productivity on existing corn acreage, or by increasing the efficiency of ethanol production.

5.4 Methodology for Projecting Consumption of Ethanol

Comment:

Several commenters expressed support for EPA to incorporate the latest data from AEO2025 and current information on RIN generation and carryover RINs in the final rule. A couple of commenters requested that EPA reconsider the proposal's "overly cautious" assumptions for projected ethanol consumption.

Response:

In this final rule, EPA uses the most up-to-date information available. This includes updated projections of the number of available carryover RINs that account for the 2025 SRE Decisions Actions and compliance with the 2024 RFS standards, as described in Preamble Section III.F and RIA Chapter 1.8. This also includes incorporation of updated projections from AEO2025 throughout the analyses for this final rule.

Comment:

A commenter criticized several aspects of EPA's methodology for estimating ethanol demand, including that:

1. EPA individually estimated demand for E0, E15, and E85 but did not indicate whether it adjusted the estimated physical volumes for the different energy contents of the respective fuels.

2. EPA did not consider the impacts of changes to RVP regulations in eight Midwest states, which would remove a substantial barrier to year-round sales of E15 in applicable states.

3. EPA ignored the substantial capacity to grow E15 and E85 throughput at existing sites based on a more supportive regulatory environment.

4. EPA used data sources to estimate the number of E0, E15, and E85 stations and their average throughput that may overestimate E0 demand if they include non-applicable retail sites.

5. EPA's forecasts of E15 and E85 station counts are based on extrapolations of 2021-2023 growth trends, which the commenter argued ignores the substantial role of RIN prices in driving E15 and E85 sales.

Response:

In this final rule, EPA implemented a "bottom-up" method to project ethanol consumption volumes by back calculating E10 volumes using the Agency's volume blend calculations (E0, E15, and E85) and the projected total energy content of gasoline consumption from AEO2025 Table 2. This differs from the approach in previous RFS rules where EPA use the physical volumes of gasoline consumption from AEO2025 Table 11. More information on each individual blend calculation can be found in RIA Chapter 7.5.

EPA acknowledges that the E15 and E85 markets are continuing to develop and the Agency has used the best data available to base our projection in this final rule. The RFS program does provide some incentive for the consumption of higher-level ethanol blends. For the purposes of analyzing the impacts of the 2026 and 2027 volume requirements, EPA projected an ethanol consumption volume that the Agency believes is representative of what could occur in this timeframe. This projection includes growth in the use of both E15 and E85.

While there is very limited data on the availability of E0 and the associated stations and throughput, EPA added additional E0 station data into its extrapolation for 2026 and 2027 for this final rule. More information on EPA's methodology and data sources is available in RIA Chapter 7.5.

Comment:

A commenter argued that EPA's method for projecting ethanol usage ignores the RFS program's market-forcing power to support significant potential for growth using existing infrastructure in response to heightened demand. The commenter discussed that EPA's use of historical average throughput treats the demand for E15 and E85 as flat and fixed, with throughput estimates reflecting utilization rates of only 12%, 5%, and 34% for E15, E85 outside California, and E85 in California, respectively.

The commenter argued that these assumptions contradict the theory of the RFS program, which is that raising RFS standards ultimately increases the availability and purchase of higher blends by shifting RIN demand and prices and cross-subsidizing industry investment. The commenter also expressed concern that EPA treats California, which experiences high E85 sales, as an aberration rather than as a model or proof of concept that demonstrates that the market will respond when government policies create incentives. The commenter noted that the RFS program is an available policy to achieve the same economic pressure for E85 and E15 nationally, as Congress intended.

Response:

The RFS standards have provided incentives for increased use of ethanol usage in the past and are expected to continue doing so. However, increases in E85 and E15 use have been modest to date. The use of E85 could be expected to increase if the price discount of E85 in comparison to E10 increased and if E85 were a more economical means of achieving the RFS standards than other options. This is the case for California, making it somewhat of an outlier compared to the remainder of the nation. However, we have received no new analysis of the E85 price discount that would occur under the influence of higher RFS volume requirements. As discussed in RIA Chapter 1.7.2, D6 RIN prices have been relatively high since 2013, providing a considerable incentive for increasing volumes beyond the E10 blendwall. Nevertheless, E15 and E85 consumption has risen at a steady but slow rate since 2012.

Thus, while higher RFS standards may directionally incentivize higher ethanol use, it is unclear to what extent such volumes would actually materialize. Since the RFS program does not require the use of ethanol, the market will determine whether compliance with the applicable standards beyond the E10 blendwall will occur as a result of increased E85 and/or E15 use, or primarily through the use of non-ethanol renewable fuels such as biodiesel and renewable diesel as has occurred historically.

Comment:

A commenter provided a detailed assessment using three different approaches to determine the real-world maximum potential corn ethanol production in 2026 and 2027: historical maximum, previous year, and potential expansion. The commenter noted that the highest year of ethanol production was 2024, when 16.22 billion gallons of ethanol were produced domestically, which the commenter argued does not account for the continuing growth in the productivity of U.S. corn growers or the steady improvements in the efficiency of U.S. corn ethanol plants.

The commenter presented historical U.S. corn production data showing U.S. corn yields have increased 1.6 bushels per acre each year from 153.3 bushels in 2008 to 179.3 bushels per acre in 2024. Based on this trend, the commenter projected yields of 180.9 bushels per acre in 2025 and 182.6 bushels per acre in 2026. The commenter also noted that the average annual corn plantings from 2008 through 2024 was 90.9 million acres, which is below the 93.5 million corn acres planted in 2007.

The commenter further discussed that yields have increased at a rate of over 0.0128 gallons of denatured fuel ethanol per bushel of corn each year from 1986 through 2024, and this rate has accelerated to over 0.0270 gallons of denatured fuel ethanol per bushel of corn each year from 2008–2024. The commenter attributed these increases to innovation enabled by growing industry operating experience and steady improvements in both the engineering designs of ethanol plants and the efficiency of the fermentation process. Extrapolating the long-term trend, the commenter estimated that the reported industry-average ethanol yield of 2.943 gallons of ethanol per bushel of corn in 2024 would increase to 2.969 gallons of ethanol per bushel in 2026 and 2.981 gallons per bushel in 2027.

Assuming that U.S. farmers would harvest 91.1% of 93.5 million acres of corn planted in the spring of 2025 and again in the spring of 2026, the commenter estimated 85.1 million acres would be harvested in fall 2025 and fall 2026. Applying their projections of bushels-per-acre yields for 2025 and 2026, the commenter estimated achievable corn crops of 15,402 million bushels in 2025 and 15,547 million bushels in 2026. After accounting for corn imports, exports, and domestic demand for non-ethanol uses, the commenter estimated that 5,622 million bushels of corn could be used to produce 16,691 million gallons of ethanol in 2025/2026, and 5,819 million bushels could be used to produce 17,357 million gallons of ethanol in 2026/2027.

Response:

EPA acknowledges that domestic corn production capacity and ethanol production capacity have increased domestically in recent years. A review of corn cropland and crop yield demonstrates that bushels per acre have increased each year while the total acreage of corn cropland planting has decreased. This decrease in crop planting is likely due to the increased crop yields and therefore less land is needed to achieve the same yield. Additionally, ethanol production has reported increases in yield of ethanol produced per bushel of corn at production facilities. With industry experience and advancements in technology, production efficiency has increased and led to these higher yields.

With assumptions of increased corn yield and efficiency in ethanol plants, increased production of ethanol is very likely to occur in 2026 and 2027. However, ethanol production uncertainties such as exports and diversion for alternative uses remain. Thus, EPA maintains its ethanol consumption analysis in RIA Chapter 7.5.

Comment:

A commenter noted that RIN prices and tax incentives will create significant incentives to further develop E15 infrastructure, which will increase E15 demand and reduce the need for BBD to backfill the implied conventional mandate. The commenter acknowledged that infrastructure development may not occur in the two years covered by this proposed rule, but argued that it should be considered in future rules.

Response:

EPA acknowledges that E15 demand has steadily increased in recent years and has accounted for this growth in its ethanol projections. The projections in this final rule use updated data compared to the Set 2 proposal, and we anticipate that projections in future rules will use the latest available data at the time of the rule, including developments in E15 infrastructure.

6. Proposed Volumes

6.1 Proposed Volumes for 2026 and 2027

Comment:

EPA received a number of comments supporting our proposal to establish RFS volume requirements for two years (2026 and 2027) in this action. Commenters provided a variety of justifications for establishing volumes for two years.

One commenter stated the multi-year nature of the Set 2 Rule provides certainty for obligated parties to plan for the future. One commenter stated that EPA's implementation of multi-year volume requirements for 2023–2025 in the Set 1 Rule has avoided the uncertainty of proposed changes from one year to the next. The commenter stated that uncertainty of annual rules made planning for compliance or investments more difficult and caused fluctuations in RIN prices. The commenter also mentioned that the statutory deadline for promulgating 2027 volume requirements is in 2025, further supporting the two-year window. The commenter concluded that having the rule for the next two years balances stability and flexibility, benefiting both renewable fuel producers and obligated parties.

A couple of commenters supported the two-year cadence because it balances lead time for regulated entities and EPA's ability to make adjustments if projections were incorrect or if external factors negatively impacted the market. The commenter noted that while there were outside factors that caused uncertainty in the market and negatively impacted renewable fuel production in 2025, setting final RFS volumes as they described would help provide greater certainty and stability.

Similarly, another commenter stated that EPA should announce volume requirements on a two-year rotation due to the anticipated growth in crush capacity and overall renewable fuel production. The commenter stated that a biennial schedule provides greater predictability and enables EPA to make informed decisions based on current and future production capacity. The commenter stated that extending the timeline between announcements creates an unnecessary risk that fails to account for new biofuel plants that come online after a specific rule is set, limiting the program's responsiveness to market developments. Another commenter also supported limiting the rulemaking to 2026 and 2027, citing numerous uncertainties identified in the proposal. The commenter stated that this timeframe would be appropriate to get the program back on track from a timing perspective. The commenter cautioned against setting volume requirements beyond 2027, given EPA's refusal to adjust volume requirements due to underestimates of what the industry can do and EPA's proposal to use an entirely new and unproven approach to estimate D3 RIN generation for RNG.

Response:

Consistent with the proposed rule, EPA is finalizing the RFS volume requirements for two years (2026 and 2027) in this rule. Establishing volumes for two years allows EPA to balance a desire to provide longer term certainty to the market (relative to establishing volumes for a single year) and the uncertainty inherent in projecting renewable fuel production and use into the future, especially for fuels projected to be produced from emerging technologies. The current uncertainty in the renewable fuels marketplace, resulting largely from a transition from blender to producer tax credits along with substantive changes to national trade policy, yields further support to a shorter time horizon for renewable fuel volume requirements at this time than was established in the Set 1 Rule (2023–2025). As these market uncertainties abate, it may again be appropriate for EPA to consider establishing renewable fuel volume requirements for a longer time period. We also recognize that the statutory deadlines for 2026 and 2027 have passed, and establishing volumes through 2027 in this rule allows EPA to get back on the timeline proscribed by Congress.

Comment:

Several commenters expressed support for increased RFS volumes. A few commenters stated that the volume of renewable fuel produced in 2024 exceeded the 2024 volume requirement, indicating that the market can support increased volumes for 2026 and 2027, but urged EPA to consider the impact of the proposed import RIN reduction provisions in the final volume requirements. A few commenters supported the volume requirements because they strengthen domestic industries associated with renewable fuel production. One commenter claimed that domestic feedstock and biofuel production could not only meet but exceed the proposed volume requirements, while another commenter stated that the proposed volume requirements adhere closely to the market's capacity to consume biofuel.

A couple of commenters supported the proposed increases to the volume requirements for 2026 and 2027 because they reflect continued growth in renewable fuel production and drive demand for domestic feedstocks. Other commenters supported the proposal's goals of increasing renewable fuel use and sending strong market signals.

Response:

The volume requirements we are finalizing for 2026 and 2027 in this action represent significant increases relative to the volume requirements established for 2023–2025 in the Set 1 Rule. In establishing these volumes, we have considered actual renewable fuel production in 2024 and 2025, as suggested by the commenters. We expect that the volume requirements for 2026 and 2027 will provide strong support for both feedstock producers and renewable fuel producers. As discussed further in Preamble Section III and in greater detail in the RIA, we have considered these benefits alongside the other statutory factors in determining the final volume requirements for 2026 and 2027.

Comment:

A commenter supported the proposed volume requirements, characterizing them as the highest volume requirements to date. The commenter stated that the proposed volumes resulted in an effective conventional renewable fuel requirement of 15 billion gallons, which they stated was the minimum obligation level EPA should set.

Response:

Consistent with the proposed volume requirements for 2026 and 2027, the volume requirements we are finalizing in this rule are the highest ever established under the RFS program. The final volume requirements also retain the proposed 15-billion-gallon opportunity for conventional renewable fuel to contribute towards meeting the volume requirements in 2026 and 2027.

Comment:

One commenter argued that EPA should set the volume requirements to the maximum achievable level that yields congressionally desired outcomes, such as increasing the use of renewable fuel in transportation fuel over time, increasing energy independence, and bolstering domestic agricultural markets. The commenter cited historical volume requirements and further argued that Congress intended the RFS program to increase the use of renewable fuel by substantial amounts annually, not small increments.

Response:

As described in the Preamble Section II, the CAA provides EPA with discretion to weigh the statutory factors and did not specify any particular emphasis on one statutory factor over the others. Notably, Congress could have required that EPA set the volume requirements at the maximum achievable level, but instead required that EPA assess multiple factors when setting the volume requirements. We find that we are reading the various statutory provisions relating to EPA's action in setting the volume requirements for years beyond those provided in the statutory tables cohesively, such that we provide meaning to each of the statutory factors. Our final rule properly gives meaning to each of the provisions—we have assessed each of the statutory factors, including "expected annual rate of future commercial production." We have set volume requirements at levels that support increased renewable fuel production and use but also give proper consideration to the projected adverse impacts of increasing renewable fuel production and use, such as higher costs.

Comment:

A few commenters, in opposition to the proposed volumes, stated that the required volumes must be achievable and aligned with the statutory requirements of the RFS program. A commenter argued that several aspects of the proposed rule unnecessarily increase costs and increase reliance on foreign fuels and imported feedstocks without providing additional benefits to consumers, domestic agriculture, domestic fuel producers, or the environment. Another commenter argued that the proposed volumes are inconsistent with the goals of the RFS program and emphasized the conflict between increased imports and energy security. The commenter stated that EPA did not have the tools to assess the interplay between imports, energy security, and independence and should reconsider its volume requirements.

A commenter claimed that the volume requirements are unattainable and will impact fuel prices, future biofuels production, and energy security. One commenter stated that the proposed volume requirements will drive imports of fuels and feedstocks, undermining EPA's energy security claims. A couple of commenters stated that EPA must reduce the proposed volume requirements, grant SREs, and mitigate burdens on regulated industries.

Response:

The applicable volumes, including the SRE reallocation volumes, that we are finalizing for 2026 and 2027 are achievable. EPA has assessed the market's ability to produce and consume renewable fuel in these years taking into account potential constraints on the production, import, and use of renewable fuels. For example, we have considered domestic production capacity (which could limit the supply of renewable fuel) as well as limits related to infrastructure that may restrict the quantity of renewable fuels that can be used as transportation fuel. This analysis is presented in detail in RIA Chapter 7. Based on this analysis, we have determined that the volume requirements we are establishing for 2026 and 2027 could be supplied by domestically produced renewable fuels. We are not, however, disqualifying or discounting imported renewable fuels from generating RINs in the RFS program. If the domestic supply of renewable fuel falls short of the required volumes, or if imported biofuels can be supplied to U.S. markets more cost effectively than domestic renewable fuel, these imported biofuels can supplement the available supply of domestic renewable fuels. Contrary to the commenters' statements, in establishing volume requirements for 2026 and 2027 that can be met with domestically produced biofuels, we expect that this rule will result in the intended benefits to domestic biofuel producers, domestic agriculture, energy security, and the environment. We also note that we anticipate that the SRE reallocation volumes will be met using available carryover RINs. As described in Preamble Section VII, our 70% reallocation of 2023–2025 exempted RVOs will retain the availability of some carryover RINs and thus they will remain available as a compliance flexibility for obligated parties should unanticipated shortfalls in the market occur.

We recognize that the 2026 volumes are partially retroactive. Nevertheless, we have sought to mitigate the burdens on obligated parties as described in Preamble Section II. The 2023 volume requirements, finalized in the Set 1 Rule, were finalized in June 2023. In that action, we evaluated renewable fuel production data through March to determine whether the market was on track to supply the renewable fuel volumes required. Given the timing of this action, we are unable to estimate renewable fuel production data. Nevertheless, we have used the most up-to-date information to evaluate renewable fuel supply and conclude that the volumes are achievable. Additionally, given that we are promulgating the 2026 standard early in the compliance year, the renewable fuel producers and obligated parties have additional time to adjust to the standards we are promulgating today, such that the retroactivity is minimized.

Comment:

One commenter suggested that EPA set a total renewable fuel volume that utilizes at least 80% of U.S. lipid-based production capacity.

Response:

As discussed in the previous response, and in greater detail in RIA Chapter 7, we project that the volumes we are setting for 2026 and 2027 in this action can be entirely with renewable fuels produced in the U.S. Meeting the entire volume of BBD we project will be supplied to meet the volume requirements in 2026 and 2027 in this rule with domestically produced BBD would require the exiting domestic BBD production facilities to operate at approximately 90% of their nameplate capacity in these years. This rate is higher than the 80% utilization rate requested by the commenters. To the degree that domestically produced biofuels are not available to meet the volume requirements, there are other alternatives available to obligated parties to meet their RFS obligations. One potential alternative, should the supply of domestic renewable fuels be insufficient to meet the volume requirements, is to import qualifying renewable fuels. Historically imported renewable fuels have provided a small but not insignificant portion of the overall supply of renewable fuels to the U.S. Obligated parties can also rely on other compliance flexibilities, such as the use of carryover RINs and the deficit carryforward provisions in the RFS regulations.

Comment:

A couple of commenters suggested that EPA use the latest data to project volume requirements for 2026 and 2027 and criticized EPA for relying on limited data and not reflecting existing Federal policy and market changes.

Response:

EPA has updated its analyses in this final rule using the most recent data available at the time the analyses supporting the final rule were completed. Notably, we have used AEO2025 instead of AEO2023 (which was used for the Set 2 proposal) and have considered the volumes of renewable fuels supplied to the U.S. in 2024 and 2025. We have also considered the potential impact of the changes to the 45Z credit included in OBBB.

Comment:

Many commenters stated that the proposal exceeds current domestic production and restricts global feedstocks, raising fuel costs for consumers. Another commenter stated that there is limited feedstock available to renewable fuel producers, so higher mandates will only increase pressure. The commenter recommended that EPA reduce the mandates to ensure obligated parties can continue to operate.

Another commenter recommended that EPA set annual volumes for each year no higher than the agricultural commodity market can supply both biofuel and food sector needs. The commenter noted that increased prices for U.S. crops can increase demand for foreign substitutes with potentially negative environmental impacts, like palm oil.

One commenter opposed the proposed volumes because it causes market distortions, increase food costs, and incentivizes converting natural lands into croplands to meet the program’s demands.

Response:

Our analysis in RIA Chapter 7 indicates that, contrary to the commenters claims, all the renewable fuel volume requirements we are finalizing for 2026 and 2027 can be met with biofuels produced in the U.S. Meeting the required volumes for these years with domestically produced biofuels will very likely require the use of imported feedstocks, particularly for BBD, after accounting for the projected production of qualifying feedstocks and the projected demand for these feedstocks in other non-biofuel markets. We expect that the volume requirements we are finalizing in this rule will increase the demand for domestically produced vegetable oils and lead to increased investment in domestic oilseed crushing capacity. While it is possible that increased demand for vegetable oils could result in an increase in the production of oilseeds in the U.S., approximately 40% of the soybeans produced in the U.S. are currently exported. If U.S. oilseed crushing capacity expands in the future, it is possible that the domestic production of soybean oil could increase through decreasing soybean exports rather than increasing cropland used for soybean production.

In this rule we are not finalizing the proposed import RIN reduction provisions. We still believe that reducing the number of RINs generated for imported renewable fuels and renewable fuels produced from foreign feedstocks would be consistent with the statutory intent of the RFS program and would increase its domestic benefits. We recognize, however, that finalizing the proposed import RIN reduction without adequate notice and opportunities for the vegetable oil markets to adjust could result in market disruptions and cause higher food prices. To minimize these potentially disruptive impacts, we are not finalizing the proposed regulations in this rule, but we intend to finalize import RIN reduction provisions in a future action.

Comment:

A commenter expressed concern about EPA's statement that because "the CAA does not state what weight should be accorded to the relevant factors, it gives EPA considerable discretion to weigh and balance the various factors required by statute." The commenter contended that the CAA actually constrains EPA's discretion substantially to ensure that EPA's implementation of the Set furthers Congress's market-forcing purpose. The commenter acknowledged that Congress "did not pursue its purposes of increased renewable fuel generation at all costs," but argued that the Set factors and the broader statutory structure convey to EPA when the market-forcing policy is too much.

Response:

When balancing the various statutory factors to determine the required volumes for 2026 and 2027, EPA has taken into consideration the broad goals of the RFS program to increase the production and use of renewable fuels and increase energy independence and security. These volumes represent a holistic balancing of the statutory factors, with these broad statutory goals in mind.

Comment:

One commenter proposed that EPA use its 2026 volume requirements for 2027 and retain the 2025 requirements for 2026 in order to give the market time to adapt.

Response:

Establishing volume requirements in the manner suggested by the commenter would be inconsistent with the statutory goals of the RFS program. Further, doing so would forego many of the benefits to statutory factors such as rural economic development, jobs, and energy security that are projected to result from the increase in the production and use of renewable fuels in these years.

In determining the appropriate volume requirements for 2026 and 2027 in this rule, we have considered the market's ability to respond to the volume requirements. While we recognize that we are finalizing this rule in 2026, the Set 2 proposal was issued in June 2025 and provided advanced notice to stakeholders of the potential for significantly higher renewable fuel volume requirements in 2026 and 2027. As discussed in Preamble Section II, we have considered the late and partially retroactive nature of the 2026 volume requirements. The final volumes for these years consider the potential constraints in the production and use of renewable fuels. We projected that the domestic biofuel industry is capable of increasing renewable fuel production throughout 2026 and 2027 and supplying the required volumes from renewable fuel production facilities that are already operational. In the event that domestic biofuel production falls short of the required volumes, there are other avenues for obligated parties to meet their RFS obligations, including the use of RINs generated for imported renewable fuels, carryover RINs, and the deficit carryover provisions.

6.1.1 Proposed Cellulosic Biofuel Volumes

Comment:

EPA received a number of comments expressing support for the proposed cellulosic biofuel volume requirements for 2026 and 2027. The commenters also expressed support for EPA's recognition that cellulosic ethanol from CKF could contribute to a higher cellulosic biofuel volume requirements in future years. Another commenter added that the proposed cellulosic volumes incentivize the market to continue development and investment in new technologies.

Response:

EPA appreciates the commenters' support for the proposed cellulosic biofuel volumes. In establishing the final volume requirements for 2026 and 2027, EPA considered the available data regarding production capacity, fuel consumption, vehicle market trends, and the statuary factors outlined in the CAA. Regarding the inclusion of CKF ethanol, as discussed in RIA Chapter 7.1.5, EPA continues to recognize the potential for this fuel to contribute to the cellulosic biofuel pool.

Comment:

Commenters broadly argued that the proposed 2026–2027 cellulosic biofuel targets are too low and represent a step backward compared to 2025, failing to support "steadily increasing production." They emphasized that RNG output has grown substantially over the past decade, yet the proposed volumes sit well below the sector's demonstrated and potential production.

Many disputed EPA's view that the proposed volumes would spur investment, contending instead that the levels are insufficient to provide the certainty needed to protect existing investments and drive technological innovation. They also warned that setting the cellulosic biofuel volume requirements too low undermines Congressional intent and the goals of the RFS, urging a long-term policy that fully accounts for and enforces available RNG volumes to incentivize industry growth.

One commenter added that regulatory delays, misguided statutory interpretations, and over-regulation undermine incentives to invest in the transportation fuel market.

Some commenters said the proposal underestimates sector momentum, including expected growth in CKF adoption, ongoing technological improvements, and the number of projects likely to be operational in 2026–2027. They cautioned that this underestimation risks stalling further investment.

Response:

EPA disagrees with the characterization that the final volume requirements represent a step backward or an underestimation of the industry's momentum. While EPA acknowledges the significant growth in the RNG sector and the potential for increased CKF adoption, the Agency's statuary obligation requires a complete view of the market that extends beyond theoretical production capacity.

EPA believes the final volume requirements, slightly higher than proposed, strike a neutral stance between ambition and achievability and provide market certainty to support continued investment and innovation in cellulosic biofuels. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic volumes such that we do not anticipate needing to waive the volumes under CAA section 211(o)(7)(D). To achieve this, our methodology for projecting cellulosic biofuel volumes is not based solely on the number of operational facilities or their maximum output. Instead, we have chosen to evaluate the historical and projected consumption of renewable CNG/LNG in the transportation sector. Because RINs generated for renewable CNG/LNG cannot be separated and used by obligated parties to demonstrate compliance with their RFS obligations until the renewable CNG/LNG is actually used as transportation fuel, setting volume requirements based on production alone, without considering consumption, would create a risk of a supply shortfall and would be inconsistent with CAA section 211(o)(2)(B)(iv).

Comment:

Commenters highlighted significant impacts on landfill RNG, noting the sector's reliance on a stable, ambitious RFS framework. While 2024–2025 cellulosic targets supported expansion, financing, and long-term planning, the proposed 2026–2027 levels do not reflect the industry's 20–30% annual growth rate and introduce uncertainty that could lead to project delays, cancellations, and slower sector growth.

Commenters similarly stressed that the dairy RNG sector needs regulatory certainty and strong policy signals. They argued that near-flat volume requirements for 2026–2027 do not justify the large investments required, requested multi-year volume requirements that reflect demonstrated growth trajectories with mechanisms for upward adjustment, and asked EPA to clarify its methodology for projecting CNG/LNG consumption from dairy-derived biogas to ensure transparency and confidence.

Response:

As discussed in RIA Chapter 7.1.4.2, EPA recognizes the significant contributions and continued growth of the landfill and dairy RNG sectors. We acknowledge that these sectors have shown robust production momentum over the past decade and play a critical role in the goals of the RFS program. However, in establishing the final volume requirements, we must account for the distinction between total production capacity and the volume of fuel actually used as transportation fuel.

To achieve this, our methodology for projecting cellulosic biofuel volumes is not based solely on the number of operational facilities or their maximum output; instead, as shown in RIA Chapter 7.1.4.1, we evaluate the historical and projected consumption of renewable CNG/LNG in the transportation sector. Because RINs generated for renewable CNG/LNG cannot be separated and used by obligated parties to demonstrate compliance with their RFS obligations until the renewable CNG/LNG is actually used as transportation fuel, setting volume requirements based on production alone, without considering consumption, would create a risk of a supply shortfall. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic volumes such that we do not anticipate needing to waive the volumes under CAA section 211(o)(7)(D).

Consistent with our approach in the Set 1 Rule, we believe that our methodology for projecting cellulosic biofuel production and use in this final rule are consistent with a "neutral aim at accuracy." The methodology we have used to project cellulosic biofuel production is not one "in which the risk of overestimation is set deliberately to outweigh the risk of underestimation."[38] Nor are the cellulosic biofuel volumes we are finalizing in this rule aspirational. By finalizing cellulosic biofuel volume requirements that reflect realistic and neutral consumption trends, EPA provides a stable framework in which future waivers are not anticipated, lowering market volatility and supporting investment. EPA will continue to evaluate market conditions, compliance data, and stakeholder input on an ongoing basis to inform future rulemakings.

Comment:

A commenter stated that EPA has repeatedly confirmed the importance of having an adequate number of carryover RINs, and yet proposed cellulosic volumes for 2026 and 2027 that leave no margin for error, contrary to the RFS statute. The commenter argued that carryover RINs for each biofuel category, including cellulosic biofuel, should hover between 9–17% of the volume requirements, which would equate to 117–221 million cellulosic carryover RINs.

The commenter also acknowledged EPA's efforts to revise its methodology to establish cellulosic volume requirements but argued that the proposed volume requirements would likely require subsequent use of EPA's cellulosic waiver authority. The commenter stated that EPA's proposal overlooks uncertainties in market data, the lack of cellulosic carryover RINs, the continued effects of the 2023 carry-forward deficit, and the delayed 2024 compliance and attest deadlines. The commenter emphasized that EPA is required by law to set cellulosic volumes at a level it believes will not require use of the cellulosic waiver. The commenter asserted that EPA cannot treat CWCs as a penalty on obligated parties to address mandates beyond current cellulosic biofuel production.

In contrast, another commenter stated that setting the cellulosic biofuel volume requirements at expected future production levels could encourage demand growth for CNG/LNG and alternate pathways, and that EPA could use its waiver authority and CWCs to reflect market capacity in that compliance year. Another commenter similarly suggested EPA set a high cellulosic biofuel volume requirement and to use CWCs as an alternative compliance mechanism.

Response:

As discussed in Preamble Section II, given the various statutory constraints and provisions, EPA is establishing the cellulosic biofuel volume requirements for 2026 and 2027 at the "projected volume available," which EPA has consistently interpreted to mean the projected volume of

[38] *API* at 479.

qualifying cellulosic biofuel production. In doing so, EPA does not increase the volume to include carryover RINs, nor does it reduce the volume to account for RIN deficits that need to be fulfilled. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic volumes such that we do not anticipate needing to waive the volumes at levels that are not expected to require later reduction through a waiver under CAA section 211(o)(7)(D).

We also note that by not finalizing SRE reallocation volumes for cellulosic biofuel, the 2023–2025 exempted cellulosic RVOs have resulted in an increase in the number of available cellulosic carryover RINs.

Regarding commenters' support for our revised methodology to establish cellulosic volumes, we disagree with the assertion that the proposed volume requirements would likely require a subsequent cellulosic waiver. Based on the most recent data available at the time of our analysis and the assessments in Preamble Section III.A and RIA Chapter 7.1, we set the volumes at the projected amounts available in 2026 and 2027. Consistent with the statutory requirements, we do not expect these volume requirements will require a future waiver.

Finally, setting the cellulosic biofuel volume requirements at expected future production levels, without consideration of potential demand-side constraints, would not be setting the volumes at the projected volume available. As described above, EPA must set the applicable cellulosic biofuel requirement without the expectation that the Agency will need to use its cellulosic waiver authority. Accordingly, EPA does not believe that it is permissible to intentionally rely on future invocation of the cellulosic waiver authority in order to issue CWCs as an alternative compliance mechanism.

Comment:

Several commenters urged EPA to increase the proposed cellulosic biofuel volumes for 2026 and 2027, consistent with statutory language and Congressional goals. A couple of commenters argued EPA must finalize volumes that project production of CNG/LNG fuel based on at least a 20–25% growth rate, which would result in cellulosic biofuel volume requirements of 1.5 billion RINs or more in 2026 and 2027.

Response:

Consistent with EPA's analysis in RIA Chapter 7.1.4, we are setting the cellulosic biofuel volume at the projected volume available. Under CAA section 211(o)(7)(D)(i), this is the level to which EPA would reduce the cellulosic requirement if the Agency exercised its cellulosic waiver authority. This approach is also consistent with CAA section 211(o)(2)(B)(iv), which directs EPA to set cellulosic volumes at levels that are not expected to require later reduction through a waiver under CAA section 211(o)(7)(D). In light of this requirement under the statute, we do not adopt a production-only approach to setting cellulosic biofuel volume requirements; instead, we continue to consider both production and consumption of cellulosic biofuel. We will continue to evaluate market conditions, compliance data, and stakeholder input on an ongoing basis and consider adjustments to this approach in future rulemakings as appropriate.

Comment:

A commenter stated that the cellulosic biofuel volume should be set at zero gallons and should reflect the failure of cellulosic ethanol to materialize.

Response:

As detailed in RIA Chapter 7.1.5, we are projecting meaningful volumes of cellulosic ethanol from CKF in 2026 and 2027. Even so, the cellulosic biofuel category encompasses more than cellulosic ethanol, most notably renewable CNG/LNG, as described in RIA Chapter 7.1.1. Thus, we do not believe it is appropriate to set the cellulosic biofuel volume requirements based solely on projected cellulosic ethanol production volumes when additional qualifying cellulosic biofuels, such as renewable CNG/LNG used as transportation fuel, are expected in 2026 and 2027.

6.1.2 Proposed Non-Cellulosic Advanced Biofuel Volumes

Comment:

A few commenters expressed concerns regarding EPA's approach to setting required volumes for non-cellulosic biofuels, especially as they related to how much of the implied volume of conventional renewable fuel would be met by non-cellulosic fuels.

A commenter stated that EPA is significantly overestimating the amount of non-cellulosic advanced biofuels that will be needed to meet the implied conventional volume. The commenter noted that EPA projects 1.22 billion and 1.34 billion BBD and/or advanced biofuel RINs will be needed in 2026 and 2027, respectively, to meet the 15-billion-gallon implied conventional renewable fuel requirement. However, the commenter argued that U.S. ethanol consumption is projected by EIA to reach 14.5 billion gallons or more in 2026 and 2027 (with at least 14.3 billion gallons per year coming from conventional ethanol), which would significantly reduce the need for BBD and/or advanced biofuel RINs to fill the "conventional gap." The commenter concluded that more BBD and other non-cellulosic advanced biofuels will be available to meet 2026 and 2027 BBD and advanced biofuel standards than EPA is assuming in the proposal and thus the required volume should be raised.

Another commenter agreed, suggesting that that refiners can continue to utilize carryforward RINs or defer annual obligations to avoid using additional advanced biofuels. The commenter presented data showing that advanced RIN use for compliance did not exceed advanced biofuel volume requirements to backfill the total renewable fuel volume requirements for years 2020–2022, with only 2023 showing a positive difference.

Response:

The volumes finalized reflect an updated conventional gap required. The BBD required to meet the implied conventional volume is approximately 15 billion less 14.4 billion gallons of projected conventional volumes. Commenters are correct in assuming that BBD and other non-cellulosic advanced biofuels will be the available biofuels to meet the standard.

Comment:

Some commenters stated that EPA has consistently set the advanced biofuel volume requirement too low and that there are sufficient feedstocks to maintain the higher proposed volumes. Others suggested that the proposed volume requirement was still too low and should be increased to match production capacity. Another commenter stated that EPA should ensure sufficient volumes to support increased production of non-cellulosic advanced biofuel. The commenter noted that while EPA is proposing to increase the overall advanced biofuel volume requirement, the increase is largely based on its proposed increase for BBD. The commenter expressed concern that because EPA does not set the BBD volume requirements based on potential production, the majority of the non-cellulosic advanced biofuel volume is also likely to be met by BBD (and carryover D4 RINs), leaving no room for growth for undifferentiated advanced biofuels each year. The commenter argued that it is inappropriate to only consider historical volumes in light of the relative competitive advantage renewable diesel has had over other advanced biofuels. The commenter recommended that EPA ensure the overall advanced biofuel volumes are set to continue to support investments into additional fuels beyond BBD.

Response:

EPA has noted that production capacity is more likely than feedstock availability to be a constraining factor on domestic BBD production. The BBD volume requirements in this rule reflect that, as they are based on estimates of 90% production capacity utilization. Given this, the volumes are set based on potential production, meaning there is room for growth for undifferentiated advanced biofuels. EPA considers historical as well as forward looking data when evaluating volumes, production capacity, and production itself.

Comment:

A commenter suggested that EPA could lower compliance costs by setting a volume requirement that does not rely on just D4/D5 RINs and instead includes D6 RINs. Another commenter stated that EPA should set the volume requirement at the available supply, without consideration of any projected shortfall in the supply of conventional renewable fuel to remove any incentive to utilize D6 RINs and increase value of D4 RINs.

Response:

Doing as the commenter suggests may generate compliance costs, but abandons the required structure of a nested obligation that incentives advanced biofuels. The Energy Independence and Security Act of 2007 mandates nested, separate categories, and allowing D6 RINs to fulfill any shortfall would go against this requirement.

Comment:

Several commenters encouraged EPA to maintain at least the proposed annual growth rate, noting that certainty in policy is critical for maintaining market stability. A commenter suggested EPA set advanced biofuels volumes based on 2025 data and the exclusive use of domestic fuels and feedstocks to eliminate the need for imports. Finally, other commenters provided support for the increased volume requirements, without providing substantial feedback.

Response:

EPA is utilizing the latest available data, which is largely made up of partial or full-year data for 2025, for this final rule. EPA projects that much of the volume requirements will be met with biofuels produced from domestic feedstocks.

Comment:

One commenter stressed that EPA should minimize harm to consumers and taxpayers by setting volume requirements at levels that do not encourage additional production or consumption of food and feed-based biofuels that can distort other markets.

Response:

As discussed in RIA Chapter 9.4, the volume requirements in this rule are estimated to have very small impacts on food prices. EPA considered all required statutory factors and available technical data in establishing the volume requirements. As discussed in greater detail in RIA Chapter 7.2, biofuel feedstocks used to meet the volume requirements in this rule, especially for BBD, will not divert more than 20% of soybean oil feedstock destined for non-biofuel uses. Furthermore, any soybean oil diverted is easily backfilled with other eligible food grade oils, such as Latin American soybean oil or canola oil.

Comment:

A commenter argued that setting BBD and advanced biofuel volume requirements at levels at or close to the projected supplies counters the intent of Congress. The commenter stated that projected production capacity, representing what the industry can produce with the correct market-driving policy in conjunction with a favorable market environment, would be a better estimate for future volumes.

Response:

EPA has updated its analysis of BBD volumes to reflect changing market dynamics, given abundant BBD feedstock estimates. As a result, the BBD volume requirements in this rule are now based on production capacity, which is the assessed limiting factor of BBD production.

6.1.3 Proposed Biomass-Based Diesel Volumes

Comment:

Several commenters indicated their support for the proposed volume requirements for BBD. Commenters agreed with EPA's approach to setting the volume, taking into account the growth in BBD production capacity and availability of domestic feedstocks. Another commenter commissioned a third-party study by GlobalData to conduct a feedstock analysis to support market determinations pertaining to those available for food, feed, and fuel. The study, "The Outlook for Global Lipid Feedstocks to 2030," demonstrated that feedstock supply was not a constraint in achieving the proposed volumes and even higher volumes.

Response:

As discussed in RIA Chapter 7.2, EPA has incorporated information from the GlobalData report in its analyses and agrees that feedstock supply is not a constraint in achieving the final volumes.

Comment:

A few commenters encouraged EPA to set volumes that projected at least 80% utilization for BBD manufacturing, stating that a combination of foreign and domestic feedstocks and fuels was necessary to generate the number of RINs that obligated parties would need under the proposed rule to avoid harmful impacts to consumers and to support a strong fuel supply.

Response:

EPA has targeted 90% utilization for BBD manufacturing, given that the renewable diesel industry has achieved this rate in previous years and the abundance of feedstocks available to producers. See RIA Chapter 7.2 for further discussion of production capacity utilization.

Comment:

A couple of commenters provided industry data challenging EPA's assessment that domestic feedstocks alone were not available to meet proposed volume requirements and instead argued that there were ample production capacity and feedstocks available to support increased volume requirements. Some commenters expressed concerns that EPA's proposal might not "ensure" a minimum volume requirement is met and that stronger volume requirements would provide the industry with the support needed to grow. Another commenter discussed their support for the proposed volume requirements but noted that if the import RIN reduction provisions are not implemented and the outstanding SRE's are granted, the BBD volume requirements should be raised to ensure the volumes are being met by domestic production.

Other commenters expressed concerns about the availability of domestic feedstocks to meet the proposed volumes and requested that EPA set the volume requirements no higher than 2024 production levels. A commenter noted that EPA's own assessment showed that domestic production was insufficient to achieve the proposed volumes, so EPA's finding that production capacity was adequate to meet these volumes was only possible based on a large increase in vegetable oil imports for fuel and food uses. Other commenters agreed that a combination of domestic and foreign feedstocks would be necessary to meet the proposed volumes while supplying feedstocks for other demands. Another commenter claimed that EPA provided no legitimate basis for its projected 6.83-billion-gallon BBD requirement for 2026 in light of the import RIN reduction proposal and the recent changes to the 45Z credit.

Response:

While EPA believes that sufficient supplies of domestic feedstocks exist to satisfy the final volume requirements, the Agency acknowledges that this would require a large market shift from non-biofuel uses. However, EPA is not finalizing import RIN reduction provisions in this rule, allowing for continued, though less-incentivized, use of imported feedstocks in 2026 and 2027, including those not eligible for the 45Z credit. EPA has finalized the BBD volume requirements using production capacity, the assessed limiting factor of BBD production at this time.

Comment:

A commenter argued that EPA's proposed BBD volumes were arbitrary, stating that the DRIA provided little explanation for the rationale behind proposing BBD volumes at 600 million RINs below the non-cellulosic advanced biofuel volumes and that EPA relied on outdated information on RIN generation. The commenter continued their argument, stating that EPA incorrectly assumed that 2024 BBD volumes would be replicated, stating that this assumption contradicted current data and market dynamics, changes in the renewable fuels tax credits, and the provisions of the proposed rule.

Response:

EPA has assessed the current state of renewable fuel tax credits, feedstock supply, and market dynamics. Much of our data is now from 2024 or 2025. As a result, EPA is finalizing volume requirements based on the production capacity utilization of existing domestic BBD production facilities.

Comment:

A commenter expressed concern about EPA's proposal to increase the 2026 BBD volumes by 61%, despite RIN generation data showing production is significantly below the 2025 standard. The commenter cited a feedstock analysis by S&P to suggest that the proposed volumes cannot be met solely by domestic feedstocks and may require increasing imports.

Response:

While 2025 was a down year for BBD production, abundant feedstock supply and the robust volume requirements finalized in this rule provide far greater incentive for increased BBD production in 2026 and 2027 than in past years.

Comment:

A commenter stated that if EPA had fairly analyzed the statutory factors, the BBD volumes would not be increased, as the proposed volume requirements would add food and transportation costs for consumers and provide minimal environmental benefits.

Response:

EPA has analyzed all statutory factors and estimates only small increases in food and fuel costs as a result of the increased BBD volume requirements, while simultaneously continuing to increase rural employment and energy independence.

Comment:

Based on recent growth trends, some commenters suggested that EPA raise the volumes for BBD to account for a growing renewable jet fuel industry. Other commenters stated that at least 5.25–5.75 billion gallons of BBD should be required to provide market certainty and support market production capabilities.

Response:

Much of the current domestic renewable jet fuel production capacity is co-located with renewable diesel facilities. While EPA acknowledges the burgeoning renewable jet fuel industry, the Agency has largely relied on publicly available renewable diesel capacity numbers in order to set the final volumes of this rule. However, EPA will continue to monitor and evaluate the renewable jet fuel industry as it grows to a co-equal industry alongside the other BBD subsectors.

Comment:

A commenter suggested that EPA mandate that at least 2 billion gallons of the BBD volume requirements must be sourced from biodiesel to support the industry's growth.

Response:

Based on latest available EIA capacity numbers, EPA estimates biodiesel volumes will contribute 1.78 billion gallons annually to the BBD volume requirement. See RIA Chapter 7.2 for further discussion of BBD production.

6.1.4 Proposed Implied Conventional Renewable Fuel Volumes

Comment:

Several commenters expressed support for EPA's proposed implied conventional renewable fuel volumes of 15 billion gallons. One commenter further elaborated that the implied conventional renewable fuel requirement for 2026 and 2027 is not only consistent with the law and previous RFS rules but is also realistically achievable. Another commenter stated that the U.S. biofuel industry has more than enough capacity to meet the proposed volume requirements and that a shortfall in ethanol volumes is unlikely given records crop yields and the industry's history or oversupply.

A few commenters stated the proposed volume requirements will provide the ethanol industry with room for growth, including through adoption of higher-level ethanol blends. A few commenters discussed that the 15-billion-gallon standard provides certainty to markets to ensure stable corn prices, viability of family farms, growing rural economies, and competitiveness of producers in international markets.

A commenter stated that the proposed implied conventional volume requirements are supported by several factors, including that: E15 usage is expanding in the Midwest, more retailers are adopting E15 as a "drop in" replacement for E10, EPA has taken steps to reverse de facto electric vehicle mandates, automakers are introducing new flexible fuel vehicles (FFVs) capable of utilizing ethanol blends up to E85, and pending regulatory and legislative changes promoting E15 adoption. The commenter added that ethanol will likely fill more of the implied conventional blending over 2026 and 2027 than calculated in the proposed rule. Relatedly, a commenter expressed support for the proposed volume requirements and urged EPA to advance the use of higher ethanol blends in FFVs and encourage broad incentives for cellulosic ethanol and SAF.

A commenter stated that a proper review of the statutory factors supports the 15-billion-gallon standard for implied conventional renewable fuel for 2026 and 2027 and requested that EPA reject requests to lower volumes based on constraints on ethanol use.

Response:

EPA thanks commenters on their support for 15-billion-gallon conventional renewable fuel volume requirement. As shown in RIA Chapter 7.5, EPA's ethanol projections show that ethanol consumption is likely to be in the range of 14 billion gallons in 2026 and 2027. Although this is below the 15-billion-gallon conventional renewable fuel volume requirement, EPA believes that this is an accurate projection given trends in higher-level ethanol blends and gasoline consumption.

In RIA Chapter 8, EPA analyzes flexible fuel infrastructure for E85. Compared to about a decade ago, auto manufacturers are producing significantly fewer FFVs. The highest number of FFVs available remains in California, which is where the largest sales of E85 continue.

EPA projections for E15 and E85 are based primarily on publicly availability information, including historic trends data, throughput volumes, and station counts.

Comment:

A couple of commenters discussed that a consistent 15-billion-gallon conventional renewable fuel volume requirement will incentivize infrastructure investment and buildout. One commenter discussed that current ethanol production achieves capacity of 18 billion gallons, adding that consumption is limited by infrastructure and blending requirements rather than supply. A commenter urged EPA to consider ethanol as a larger part of the solution to providing Americans access to affordable fuels and support to American farmers.

Response:

We acknowledge that infrastructure constraints are still associated with E15 and E85 and may impact the consumption in 2026 and 2027. Ethanol production capacity in the U.S. reached about 16.5 billion gallons in 2025, which includes both domestic consumption and exports. This does leave room for continued ethanol growth should market changes occur in the future.

Comment:

One commenter suggested that EPA could utilize its statutory authority to set the implied conventional volumes even higher than 15 billion gallons to offset export market losses borne by American farmers and ethanol producers and to offset surplus BBD RINs from displacing corn ethanol use. Relatedly, another commenter discussed that the 15-billion-gallon conventional renewable fuel volume requirement would be an inequitable regulatory volume constraint not supported by industry trends in ethanol adoption. The commenter called U.S. ethanol the "strongest, most dominant, and most American" biofuel that is more relevant to an energy dominance agenda than other biofuels. The commenter suggested that expansion of the implied conventional volumes to increase volumes of all mature biofuels.

Response:

Our determination of the appropriate volume requirements to establish for 2026 and 2027 is based on all the factors that EPA is required to analyze under CAA section 211(o)(2)(B)(ii), not only the goal of the RFS program to increase the use of renewable fuels in the transportation sector over time. We have determined that the volume of corn ethanol that can be consumed in the U.S. is less than 15 billion gallons. Based on the many factors that we analyzed, we have determined that it would not be appropriate to increase the implied conventional renewable fuel volume requirement above 15 billion gallons in 2026 and 2027. Doing so would not be expected to increase the volume of conventional renewable fuel consumed, but rather require yet more advanced biofuel volumes to backfill for the shortfall in corn ethanol consumption, advanced biofuel volumes that would then be higher than we would consider to be appropriate when weighing the many factors.

Comment:

A couple of commenters expressed concern that the proposed implied conventional renewable fuel volumes are unrealistic or unachievable. One commenter requested EPA base the volume requirement on actual ethanol demand, claiming that there is no correlation between D6 RIN prices and ethanol blending. The commenter asserted that EPA's failure to establish a realistic conventional renewable fuel target is arbitrary, and the proposed volume of 15 billion gallons is well above what can be blended into the gasoline pool. Another commenter expressed concern that the 15-billion-gallon conventional renewable fuel volume requirement would increase volatility and unpredictability in the market.

A commenter noted that EPA conceded ethanol consumption has never reached, and is not expected to reach, 15 billion gallons, yet claimed a "market signal" was needed to promote its use. The commenter argued that Congress never intended to use the RFS program to drive midlevel ethanol blends, but rather likely intended to establish a floor for ethanol consumption. The commenter referenced the 2007 AEO, which Congress used to inform development of the RFS program, which estimated that the U.S. would consume 156 billion gallons of gasoline in 2015, implying a 9.6% ethanol concentration.

Additionally, the commenter argued that there is no valid reason for maintaining what they characterized as an "unattainable implied conventional mandate." The commenter states that it is economical (profitable) to blend ethanol into the motor gasoline pool as E10 without the RFS program, citing the DRIA's "No RFS Baseline" conclusion that it is economical to blend up to 10% ethanol into the entire gasoline pool. The commenter contended that despite the economic viability of virtually all ethanol produced, EPA is proposing to impose "crippling compliance costs" on consumers to increase ethanol consumption by just 0.1% rather than establishing a realistic implied conventional target.

A commenter expressed concern that the proposed conventional ethanol volume requirement exceeds practical infrastructure limits for current UST systems by effectively forcing E15 blends into the market. The commenter asserted that the proposed volume requirement should not amount to a de facto mandate to upgrade UST systems, adding that achieving universal E15 compatibility would require more than $1 billion in infrastructure investment. The commenter requested that EPA set the volumetric ethanol mandate to no more than 9.7% of projected gasoline demand.

Response:

Total ethanol consumption in 2026 and 2027 will exceed the E10 blendwall due to the projected increase in the consumption of higher-level ethanol blends, which are incentivized through the RFS program, as discussed in RIA Chapter 2.1.1. Nevertheless, total ethanol consumption is still projected to fall short of 15 billion gallons. We expect the market to rely on both ethanol and non-ethanol biofuels to meet the total renewable fuel requirement (including the implied 15-billion-gallon conventional renewable fuel portion finalized in this action).

With the exception of BBD, the standards under the RFS program are for biofuel categories generally distinguished by differences in GHG reductions and are not specific to any particular type of renewable fuel that qualifies under those categories. An implied volume requirement for conventional renewable fuel of 15.0 billion gallons does not create a requirement for the use of ethanol, nor does it create any requirement for retail service stations to offer E15 (or E85). Instead, the market will determine the mix of biofuels that are produced and consumed for purposes of compliance with the applicable standards. Retail service stations can choose whether or not to offer E15 independently of the standards under the RFS program, and we expect that they will do so only if it provides them with some economic advantage.

Comment:

A commenter estimated that a conventional renewable fuel requirement based on actual consumption capability would support a target of approximately 13.9 billion gallons in 2026 and 2027. The commenter added this volume requirement would help lower consumer cost by more than 50%, protect domestic refining jobs and fuel supplies, and incentivize lower carbon intensity biofuels. Another commenter similarly stated that EPA should accurately assess the amount of ethanol that can be blended into the domestic transportation fuel market and adjust the implied conventional and total renewable fuel volume requirements to be consistent with this value.

A couple of commenters discussed that a lower implied conventional volume would protect jobs and energy security. In contrast, a commenter expressed concern that the proposed volume requirement mandates more ethanol than can be physically blended at the current 10% ratio and that the volumes can only be satisfied through increased biofuel imports, contradicting energy security and affordability goals of the RFS program. The commenter stated that setting the implied conventional mandate according to actual demand would cut compliance costs in half.

A commenter expressed concern that the proposed volumes threaten the viability of independent refiners and other industries across the supply chain. Another commenter stated that by allowing total renewable fuel volumes to be met through the use of additional volumes of advanced biofuels, the proposed rule essentially allows for overcompliance with advanced biofuels to comply with the conventional volumes, but not vice versa.

Response:

These comments conflate the implied conventional renewable fuel volume requirement with ethanol. The two are not the same. Despite the fact that ethanol has been the predominant component of conventional renewable fuel, it is not the only component. Congress defined renewable fuel without reference to ethanol.[39] The statutory scheme thus plainly allows other renewable fuels, besides ethanol, to qualify as renewable fuel so long as they meet the statutory requirements.[40] EPA's regulations follow the same approach. Historically, other conventional renewable fuels, such as conventional biodiesel and renewable diesel, have been used in the U.S.

[39] CAA section 211(o)(1)(J).
[40] CAA section 211(o)(1)(J), (o)(2)(A)(i).

In establishing the volume requirements for years without statutory volumes, EPA is mandated to consider renewable fuels generally, not just ethanol.[41]

Also, there is no conventional renewable fuel standard under the statute. Instead, the implied conventional renewable fuel volume requirement is merely that portion of total renewable fuel that is not required to be advanced biofuel. Advanced biofuel, however, may be used to satisfy any portion of the total renewable fuel volume that is not required to be advanced biofuel (*i.e.*, the implied conventional renewable fuel volume requirement).[42]

Additionally, if the implied volume requirement for conventional renewable fuel were reduced below 15 billion gallons, it would be met entirely with domestically produced corn ethanol as current production capacity exceeds our projection of the E10 blendwall. There would be essentially no need for production or import of any other conventional renewable fuel. However, as described above, we have determined that it is not appropriate to set the implied conventional renewable fuel volume requirement below 15 billion gallons at this time, as it would be impractical to ignore the market effects caused by E15 and E85.

As described in Preamble Section III.E.4, we find it appropriate to set the implied conventional volume at 15 billion gallons to provide longer-term incentives for the market to invest in higher-level ethanol blends. As in the Set 1 Rule, we took into consideration the opportunities for higher-level ethanol blends such as E15 and E85 created by establishing an implied volume requirement for conventional renewable fuel that exceeds the E10 blendwall. While we acknowledge that most of the implied volume requirement for conventional renewable fuel that is above the E10 blendwall will be met with non-cellulosic advanced biofuel, a portion will be met with ethanol in the form of E15 and E85, and these blends would likely not be consumed if the implied volume requirement for conventional renewable fuel was not set above the E10 blendwall. We continue to believe that support for E15 and E85 is an important element of the RFS program.

Comment:

A commenter expressed concern that EPA's approach to setting the proposed volumes for ethanol and BBD applied a double standard in which a decrease in gasoline demand resulted in a decrease in proposed ethanol over the next 5 years but not BBD.

Response:

EPA acknowledges that ethanol consumption volumes are linked to gasoline demand, while BBD consumption is less connected to diesel demand. Thus, as gasoline consumption volumes fluctuate, ethanol volumes will fluctuate as well. However, BBD is generally a replacement for diesel and therefore is not as tied to its petroleum counterpart as ethanol is.

[41] See, *e.g.*, CAA section 211(o)(2)(B)(ii)(III) (requiring EPA to analyze "the expected annual rate of future commercial production of renewable fuels" generally, not just of ethanol).
[42] See CAA section 211(o)(1)(B)(i)(I), (o)(2)(B)(i)(II).

Comment:

A commenter argued that Congress likely intended to use the RFS program to establish a floor for ethanol consumption rather than drive midlevel ethanol blends. The commenter referenced AEO2007, used by Congress to inform development of the RFS program, which estimated an implied 9.6% ethanol concentration in 2015, up from an 8.2% concentration in 2007. The commenter discussed that in 2024 the historical nationwide concentration of ethanol in the gasoline pool was 10.30%, which EPA projects will fall to 10.27% and 10.29% during 2026 and 2027, respectively. The commenter presented data demonstrating the historical relationship and showing no correlation between D6 RIN prices and the ethanol blend rate. The commenter stated that EPA glosses over the history and market changes of the implied conventional renewable fuel program.

The commenter further argued that EPA's DRIA projects an overall decline in ethanol consumption relative to the 2025 baseline and that the proposal will lead to only modest increases of ethanol consumed through E15 and E85. The commenter noted that EPA anticipates incremental ethanol consumption through E15 and E85 to total approximately 150 million gallons combined in 2026 and 2027.

Response:

We note that EPA's projections of ethanol consumption has increased significantly since the Set 2 proposal as a result of updated projections in AEO2025. The majority of ethanol volumes in the U.S. are currently from E10. Although the estimated ethanol values were lower in the proposal than the final, this is mostly attributable to the change from AEO2023 to AEO2025, which projects a larger use of gasoline than the previous AEO. With this increase, we see a larger increase in total ethanol.

The volume of ethanol consumed in E15 and E85 is still relatively small compared to the volume of ethanol consumed in E10, as described in RIA Chapter 7.5. And although volumes of E15 and E85 have steadily increased in recent years, they have yet to drastically impact the overall ethanol totals. We suspect that increases in E15 volumes will continue to be incremental. Additionally, significant E85 volumes remain primarily in California. Until significant E85 volumes expand to the rest of the U.S., we expect that increases in E85 volumes will likely remain incremental as well.

With this in mind, total ethanol estimates remain on a level-to-slightly increasing trend and linked to gasoline consumption volumes.

Comment:

A couple of commenters requested that EPA set conventional volumes at the blendwall and reassign excess volumes to advanced biofuels and BBD to reduce compliance costs without sacrificing volumes.

Response:

In the Set 2 proposal, we projected that the majority of the conventional renewable fuel volume above the E10 blendwall would be made up with excess advanced biofuel (primarily soy biodiesel and renewable diesel) as it has in past years. Changing the volume requirements such that the implied conventional renewable fuel volume was at or below the E10 blendwall, with a corresponding increase in the advanced biofuel volume requirement, would be expected to result in a decrease in the use of corn ethanol in higher level ethanol blends and a corresponding increase in the use of advanced biofuel (most likely biodiesel or renewable diesel). However, total ethanol consumption will exceed the E10 blendwall due to the projected increase in the consumption of higher-level ethanol blends, which are incentivized through the RFS program. We expect the market to rely on both ethanol and non-ethanol biofuels to meet the total renewable fuel requirement (including the implied 15.0-billion-gallon conventional renewable fuel portion finalized in this action).

We recognize that implied conventional biofuel volumes that are above the E10 blendwall generally contribute to higher D6 RIN prices and implied conventional biofuel volumes below the E10 blendwall generally contribute to lower D6 RIN prices. As discussed in more detail in RIA Chapter 10, we also recognize that the volumes we are finalizing in this rule are projected to increase fuel costs. However, these program costs are not impacted by RIN prices. Because the RFS program operates as a cross-subsidy, lower D6 RIN prices would reduce the cost of the RFS obligation on petroleum-based fuels but at the same time would increase the effective price of ethanol by reducing the value of the RIN generated when qualifying ethanol is produced. Lower D6 RIN prices alone (assuming the same total renewable fuel volume) would not reduce the cost of the volumes in this rule or the overall impact of this rule on fuel prices (including both gasoline and diesel), though it would likely shift some of the price impact from diesel fuel to gasoline

Comment:

A commenter argued that the CAA requirement that EPA base volumes on its “review of the implementation of the program” should have led EPA to conclude that high implied conventional volumes have not increased E15 infrastructure adoption or use. The commenter argued that because the best reading of CAA section 211(o)(2)(B)(ii) requires EPA to set “applicable volumes” for “each” renewable fuel based on an analysis of statutory factors, and because *Loper Bright Enterprises vs. Raimondo* requires EPA to use the best statutory interpretation, EPA must reevaluate its approach to the implied conventional mandate.

Response:

EPA considered all required statutory factors and available technical data in establishing the volume requirements, including the implied conventional renewable fuel volumes. As described in the Preamble Section II, and noted in recent court cases, the CAA provides EPA with discretion to weigh the statutory factors and did not specify any particular emphasis on one statutory factor over the others. While Congress could have indicated how EPA was to weigh the various factors or specified only a single factor for EPA to consider when setting the volume requirements (*e.g.*, maximum achievable volumes), it did not. Instead, Congress required that EPA assess multiple factors when setting the volume requirements without stating how to weigh each factor. When balancing the various statutory factors to determine the required volumes for 2026 and 2027, EPA has taken into consideration the broad goals of the RFS program to increase the production and use of renewable fuels and increase energy independence and security. These volumes represent a holistic balancing of the statutory factors, with these broad statutory goals in mind.

We disagree with the commenter's assertion that the "best reading" of the statute requires EPA to set applicable volumes for conventional biofuel lower. As noted previously, there is no conventional renewable fuel standard under the statute.[43] Instead, the implied conventional renewable fuel volume requirement is merely that portion of total renewable fuel that is not required to be advanced biofuel. Advanced biofuel, however, may be used to satisfy any portion of the total renewable fuel volume that is not required to be advanced biofuel (*i.e.*, the implied conventional renewable fuel volume requirement).[44] Thus if more advanced biofuel is used than required by the 2022 advanced biofuel standard, then less than 15 billion gallons of conventional renewable fuel will be needed to meet the total renewable fuel standard. CAA section 211(o)(2)(B)(ii) refers to "each fuel specified in the tables;" but the tables refer not to conventional biofuel, but rather total renewable fuel, advanced biofuel, BBD, and cellulosic biofuel. We also note that CAA section 211(o)(2)(B)(ii) suggests EPA should consider renewable fuels generally.[45] We instead find that the best reading of the statute does not constrain EPA in the manner the commenter suggests.

[43] EPA, "RFS Program: RFS Annual Rules – Response to Comments," EPA-420-R-22-009, June 2022 ("2020–2022 RFS Rule RTC").
[44] See CAA section 211(o)(1)(B)(i), CAA section 211(o)(2)(B)(i)(II).
[45] See, *e.g.*, CAA section 211(o)(2)(B)(ii)(III) (requiring EPA to analyze "the expected annual rate of future commercial production of renewable fuels" generally).

6.1.5 Alternative Volume Scenarios

Comment:

Many commenters specifically requested an implied conventional volume of 14.2 billion gallons, representing the highest level of ethanol likely to be consumed, stating this new volume requirement would: more accurately reflect the market realities of transportation fuel demand, bring down the cost of RINs, or reduce compliance burdens for independent refiners, biofuel producers, or farmers. One commenter added that independent refiners can serve as vital partners in the economic revitalization of the U.S. and EPA should consider the ripple effects of maintaining the proposed volume requirement. Another commenter stated that greater RIN availability and lower compliance costs would allow refiners to invest further in environmental and energy efficiency enhancements in future years. A few commenters discussed that a 14.2-billion-gallon conventional renewable fuel volume requirement would help decouple D6 from D4 RIN costs. Other commenters suggested that EPA reduce the proposed volumes to levels similar or lower than 2024.

Response:

We recognize that the consumption of conventional ethanol is unlikely to meet the 15-billion-gallon implied conventional renewable fuel volume requirement we are establishing in this rule. In analyzing the impacts of this final rule, we have projected that conventional ethanol consumption will be approximately 14.2–14.3 billion gallons in 2026 and 2027. We project that volumes of non-ethanol fuels, primarily biodiesel and renewable diesel, will be supplied beyond the volumes needed to meet the BBD and advanced biofuel volume requirements to make up for any shortfall in the supply of conventional renewable fuel relative to the implied conventional renewable fuel volume.

Commenters requesting that EPA reduce the implied conventional renewable fuel volume in the final rule generally argued that this reduction would result in lower conventional (D6) RIN prices. These commenters claimed that the benefits of lower D6 RIN prices would be lower cost of compliance to obligated parties and/or lower fuel prices for consumers. In the proposal, we acknowledged that a reduction in the implied conventional renewable fuel volume requirement to below the E10 blendwall would likely result in a reduction in the price of D6 RINs. While this outcome is viewed as a benefit to some stakeholders, namely some obligated parties, we also considered the fact that obligated parties recoup RIN costs through their sales of gasoline and diesel and the impact of low D6 RIN prices on incentives for sales of E15 and E85 when establishing the volumes in this rule. Lower D6 RIN prices would significantly reduce the incentives for parties to invest in the infrastructure necessary to expand the availability of higher-level ethanol blends and would thus negatively impact the potential for greater sales of these fuel blends (and higher consumption of renewable fuel in the transportation fuel pool) in future years. After a consideration of the full scope of the interaction of these market forces, we have decided that it would not be appropriate at this time to reduce the implied conventional renewable fuel volume requirement below the E10 blendwall as requested by the commenters. Further discussion on the impact of RIN prices on the cost of the RFS program (RTC Section 9.1.1), retail fuel prices (RTC Section 9.1.4), and refiners (RTC Section 9.1.8) can be found elsewhere in this document.

Comment:

A commenter suggested that EPA should reduce the implied conventional renewable fuel volume from 15 billion RINs to match the ethanol blendwall from AEO2025 while maintaining the same total renewable mandates. They presented an alternative scenario where the volumes in excess of the blendwall would be allocated to the BBD and advanced fuel categories. They also suggested that advanced biofuel volumes should be set based on North American feedstock availability and that the proposed 50% import RIN reduction should be withdrawn to reduce program compliance costs. The commenter provided detailed tables illustrating their proposed volumes and percentages for both years and claimed this approach would reduce overall RFS compliance costs by 55%, bringing the proposal more in line with the 2023 rule. In recommending this alternative approach, the commenter stated that EPA's proposed approach could not be justified by statutory requirements, as benefits related to energy security and independence, environmental impacts, expected commercial production rates, infrastructure impacts, and opportunities for job creation and rural development would remain constant under their alternative scenario.

Response:

The commenter suggested three ways that EPA could reduce the compliance costs of the 2026 and 2027 volume requirements: (1) reduce the implied conventional renewable fuel volume to the ethanol blendwall; (2) set the advanced biofuel volumes based on feedstocks available from North America; and (3) withdraw the proposed import RIN reduction provisions.

In this action we are not finalizing the proposed import RIN reduction provisions. We continue to believe that these proposed provisions support the statutory goals of the RFS program, and we intend to consider comments we received on the proposed regulations and finalize revised provisions in a future action. Our consideration of reducing the implied conventional renewable fuel volume to the blendwall is discussed in the previous response.

The advanced biofuel volumes in this final rule reflect our consideration of the domestic production capacity of these fuels rather than the availability of feedstocks in North America, as recommended by the commenter. As an initial matter, we note that our assessment of the available feedstocks from North America and the domestic BBD production capacity relatively similar. Of the total volumes of BBD we project will be supplied to meet the volume requirements, we project that approximately 8% and 9% will be produced from imported feedstocks outside of North America in 2026 and 2027, respectively.[46] Our analyses indicate that, in general, the domestic benefits of renewable fuel production and use are greatest when these fuels are produced in the U.S. from domestic feedstocks. However, domestic benefits are also expected to be realized from renewable fuels produced in the U.S. from imported feedstocks. For

[46] These estimates conservatively assume that all the FOG we project will be imported for BBD production in 2026 and 2027 is imported from countries outside North America. Conversely, the estimates assume that all the imported canola oil used for BBD production is imported from Canada and Mexico.

example, all domestically produced renewable fuels are expected to increase energy security and employment, regardless of the source of the feedstock. Because many renewable fuel production facilities are located in rural areas, increased renewable fuel production is also expected to positively impact rural economic development.

The commenter claimed that the alternative approach to the RFS volume requirements in their comments would decrease compliance costs by 55%. Much of this reduction in projected compliance costs is the result of lower D6 RIN prices. While lower D6 RIN prices would reduce the cost to obligated parties to acquire RINs, our analyses has demonstrated that RIN costs are recovered by obligated parties in the prices of the gasoline and diesel they sell (see RIA Chapter 9.1.8), and that RINs operate as a cross-subsidy between renewable fuels and petroleum based fuels and thus do not increase the overall cost of gasoline and diesel fuel at the retail level (see RIA Chapter 9.1.4). Lower D6 RIN prices would also significantly reduce the incentives for investing in infrastructure to increase the sales of higher-level ethanol blends.

The societal costs of the alternative volumes suggested by the commenter are expected to be much closer to the societal costs of the volumes we are finalizing in this rule. The lower advanced biofuel volumes proposed by the commenter would be expected to reduce the societal cost of the RFS volumes for 2026 and 2027, as the cost of production of advanced biofuels such as biodiesel and renewable diesel are generally higher than the cost of production of the petroleum diesel these fuels displace. Nevertheless, after considering our analyses of each of the statutory factors, we have determined that the volume requirements we are finalizing in this rule represent a balancing of these factors in a manner that is consistent with the statutory goals for the RFS program (see Preamble Section III for further discussion of our evaluation of the statutory factors).

Comment:

A commenter suggested that EPA should expand the total renewable fuel volume requirement rather than any specific category, allowing more flexibility to absorb market shocks and to use the lowest cost fuels, which would reduce costs for obligated parties and consumers. Another commenter suggested focusing renewable fuel growth on advanced biofuels.

Response:

In determining the volume requirements for 2026 and 2027, EPA independently considered the impacts of each of the component biofuels (cellulosic biofuel, non-cellulosic advanced biofuel/BBD, and conventional renewable fuel) on each of the statutory factors. As discussed in greater detail in Preamble Section III, each of these component fuel types are projected to have differing impacts on the statutory factors. The volume requirements we are establishing in this rule represent a holistic balancing of the statutory factors, with these broad statutory goals in mind.

When evaluating the renewable fuel volumes in this final rule, we considered both alternatives mentioned by these commenters. In this rule we are focusing on the renewable fuel growth in the advanced biofuel categories, as suggested by one commenter. The cellulosic biofuel, BBD, and advanced biofuel volume requirements are all increasing while the implied conventional renewable fuel volume requirement remains at 15 billion gallons in 2026 and 2027. We believe this is appropriate in light of the current infrastructure limitations on the consumption of higher-level ethanol blends. However, we may consider increasing the conventional renewable fuel volume requirement in future years if our analyses indicate higher volumes would be appropriate.

Alternatively, expanding only the total renewable fuel volume requirement, as suggested by one commenter, would allow for the greatest flexibility to the market and would allow the volume requirements to be met at the lowest cost. Increasing only the total renewable fuel volume requirement would also have consequences. For example, were EPA to set cellulosic biofuel and BBD requirements that are flat of declining this would reduce the guaranteed market for these fuels. This could ultimately discourage investment in the fuel types that have seen the highest rates of growth in recent years and could negatively impact the growth in the domestic capacity to produce and use these fuels in future years. Increasing volume requirements only for the total renewable fuel category would also not account for the differences in potential impacts across a number of statutory the statutory factors, such as differing potential impacts on the environment, infrastructure and job creation and rural economic development. We believe this individual consideration of the component fuel types is consistent with the statutory requirements for establishing volumes in years after 2022 as well as the overall structure Congress established for the RFS program that included four separate but nested volume requirements.

Comment:

A commenter provided a detailed critique of EPA’s analysis of the “No RFS” baseline scenario and the incorporation of the Ethanol Replacement Value. They noted that EPA relied on AEO2023 for estimating total demand for gasoline fuels, despite acknowledging that AEO2023 assumes continuation of the RFS program. The commenter suggested that EPA may be underestimating ethanol demand in the “No RFS” scenario due to regulatory and incentive changes enacted after AEO2023 (*e.g.*, the 45Z credit) and underestimation of the Ethanol Replacement Value term when incorporating the Federal and State Ethanol Tax Subsidies (FETS and SETS parameters). The commenter also criticized EPA’s analysis of E85 economics, particularly the inclusion of a Retail Cost parameter intended to capture the per-gallon cost of revamping a service station to begin offering E85. The commenter argued that EPA is likely underestimating the volume of E85 that would be sold in the “No RFS” scenario.

The commenter raised similar concerns about EPA’s analysis of E15 economics, noting that EPA demonstrates the importance of the Retail Cost parameter in the DRIA, showing that in the case of Washington State, the Retail Cost term makes the difference between E15 being economically viable or non-viable. They argued that EPA errs in using a single, average value for Retail Cost in this analysis, as the cost of adding E15 to a gasoline station varies widely based on site-specific factors. Instead, the commenter suggested that EPA conduct further analysis of Higher Blends Infrastructure Incentive Program data to identify different values of Retail Cost that are representative of the range of costs documented for E15 installations. With such a more detailed analysis, EPA could refine their approach to incorporate the potential to increase E15 share at stations already offering E15, the economics for stations with a representative low cost for addition of E15, and stations with an average cost for addition of E15. More broadly, the commenter provided a comprehensive critique of EPA's method for analyzing market incentives, arguing that it does not fully account for important non-RFS dynamics.

Response:

In our analyses for this final rule, we have addressed many of the issues raised by this commenter. For example, we have updated our analyses using the most recent Annual Energy Outlook (AEO2025) and incorporated an estimate of the average 45Z credit available to ethanol producers. We also updated our estimated retail revamp cost from an engineering estimate based on limited information about the retail station revamps that occur to enable higher-level ethanol blends to one based on actual retail station modification data from HBIIP. The HBIIP data estimates a higher amount of retail station revamp changes and higher costs than our previous engineering estimates. While we primarily used a single estimate of the national average retail infrastructure costs for both E15 and E85, we also analyzed the impact on E15 costs at a lesser extent of retail revamps (no new underground storage tank added) based on a subset of the HBIIP data. We continue to update our cost analysis to reflect higher throughput volumes at E15 stations, and the higher throughput volumes at E85 stations in California. Even the E15 cost analysis at the lower extent of revamps and higher throughput volumes did not show E15 to be economically viable in the No RFS Baseline analysis.

We also note that we do not expect that any underestimate of E15 or E85 in the No RFS baseline would appreciably change the volumes we are finalizing in this rule. We project that relatively small volumes of ethanol (231 million gallons in 2026 and 245 million gallons in 2027) are attributable to this rule. Higher estimates of E15 and E85 consumption in the No RFS Baseline would reduce the volume of ethanol attributable to this rule, but would not impact the volume requirements we are finalizing for 2026 and 2027, which are based in part on our estimate of the total volume of ethanol consumed in these years using a separate projection methodology (see RIA Chapter 7.5 and RTC Section 6.4 for more information on our projection of ethanol consumption in 2026 and 2027).

6.2 Treatment of Carryover RINs

Comment:

Several commenters supported EPA's proposed decision to not intentionally draw down the number of available carryover RINs in setting the 2026–2027 volume requirements. These commenters reiterated the importance of maintaining the availability of carryover RINs in order to provide balance and liquidity in the RIN market, but one commenter stated that the proposed rule fails to do so. Another commenter suggested that many obligated parties will need to rely on carryover RINs in order to meet their obligations in 2026 and 2027 or the market may be severely disrupted by noncompliance.

Conversely, one commenter stated that EPA should intentionally draw down the number of available carryover RINs. The commenter argued that high RIN prices are how the RFS program achieves its goal of increasing use of renewable fuels and that setting volume requirements without regard to the number of available carryover RINs suppresses RIN prices, thereby going against the Congressional intent of the RFS program.

Response:

EPA has carefully considered these comments and as discussed in Preamble Section III.F, 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 believe this approach best balances the various roles of carryover RINs and provides appropriate and significant incentives for renewable fuel use.

EPA appreciates the importance of carryover RINs to the RFS program. Under the statutory provision for credits with a 12-month credit life and the regulations establishing carryover RINs, obligated parties have the option of obtaining and carrying over excess RINs or carrying forward a compliance deficit to the next compliance year. This makes it clear that carryover RINs are a key mechanism for providing compliance flexibility in addition to that provided by the ability to carry forward a deficit. "Buffer" is another way of conceptualizing the compliance flexibility that carryover RINs afford to address uncertainties and unforeseen circumstances and otherwise facilitate compliance efforts, as well as to avoid unnecessary RIN shortages or price spikes and provide liquidity to the RIN trading market. As such, carryover RINs have played a crucial role in actions by obligated parties to plan for and achieve compliance with RFS requirements, in enabling the RIN market to function in a liquid manner, in providing the statutorily required credit program function, in avoiding excessive market price swings, in determining whether and to what extent statutory volume targets can be met, and in reducing the need for subsequent waivers. Because these issues are so fact-specific, different circumstances can and do lead to different decisions by EPA about whether (and how much) to rely on a drawdown in the number of available carryover RINs when balancing the various objectives of the RFS program.

In establishing the renewable fuel volume requirements for 2026–2027, we have weighed these various roles for carryover RINs and sought to appropriately balance them in the context of the statutory factors and the overall statutory goal of increasing the use and production of renewable fuels. In light of our consideration of these factors as well as the factors discussed in Preamble Section III, we have determined that it is appropriate for EPA to set the volume requirements for 2026–2027 without the express intention or expectation of a drawdown in the number of available carryover RINs.

As explained in Preamble Section III.F, we believe it is appropriate for EPA to not intentionally draw down the number of available carryover RINs in setting the 2026–2027 volume requirements. EPA has discretion in determining whether and to what extent we decide to intentionally draw down the number of available carryover RINs in setting the RFS standards. EPA's set authority does not specifically dictate how EPA must consider carryover RINs, and thus Congress delegated this choice to EPA. EPA's discretion over how we consider carryover RINs has been upheld by the D.C. Circuit in multiple prior cases. In *Monroe*, the U.S. Court of Appeals for the D.C. Circuit upheld EPA's decision not to waive the 2013 statutory advanced and total renewable fuel volume requirements based in part on the availability of abundant carryover RINs. In *ACE*, the Court upheld EPA's decision to not consider carryover RINs as part of the "supply" of renewable fuel for purposes of determining whether an "inadequate domestic supply" exists that may warrant a waiver of the standards.[47]

In standard-setting rulemakings, we have assessed the availability of carryover RINs on a rule-by-rule basis taking into account all of the relevant facts before us when determining the appropriate volumes in each annual rule since the 2013 annual rule.[48] In exercising waiver authorities in those standard-setting actions, we have not included the anticipated number of carryover RINs in the final applicable volumes. Consistent with decisions in past rulemakings we have concluded that we should not set the volume requirements for 2026–2027 in a manner that would be expected to require a drawdown in the number of available carryover RINs.

As discussed in the 2014-2016 final rule, having carryover RINs available is analogous to a typical bank account or inventory,[49] in which it is commonly understood that a reserve fund should be maintained to cover unforeseen circumstances.[50] Such unforeseen circumstances range from a drought that adversely affects production of renewable fuel feedstocks, to a cyberattack on biorefineries that directly affects the supply of renewable fuels, to disproportionate reduction in gasoline demand in response to a pandemic. If such currently unforeseen events occur without carryover RINs available to operate as a program buffer, we could see RIN shortages and price spikes, potentially causing a need for an emergency waiver for even relatively small reductions in renewable fuel supply or increases in petroleum fuel demand. This would only create further program uncertainty and impede the investment needed for the program to grow.

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[47] See also *Growth Energy*, 5 F.4th at 18; *Am. Fuel & Petrochemical Manufacturers v. Env't Prot. Agency*, 937 F.3d 559, 583 (D.C. Cir. 2019).
[48] See 78 FR 49820-23 (August 15, 2013), 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).
[49] See 80 FR 77483-84 (December 14, 2015).
[50] For example, on average from year-to-year there is a carryover of roughly 15% of the previous year's corn crop that is carried into the next year.

In addition, while carryover RINs are analogous to a typical bank account in some ways, they are not like a bank account in other important aspects. There is no central bank from which funds can be withdrawn. Rather, it is comprised of individual holdings of various magnitudes by a number of market participants that change over time. As discussed in Preamble Section III.E, some parties hold significant numbers of carryover RINs, while other parties hold none at all. Thus, even when carryover RINs exist, they may not be "available" to parties that need to purchase them for compliance if the parties that own the carryover RINs are unwilling to sell them. The benefit of market liquidity is only achieved if there are an adequate number of RINs available and expected to be available in the future to incent those holding the RINs to sell them to those who need them.

As described in Preamble Section III, EPA is setting the 2026 and 2027 cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel volume requirements under our set authority at levels that provide continued incentives for the production and use of renewable fuels; absent the standards we are establishing in this final rule, the same volumes would likely not be produced or used.[51] Moreover, as explained in RIA Chapter 5, we believe that the final 2026 and 2027 volume requirements can be achieved by the market using actual biofuel use in that year without the need to use carryover RINs to demonstrate compliance. As such, setting volume requirements in this manner should not result in a drawdown in the number of available carryover RINs.

However, as further discussed in Preamble Sections III.F and IV, the SRE reallocation volumes for 2026 and 2027 are intended to be met with carryover RINs attributable to the 2023–2025 exemptions and we 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. Furthermore, the projections on which the standards are based still involve unavoidable uncertainties. As a result, it is possible that our final standards are over-optimistic and that individual obligated parties will face challenges in complying with the standards solely with biofuel used in 2026–2027. Carryover RINs, to the extent they remain available in the marketplace, will be available for such eventualities. It is also possible that the final standards prove to underestimate the market and the obligated parties will be able to over-comply (by using renewable fuel beyond what is required) and increase the number of available carryover RINs.

Contrary to commenters' assertions, the current number of available carryover RINs is not suppressing RIN prices, nor is EPA intending that it do so. Current D6 RIN prices are over $1 per RIN and are indeed incentivizing additional renewable fuel use, consistent with Congress' intent.[52] Furthermore, we do not believe that persistently drawing down the number of available carryover RINs is needed to incentivize increased biofuel use. Indeed, many biofuel producers have made significant investments in production capacity to meet the demand that the RFS standards help create. The concerns that some raised about the potential for the proposed

[51] As described further in RTC Sections 3 and 6, we set the cellulosic biofuel volume at the projected volume available, which is the level to which EPA would reduce the cellulosic biofuel requirement if it exercised the cellulosic waiver authority as discussed in CAA section 211(o)(7)(D)(i). In doing so, we follow the statutory requirements, including CAA section 211(o)(2)(B)(iv), which directs EPA to set the cellulosic volumes at levels that are not expected to require later reduction through a waiver under CAA section 211(o)(7)(D).

[52] For more information on RIN prices and the current number of available carryover RINs, see RIA Chapters 1.7 and 1.8.

standards to damage their businesses appear to be premised, however, on an assumption that renewable fuel production volumes would decline significantly. This is not the case. This final rule will continue to place market-forcing pressure on the production and use of renewable fuels. In 2026 and 2027, we expect significant increases in renewable fuel use, particularly from renewable diesel, much of which are enabled by newly constructed or converted biofuel production facilities built since 2023.[53] Indeed, during the past two years, we have observed significant increases in renewable diesel production capacity, which, prior to a down year in 2025, was utilized at a rate greater than 70%.[54] See also RIA Chapters 3.2 and 3.3, where we show that the volume requirements we are establishing for 2026–2027 represent increases in comparison to actual consumption in 2025 and also in comparison to what would occur in the absence of the RFS program (*i.e.*, the No RFS baseline).

We appreciate that it could be favorable to biofuel producers for us to always count on carryover RINs as a basis to set higher standards, since higher standards generally create higher short-term demand for and/or higher prices for their products. If the standards cannot be achieved, then RIN prices may rise dramatically based on scarcity pricing, creating market turmoil that could operate to the short-term benefit of renewable fuel producers. Such disruption could have significant negative consequences for the renewable fuels market as a whole. Consumers could end up paying considerably more in higher fuel prices as a result for the potential incremental volume of renewable fuel. Certain obligated parties may also not be able to comply. As explained in Preamble Section III.F, such noncompliance could negatively impact the regulatory and market certainty critical to investments in renewable fuels more generally. EPA may also need to intervene by retroactively reducing the standards, which could further undermine regulatory and market certainty.

Comment:

One commenter stated that their analysis showed that there will be no D4 carryover RINs going into the 2026 compliance year and that the total number of carryover RINs will be approximately 3.5% of the 2026 proposed volumes. The commenter recommended that EPA set volumes that enable the number of carryover RINs to be between 9–17% of the volume requirement to enable all obligated parties' ability to comply.

Response:

First, we note that since the Set 2 proposal, we have revised our projection of the number of available carryover RINs due to several events. In August and November 2025, EPA issued decisions on 191 SRE petitions for the 2016–2024 compliance years in the 2025 SRE Decisions Actions, one result of which was a significant number of RINs being returned to obligated parties that had previously retired those RINs to demonstrate compliance. In December 2025, obligated parties retired RINs to demonstrate compliance with their 2024 obligations. Using updated data that reflects these events, we now project that the effective total number of available carryover

[53] For more detail on how the rule may impact the production and use of various renewable fuels, see Preamble Section III and RIA Chapters 3 and 7.
[54] RIA Chapter 7.2.

RINs is 3.6 billion RINs, which is approximately 13–14% of the total renewable fuel standard in 2026 and 2027.

Regardless of these changes to our carryover RIN projection, we would still disagree with the commenter that it would be necessary or appropriate to inflate the number of available carryover RINs to be between 9-17% of the volume requirements in order for the carryover RINs to serve their vital functions. While the commenter made these claims, they failed to adduce concrete data, technical analysis, or other persuasive evidence demonstrating that these particular percentages are necessary for carryover RIN banks to serve their functions, either in general or for 2026–2027.

In rejecting the commenters' arguments, we are not saying that the projected number of available carryover RINs, either in the Set 2 proposal or this final rule, is always the appropriate size or is always sufficient to preserve their vital functions. We are not currently able to identify with specificity an optimal number of carryover RINs. We also do not believe it is necessary to determine an optimal absolute or relative number of carryover RINs, either minimum or maximum. As explained above and in Preamble Section III.F, we consider the number of available carryover RINs on a rule-by-rule basis in each standard-setting rule, and the appropriate number of available carryover RINs depends on a complex agglomerate of regulatory and market factors that cannot be reduced to a single number. We note, however, that the number of available carryover RINs is essentially capped at 20% of the total renewable fuel volume standard due to RFS regulations that do not permit more than 20% of prior-year RINs to be used by an obligated party to comply with the current year's standards.[55]

Comment:

Several commenters believed EPA underestimated the amount of carryover RINs by failing to account for deficits from pending SRE petitions, which could reintroduce additional RINs to the market, increasing the number of available carryover RINs.

Response:

As described above, we have updated our projection of the number of available carryover RINs to account for the 2025 SRE Decisions Actions and obligated parties' compliance with the 2024 standards. While we now project a significantly larger number of available carryover RINs than in the Set 2 proposal, we 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.

[55] See 40 CFR 80.1427(a)(5). We evaluated establishing higher or lower regulatory thresholds in the RFS2 rule, and our rationale for selecting a 20% regulatory threshold is provided in that action. See 75 FR 14734-35 (March 26, 2010). We are not reexamining this issue in this action.

7. Percentage Standards

7.1 General Comments on Percentage Standards

Comment:

Two commenters argued that EPA's adjustment factors effectively nullify the SRE reallocation volume by inappropriately applying adjustment factors to the denominator of the RVO formula, thereby unfairly reducing the final RVO percentage. One of the commenters stated that EPA has no authority to adjust projections from EIA, while another commenter argued that EPA should eliminate the EIA adjustment factor because it is not part of the percentage standards equations in 40 CFR 80.1405.

Response:

First, we note that the D.C. Circuit has previously upheld EPA's decision to use EIA's projected volumes to *inform* EPA's projections of cellulosic biofuel, without requiring "slavish adherence by EPA to the EIA estimate."[56] This is even more true when the statute provides no guiding language to EPA to use EIA's estimates when establishing percentage standards. As noted previously, CAA section 211(o)(3)(A)–(B) no longer applies, as subparagraph (A) and clause (B)(i) indicate that EIA and EPA are to act only through 2021. The D.C. Circuit recently affirmed this interpretation, stating that "the mandate for EPA to achieve the applicable volume goals specifically by means of percentage standards expired at the end of 2021. 42 U.S.C. § 7545(o)(3)(B)(i)" and "although EPA has so far chosen to continue using the formula codified at 40 C.F.R. § 80.1405(c) to impose percentage standards on obligated parties, EPA is no longer required to issue percentage standards at all. *See* 42 U.S.C. § 7545(o)(3)(B)(i)."[57]

However, even if CAA section 211(o)(3)(A)–(B) did apply (which, as stated above, they do not), the language used in those provisions is identical to the language under CAA section 211(o)(7)(D) (the cellulosic waiver authority). CAA section 211(o)(3)(B)(i) provides that EPA is to determine the renewable fuel obligation "based on the estimate provided under paragraph (3)(A)." CAA section 211(o)(7)(D) similarly provides that EPA is to make a determination "based on the estimate provided under paragraph (3)(A)." The D.C. Circuit held that this "based on" language allows EPA to "determine" the obligation and does not require "slavish adherence by EPA to the EIA estimate."[58]

The percentage standards equations in 40 CFR 80.1405 contain variables for the amounts of gasoline, diesel, and renewable fuel *projected* to be used in the covered location (*i.e.*, the contiguous 48 states and Hawaii). The definition of those variables, however, does not specify *how* EPA is to develop its projection or the data source it must use. As described above, the statutory requirement that EIA provide EPA with certain volume estimates applied only through 2021. Furthermore, the statute did not specify *how* EPA was to use those estimates or otherwise

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[56] *API v. EPA*, 706 F.3d 474, 478 (2013) ("*API*"). *See also Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 660 (D.C. Cir. 2019); *ACE*, 864 F.3d at 724, 729.
[57] *Clean Fuels Alliance America v. EPA*, No. 20-1107, 2026 U.S. App. LEXIS 7406, at *7, *14 n.1 (D.C. Cir. March 13, 2026).
[58] *API*, 706 F.3d at 478.

limit EPA from adjusting EIA's estimates (*i.e.*, EIA's estimates *informed* EPA's projections, but did not *limit* EPA from considering other information to adjust those estimates). EPA has the discretion to use data from the source of its choice—and adjust that data based on information from other sources—to make its ultimate projection of the volumes of fuel that will be used in the United States. In this final rule, we have selected AEO2025 as our data source and are adjusting the estimates therein to account for discrepancies between EIA's reported fuel volumes and those reported to EPA by obligated parties.[59]

Furthermore, we disagree that the adjustment factors effectively nullify the SRE reallocation volumes. Just because the commenters do not like the direction of the adjustment (*i.e.*, it reduces the percentage standards) does not mean that the adjustment is unfair. As described in Set 1 Rule RIA Chapter 1.11, it is the so-called "unfair" *overcompliance* that the adjustment factors are designed to address, wherein obligated parties overcomplied with the intended renewable fuel volumes due to EIA's fuel projections being consistently higher than those reported by obligated parties. The adjustment factors do not negate the SRE reallocation volumes; rather, they are designed to better ensure that the actual RVOs reported by obligated parties in 2026 and 2027 align with the intended applicable volumes in this action, including the SRE reallocation volumes.

Comment:

Two commenters argued that EPA's adjustments to the AEO2025 projections were unnecessary and opposed EPA's use of adjustment factors to develop its gasoline and diesel projections from EIA's projections. The commenters argued that STEO and AEO are different reports with different methodologies and different estimates of transportation fuels, making the application of the adjustment factor derived from STEO to AEO arbitrary and capricious. The commenters further argued that EPA's assumption that "data from more recent years is likely to provide a better basis for making projections" was unsupported and that EIA recently updated the AEO2025 methodology to better reflect market availability. The commenters also stated that EPA's use of the new adjustment factors produced estimates consistently higher than the average volumes of gasoline and diesel over the past four compliance years.

Response:

Commenters are incorrect in their assertion that EPA used data from STEO to derive the proposed adjustment factors. Rather, EPA used historical data from the STEO Data Browser, which is a database of forward-looking projections (from the most-recent STEO release) and historical data on actual fuel use (from EIA's Monthly Energy Review). Nevertheless, we recognize the confusion that may have been caused by citing the STEO Data Browser and have updated our technical memorandum detailing the calculation of the final adjustment factors to reference EIA data sources other than the STEO Data Browser.[60]

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[59] While we have adjusted our methodology for adjusting EIA's estimates to now include separate adjustment factors for gasoline and diesel, our underlying rationale remains the same as described in Set 1 Rule RIA Chapter 1.11.
[60] See "AEO2025 Adjustment Factors for Set 2 Final Rule," available in the docket for this action.

With regard to EPA's use of weighting factors, while we believe our proposed approach to place greater emphasis on data from more recent years was a reasonable approach, we have nonetheless decided in this final rule to instead use an unweighted three-year average (2022–2024) to determine the average difference between EIA's reported fuel volumes and those volumes reported by obligated parties to EPA. This approach is analogous to the approach we are using to project the exempted volumes of gasoline and diesel for 2026 and 2027—which are based on a three-year average of the most recent data available—and addresses the concerns raised by the commenters about placing the greatest weight on the most recent year's data. We note, however, that we may change our approach in future rulemakings if we determine that the most recent year's data is a better predictor of the difference between EIA's reported fuel volumes and those volumes reported by obligated parties to EPA.

Finally, it is unclear to EPA what the relevance is of the gasoline and diesel projections for 2026 and 2027 being greater than the average gasoline and diesel volumes over the past four compliance years. Commenters do not explain why projections for two future years being greater than a four-year historical average is invalid, arbitrary, or capricious, especially since those compliance years were for years immediately after the Covid-19 pandemic struck in 2020 and transportation fuel use significantly decreased. We further note that gasoline and diesel use still has not recovered to pre-pandemic levels.[61]

Comment:

Two commenters argued that EPA inappropriately applied the diesel adjustment factor to AEO2025 projections of BBD without providing an analysis of discrepancies between projected and actual BBD volumes.

Response:

As described in the technical memorandum detailing the calculation of the adjustment factors, the gasoline and diesel adjustment factors are calculated based on a comparison of the volumes of gasoline and diesel reported by obligated parties to the volumes of petroleum-based gasoline and diesel reported by EIA.[62] The volumes of petroleum-based gasoline and diesel are calculated by subtracting the projected volumes of renewable fuels in gasoline and diesel from the projected total volumes of gasoline and diesel, respectively, as these projected total volumes contain renewable fuels (*e.g.*, ethanol in gasoline; biodiesel and renewable diesel in diesel). Using gasoline as an example and translated to terms similar to those used in the percentage standard equations in 40 CFR 80.1405:

[61] See actual gasoline and diesel reported by obligated parties in 2019 (188 billion gallons) compared to 2024 (179 billion gallons). "RFS Compliance Data as of February 20, 2026," available in the docket for this action.
[62] See "AEO2025 Adjustment Factors for Set 2 Final Rule," available in the docket for this action.

$$G_{OP} = G_{AF} * G_{PB}$$

$$G_{PB} = G_{EIA} - RG_{EIA}$$

$$\therefore G_{OP} = G_{AF} * (G_{EIA} - RG_{EIA}) = G_{AF} * G_{EIA} - G_{AF} * RG_{EIA}$$

Where:

G_{OP}	=	Volume of gasoline reported by obligated parties.
G_{AF}	=	Adjustment factor for gasoline.
G_{PB}	=	Volume of petroleum-based gasoline projected by EIA.
G_{EIA}	=	Volume of gasoline (including renewable fuels) projected by EIA.
RG_{EIA}	=	Volume of renewable fuels contained in gasoline projected by EIA (*i.e.*, G_{EIA}).

Similar equations can also be written for diesel. Thus, it is mathematically correct to apply the gasoline and diesel adjustment factors to the AEO2025 projected volumes of renewable fuels in gasoline and diesel, respectively, and no separate analysis is necessary or appropriate for comparing projected versus actual volumes of renewable fuels such as BBD.

Comment:

Two commenters opposed EPA's application of the diesel adjustment factor to the AEO2025 distillate fuel projection as the basis for projecting obligated diesel volumes in 2026 and 2027. One of the commenters argued that the AEO2025 distillate fuel projection includes non-obligated fuels such as heating oil and that because AEO2025 includes a diesel fuel projection, it is a better measure of obligated diesel fuel volumes in 2026 and 2027.

Response:

We disagree that the diesel projection in AEO2025 would be a better projection of obligated diesel volumes in 2026 and 2027. As described in the technical memorandum detailing the calculation of the adjustment factors, EIA collects data on distillate fuel use in the United States but does not distinguish between diesel fuel and other distillate fuel oils.[63] Thus, we are unable to directly compare volumes of diesel reported by obligated parties to non-existent historical volumes of diesel from EIA in order to determine how well EIA's diesel projections agree with EMTS data. Instead, we used historical distillate data from EIA in order to develop an adjustment factor that not only accounts for the differences in EIA's volumes of distillate and EPA's volumes of diesel, but that also negates the need to separately adjust EIA's projections for other non-obligated fuel use (*e.g.*, fuel used in Alaska or in ocean-going vessels). The gasoline and diesel adjustment factors developed by EPA for this final rule incorporate all the adjustments we believe are necessary to project the volumes of obligated gasoline and diesel in 2026–2027 and therefore we are no longer separately adjusting EIA's fuel projections to account for these non-obligated fuel uses, as we have in previous RFS standard-setting rulemakings.[64] We erroneously included an adjustment for fuel used in Alaksa in the technical memorandum

[63] See "AEO2025 Adjustment Factors for Set 2 Final Rule," available in the docket for this action.
[64] See, *e.g.*, "Calculation of Percent Standards for 2022 – Final," Docket Item No. EPA-HQ-OAR-2021-0324-0771.

detailing the proposed AEO2025 projections for the Set 2 supplemental proposal;[65] we have removed this adjustment in the calculation of the final percentage standards for 2026 and 2027.[66]

[65] "AEO2025 Projections and Adjustment Factors for Set 2 Supplemental Proposal," Docket Item No. EPA-HQ-OAR-2024-0505-0656.
[66] "Calculation of Final 2026 and 2027 RFS Percentage Standards," available in the docket for this action.

7.2 Accounting for Small Refinery Exemptions

Comment:

Many stakeholders submitted comments on the Set 2 proposal regarding EPA’s projection of 2026 and 2027 SRE volumes and the potential for EPA to reallocate SRE volumes from previous compliance years.

Response:

EPA considers these comments moot as a result of the Set 2 supplemental proposal that proposed to address the SRE issues raised by commenters. We address the specific issues raised by commenters on the Set 2 supplemental proposal in Section 7.3.

7.3 SRE Reallocation Volumes

7.3.1 Legal Authority

Comment:

Several commenters suggested that EPA is required to "ensure" that "the requirements of paragraph 2 are met" under CAA section 211(o)(3)(B)(i). Under this reading, the commenters suggested that EPA must reallocate 100% of the shortfall caused by SREs. A commenter drew a distinction between making up for a shortfall in fuel production or a natural disaster, which the commenter argues do not need to be made up, and exempt volume due to SREs and suggested the latter would be "intentionally guaranteeing that the volumes are not met," and that doing so would violate "the 'ensure' duty." A commenter pointed to the D.C. Circuit's characterization of the "ensure" mandate as "EPA's core mandate."[67]

A commenter suggested that consistent with statements by the D.C. Circuit in *Wynnewood v. EPA*, EPA's core mandate is to ensure the annual renewable fuel volumes are met, and that this mandate continues after 2022. The commenter pointed to CAA section 211(o)(2)(A)(iii)(I), which requires that EPA "ensure" the volumes "regardless of the date of promulgation." The commenter pointed to EPA's use of the "ensure" language to support EPA's action to make projections of exempt gasoline and diesel volume from SREs when setting the percentage standards each year going forward, originally promulgated in the 2020 annual rule as evidence that EPA believes the 'ensure' duty continues beyond 2022. The commenter suggested that the "ensure" duty within CAA section 211(o)(3)(B)(i) is not time limited, stating that the "2005 through 2021" only applies to the November 30 deadline, and that CAA section 211(o)(3)(B)(i) is thus still operative.

Several commenters also supported the proposal to reallocate 100% of SRE volumes for 2023-2025, noting that EPA is obligated to "ensure" the RFS volumes are met, regardless of agency delay, citing the CAA and recent D.C. Circuit case law. Several commenters suggested EPA had a mandate or an obligation to ensure compliance with the volumes, with some citing CAA section 211(o)(2)(A)(i), 211(o)(3)(B)(i), separately or in combination. A commenter suggested that the D.C. Circuit's decision in *Sinclair* requires EPA to "fully remed[y]" any shortfall through reallocation. The commenter also indicated that anything less than 100% reallocation would be "inconsistent with the statute" and "insufficient to mitigate the potential impacts of the action." Multiple commenters stated the statutory "ensure" language requires EPA to reallocate 100% of the exemptions.

A commenter pointed to CAA section 211(o)(3)(C) as evidence that EPA must reallocate all exempt volume.

[67] *Wynnewood v. EPA*, 77 F.4th 767 (D.C. Cir. 2023).

Response:

We are not establishing the SRE reallocation volumes using the "ensure" authority in CAA section 211(o)(2)(A) or 211(o)(3)(B). We recognize that we have used this language in the past to establish the amended percentage standard equations that project SREs for future years. We have also used language in CAA section 211(o)(2)(A) to put in place requirements on renewable fuel producers among other compliance mechanisms. However, we find that such authority is not needed to establish the SRE reallocation volumes as our authority under CAA section 211(o)(2)(B)(ii) is broad enough to encompass consideration of carryover RINs and SREs and, thus, to establish SRE reallocation volumes. It is also the most appropriate mechanism to address circumstances where excess carryover RINs may impair the renewable fuel volume requirements from being realized through new production and use. CAA section 211(o)(2)(B)(ii) states that EPA is to determine volumes based on a consideration of review of implementation of the program in the years 2006–2022, as well as other enumerated factors. One such factor is the "expected annual rate of future commercial production of renewable fuels." As explained elsewhere, we believe that without reallocating 70% of the 2023–2025 exempted RVOs, the annual rate of future renewable fuel production in 2026 and 2027 would be reduced because obligated parties would be inclined to use carryover RINs to demonstrate compliance instead of acquiring renewable fuel produced and used in 2026 and 2027. Therefore, we are establishing applicable volumes that both encourage new renewable fuel production in 2026 and 2027 and address the excess carryover RINs in the market.

We disagree that CAA section 211(o)(3)(C) indicates that EPA must reallocate all the 2023–2025 exempted RVOs. As described in response to other comments in this section, CAA section 211(o)(3) does not apply after 2021. As we stated in 2022, this provision indicates that Congress expressly considered the impacts of SREs on the annual standard-setting process, chose to mandate this sole adjustment, and entrusted discretion to make other potential adjustments to EPA.[68]

Comment:

A commenter supported EPA's finding that 2023–2025 exempt volumes and the resulting carryover RINs have the potential to diminish the binding force of the 2026 and 2027 standards because obligated parties could use carryover RINs instead of acquiring renewable fuel produced in 2026 and 2027. The commenter noted that EPA's proposal is consistent with EPA's action to modify the percentage standard formula to account for SREs, and that such action was upheld by the D.C. Circuit in *Sinclair*. The commenter noted that EPA is "required to engage in reasoned decisionmaking" and that EPA must consider all important aspects of the problem and "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choices made." The commenter suggested that setting standards without accounting for the SREs will result in EPA knowingly setting standards that will not be met in the market. The commenter stated that allowing any amount of the exempt volume carryover RINs to persist would create a perpetual problem in EPA's standard setting

[68] 2020–2022 RFS Rule RTC at 139.

rulemakings in the future, because the carryover volume would persist and make the standards fall short.

Response:

We appreciate the commenter's support. In this final rule we are establishing SRE reallocation volumes for 2026 and 2027 that are intended to prevent the available carryover RINs from reducing demand for renewable fuels below the volume requirements in 2026 and 2027. We considered reallocating 100% of the 2023–2025 exempted RVOs and find that doing so would not be appropriate. Prior to the 2025 SRE Decisions Actions, available carryover RINs in recent years have been diminished, with the effective number of carryover RINs estimated to be 0 as recently as the Set 2 proposal.[69] We note as well that some amount of the excess RINs attributable to the 2023–2025 exempted RVOs may not actually be available for the market to use, and instead may be used to fulfill deficits of obligated parties from 2025 and earlier. As noted in Preamble Section IV, we also find that carryover RINs generally serve programmatic benefits, and thus a complete drawdown of the number of carryover RINs is not desirable. Thus, we decline to require 100% reallocation. We also find that 50% reallocation would likely result in the use of a quantity of carryover RINs that exceeds the SRE reallocation volumes over 2026 and 2027, and thus has the potential to reduce demand for renewable fuel in those years.

Comment:

A commenter suggested that reallocation is required to ensure the minimum volume requirements for 2026 and 2027. The commenter noted the Congressional goal to promote increased production of biofuels and argued that the 12-month lifespan of RINs indicates a desire to support actual production in the compliance year. The commenter also noted EPA's 20% limit on carryover RINs being used to satisfy the volume requirements as being further evidence to support actual production in the compliance year. The commenter noted that the retroactively granted exemptions could impermissibly expand the lifespan of RINs unless they are accounted for.

Response:

EPA is establishing the SRE reallocation volumes to protect the market-forcing nature of the 2026 and 2027 volume requirements under CAA section 211(o)(2)(B)(ii). We disagree that the rollover of RINs by obligated parties is "impermissibly expanding the lifespan of RINs." As described in Preamble Section III.F, it is permissible for obligated parties to retire prior-year RINs for compliance that would otherwise expire, such that current-year RINs can be banked for the next compliance year and become "carryover RINs."

Comment:

A commenter also suggested that 100% reallocation was particularly necessary in light of EPA's waiver authorities in CAA section 211(o)(7); the commenter suggested that the SREs were akin to waiving the volumes without the criteria in CAA section 211(o)(7) being met. Other

[69] 90 FR 25827-28 (June 17, 2025).

commenters suggested that retroactively granted exemptions are effectively a waiver as they reduce the volume requirements; they noted EPA has acknowledged SREs reduce the volume requirements. Commenters suggested EPA's waiver authority is limited under the CAA. Another commenter suggested that a failure to account for 2023–2025 exemptions would amount to an improper waiver of the volume requirements, noting the historical shortfalls in the renewable fuel volumes when SREs are granted. The commenter explained that because less gasoline and diesel fuel is subject to the annual percentage standards that are supposed to "ensure" the minimum volume requirements are met there is an effective reduction in the renewable fuel obligations.

Another commenter suggested that the limit on the lifespan of RINs in CAA section 211(o)(5) and the limitations on EPA's waiver authorities in CAA section 211(o)(7) indicate "clear limits" from Congress on EPA's ability to reduce the volume requirements, and that the retroactive issuance of SREs without reallocation undermines these Congressional directives.

A commenter suggested that given the market-forcing nature of the RFS program, and congressional direction on the lifespan of credits in CAA section 211(o)(5)(C) to "incentivize new production," EPA must take action to account for the additional RINs from SREs. The commenter also suggested these additional RINs undermine the purposes of the volume requirements, and thus EPA is obligated to ensure the SREs do not undermine the incentives for actual production of renewable fuels. The commenter suggested this requires 100% reallocation.

A commenter noted that 100% reallocation would "simply preserve the [Set 2 proposal] analysis and thus preserve the[] positive overall consequences consistent with Congress' objectives and the statutory factors." The commenter suggested less than 100% reallocation would diminish or eliminate the statutory benefits.

Response:

As described previously, EPA agrees that there are specific waiver authorities provided in the statute that allow for the downward adjustment of the applicable volumes, including the general waiver authority in CAA section 211(o)(7)(A), the cellulosic waiver authority in CAA section 211(o)(7)(D), and the BBD waiver authority in CAA section 211(o)(7)(E). EPA also agrees that CAA section 211(o)(5) requires EPA to implement a credit provision for the RFS program and that such credits have a designated lifespan. However, none of these provisions specifically address whether EPA is authorized to account for SREs in establishing applicable volumes under CAA section 211(o)(2)(B)(ii) nor do they address specifically how EPA must account for SREs. The approach we are finalizing in this rule properly balances the need to preserve the market-forcing nature of the standards, while also providing some flexibility to obligated parties, including by allowing some of the excess RINs attributable to the 2023–2025 exempted RVOs to remain available, instead of requiring retirement of all those RINs through 100% reallocation. Thus, for the reasons discussed in Preamble Section IV, we are finalizing SRE reallocation volumes equal to 70% of the 2023–2025 exempted RVOs.

Comment:

A commenter suggested that partial reallocation does not satisfy EPA's duty to "ensure that the required volumes are achieved." Commenters also noted that EPA's authority to reallocate exempt volume was upheld by the D.C. Circuit in *Sinclair v. EPA*, 101 F.4th 871, 891 (2024). Another commenter noted partial reallocation—such as 50%—lacked a rational basis in the record and would leave renewable fuel obligations unmet with new renewable fuel. The commenter argued that full reallocation would support renewable fuel growth, reduce emissions, and support rural economies. A commenter suggested 100% reallocation best serves Congressional intent to force the market to increase renewable fuel use and increase energy security and independence, reduce GHG emissions, and promote job growth and rural economic development. The commenter stated it is also most consistent with the proposed applicable volumes. The commenter said reallocation would not harm obligated parties because they can avoid all net RIN costs and any remaining costs would be too small to justify non-reallocation. The commenter noted no statutory factor is affected adversely by reallocation, and that less than 100% reallocation could not be justified by preservation or increases in the number of available carryover RINs.

Response:

As described elsewhere, we do not rely on the statutory "ensure" language to establish the SRE reallocation volumes. Instead, we rely on CAA section 211(o)(2)(B)(ii), which provides flexibility for EPA to preserve the market-forcing nature of the 2026 and 2027 renewable fuel volume requirements, and maintain some flexibilities for obligated parties. This approach will require a significant drawdown in the number of available carryover RINs. Allowing some carryover RINs to remain in the market also serves programmatic functions, including those discussed in Preamble Section III.F.

Comment:

Commenters argued that, at a minimum, EPA has discretion to fully reallocate the 2023–2025 exempted RVOs. The commenters suggested two sources of authority for EPA: the "ensure" mandate, as well as the "set" provision. The commenters noted that SREs, if not reallocated, ultimately suppress renewable fuel usage in the year they are granted, or by inflating the number of carryover RINs in future years. The commenters supported EPA's analysis in the supplemental proposal.

A commenter noted that the direction to consider "implementation of the program" includes SREs. The same commenter suggested that retroactively granted SREs have resulted in uncertainty in the volume requirements, volatility in the market, and reductions in the volume requirements. The commenter supported EPA's intent in establishing the SRE reallocation volumes in order to main the volumes proposed in 2026 and 2027. Another commenter noted that the supplemental proposal also properly considered the statutory factors, given that full reallocation would "preserve the intended binding force of the proposed volume requirements." The commenters also suggested that reallocation of less than 100% of the exempt volume would be arbitrary and capricious. The commenters pointed to the goals of the RFS program, noting the “market-forcing” nature of the program. The commenters noted the increased use of biofuels under the Set 2 proposal, and the benefits associated with the proposed volumes.

Response:

We agree with the commenters who supported our use of CAA section 211(o)(2)(B)(ii) to establish SRE reallocation volumes. As discussed elsewhere, we are not relying on CAA section 211(o)(2)(A) or 211(o)(3) and the “ensure” language to establish the SRE reallocation volumes.

Comment:

A commenter suggested that the SRE reallocation volumes do not present issues of “fairness” because EPA has previously indicated that it must reallocate exempted volumes.

Response:

While we agree that parties may have some notice based on prior EPA actions, we have not stated in absolute terms that we must reallocate exempted volumes. However, parties were provided actual notice by the supplemental proposal that in the current circumstances we find it appropriate to reallocate some of the 2023–2025 exempted RVOs.

Comment:

A commenter suggested that EPA’s SRE reallocation volumes present the issue of the “Major Question Doctrine” due to vast economic and political significance resulting from the Agency’s action. The commenter highlighted “multi-billion [dollar] effects that eventually get passed through to consumers with EMA marketers stuck in the middle.” The commenter suggested that there is a difference between adjusting volumes of renewable fuels and “shifting specific legally assigned obligations of private parties.” Another commenter suggested that reallocating volumes from previous years is a major question for which Congress must provide a clear statement. The commenter noted that the 11.4 billion gallons of exempted gasoline and diesel “Make this of significant economic impact to . . . both exempt and non-exempt parties, [and] renewable fuel producers.” The commenter noted a lack of congressional authority to implement the reallocation. The commenter noted Congress could have included reallocation language in CAA section 211(o)(9) (the SRE provision), and that CAA section 211(o)(9)(D) contemplates waiver of the exemption by small refineries and provides additional guidance for the small refinery. The commenter also notes other waiver provisions within the CAA, but none specific to exempt volume being made up by other regulated entities. The commenter pointed to the emergency fuel waiver provision and that EPA has never attempted to make up for the waiver through additional reductions in RVP or other fuel qualities in other locations to “make up” for the fuel being distributed under the waiver.

Response:

We disagree that the SRE reallocation volumes implicate the “major question doctrine.” As an initial matter, the consumer price impacts the commenter notes are not specific to the SRE reallocation volume, and the commenter does not present an argument as to why the SRE reallocation volumes in particular result in these effects. We disagree that this action shifts legal obligations from one party to another as the commenter describes; we are instead assessing the unrequired volume of renewable fuel from 2023–2025 (through an assessment of the SREs granted (or projected to be granted) in 2023–2025), and taking 70% of that volume and adding it to the 2026 and 2027 volume requirements. That volume is then incorporated into the nationwide applicable volumes, which is then applied to each individual obligated party through the percentage standards, which proportionally apply to the obligated parties based on their production and import of gasoline and diesel.

It is true that without the granting of SREs, small refineries would have been required to retire the RINs associated with the SRE reallocation volumes; in this action we are distributing 70% of the 2023–2025 exempted RVOs across the pool of non-exempt obligated parties for 2026 and 2027 for the reasons discussed in Preamble Section IV.

In this action, we are reallocating 2.03 billion RINs: 0.99 billion in 2026 and 1.04 billion in 2027. The 2026 total renewable fuel volume requirement is 25.82 billion RINs, and the 2027 total renewable fuel volume requirement is 25.98 billion RINs. Thus, the SRE reallocation volumes represent only a small fraction of the total required volume in 2026 and 2027 (approximately 4% in each year). We recognize that Congress did not require EPA to reallocate exempt volumes. However, Congress did give EPA "considerable discretion to weigh and balance the various factors" in determining volumes under CAA section 211(o)(2)(B)(ii).[70] In establishing the SRE reallocation volumes, we have emphasized the projected rate of commercial production of renewable fuels, and the cascading impacts on the other factors were EPA not to establish an SRE reallocation volume to require the retirement of excess RINs attributable to the 2023–2025 exempted RVOs.

The commenter's suggestion that the emergency fuel waiver provision under CAA section 211(c) sheds light on how EPA should address SREs is inapposite. For one, the emergency fuel waivers do not directly relate to the RFS program, which has its own waiver provisions in CAA section 211(o)(7). Additionally, EPA has never taken the position that the SREs are "waivers" under CAA section 211(o), and thus comparison to another CAA waiver is not proper.

Comment:

A commenter pointed to the separate credit provision in CAA section 211(o)(5) as a means only of facilitating compliance by obligated parties, and not a means to increase obligations. The commenter also suggested that the SRE reallocation volumes extend RFS obligations beyond 12 months time and transfer the obligations from one party to another (including those who may have been exempt in previous years). The commenter quoted EPA's statements about CAA section 211(o)(3)(C)(ii): "[w]hatever renewable fuels small refineries and small refineries blend will be reflected as RINs available in the market; thus there is no need for a separate accounting of their renewable fuel use in the equations used to determine the standards. We proposed and are finalizing this value as zero." The commenter also noted that any statutory provisions about the

[70] *CBD*, 141 F.4th at 171, citing *Sinclair Wyo. Refin. Co. LLC v. EPA*, 101 F.4th 871, 887 (D.C. Cir. 2024) ("*Sinclair*").

relationship between the previous year's volumes and the future year's volumes are flexibilities for obligated parties (such as CAA section 211(o)(3)(C)(ii), or the carry forward deficit provision (CAA section 211(o)(5)(D)), or waiver authorities (such as the "reset authority" in CAA section 211(o)(7)(F)). Another commenter highlighted other provisions that provide flexibilities to mitigate burdens on obligated parties such as CAA section 211(o)(9), (o)(1)(K), (o)(3)(C)(i-ii), (o)(2)–(3), (o)(7)(F) and (o)(5)(D).

Response:

We do not utilize CAA section 211(o)(5) as a basis for our SRE reallocation volume and note that EPA is still acting consistent with its directive to allow for the generation of credits and that such credits will have a 12-month lifespan. We recognize that depending on the circumstances, it is possible that the SRE reallocation volumes may result in an obligated party that received an exemption in a prior year being required to retire RINs to comply with the 2026 and 2027 requirements, which includes SRE reallocation volumes associated with 2023–2025. Nevertheless, we find that this is acceptable. As noted in prior actions, we find that it is appropriate to place the obligation on all obligated parties in 2026 and 2027, even those who may have received exemptions in 2023–2025, because carryover RINs function such that each year's obligations are linked to prior year obligations.[71] We note as well that we continue to believe that it is appropriate to subject all obligated parties to the same percentage standards. The overall programmatic goals of implementing the SRE reallocation volumes are benefitted by this standard applying to all obligated parties in 2026 and 2027. We have provided all parties who will be subject to the 2026 and 2027 SRE reallocation volumes with notice that this standard will apply to them through this notice and comment rulemaking process. Additionally, consideration of SREs in 2026 and 2027 will properly consider the full applicable volume for 2026 and 2027 and thus will inherently consider the SRE reallocation volumes in assessing those individual petitions.

We recognize that the statute contains several flexibilities for obligated parties. The SRE reallocation volumes do not impair these flexibilities. The provisions cited by the commenters demonstrate Congressional recognition of the potential impacts of the RFS program on obligated parties. But they do not indicate a limitation on EPA's ability to set market-forcing standards that require the use of some amount of carryover RINs when the circumstances justify such an action.

Comment:

A commenter suggested that EPA could simply increase the volume requirements after consideration of the statutory factors instead of establishing "SRE reallocation volumes," and that doing so would provide proper notice, particularly if it was proposed in the first instance when EPA issued the proposal in June 2025. The commenter suggested that EPA's SNPRM, and statements that the agency would only accept comments on the SNPRM violated the Administrative Procedures Act (APA) as it prevented stakeholders from fully understanding or commenting on the full volume requirements.

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[71] See the 2020–2022 RFS Rule (87 FR 39600; July 1, 2022) and Set 1 Rule (88 FR 44468; July 12, 2023), where we applied the supplemental standard to all obligated parties in 2022 and 2023.

A commenter suggested the SNPRM violates the APA because it significantly alters the volume obligations without sufficient explanation, thus depriving the public from providing informed comments. The commenter also took issue with EPA's issuance of the SNPRM after the comment period ended and limited comment to issues within the SNPRM. The commenter argued that the SNPRM is not severable from the Set 2 proposal, and thus comment should have been permitted on the entire proposal, in violation of APA sections 553(b) and (c).

Response:

We find it appropriate to establish SRE reallocation volumes that are explicitly tied to the 2023–2025 exempted RVOs and that are distinct from the renewable fuel volume requirements, which represent renewable fuel that we anticipate being produced and used in 2026 and 2027. At the time of the Set 2 proposal in June 2025, EPA was unable to account for SREs as the Agency did not yet have a policy for adjudicating SRE petitions going forward.

The public was put on notice of the addition of the SRE reallocation volumes to the previously proposed volume requirements for 2026 and 2027 when EPA proposed the Set 2 supplemental proposal before finalizing the original proposal. We disagree that the direction in the Set 2 supplemental proposal that EPA would consider comments on topics other than the SRE reallocation volumes beyond the scope of the supplemental proposal violates the APA. EPA provided stakeholders with the necessary analysis, including the proposed applicable volumes including both the SRE reallocation volumes and the renewable fuel requirements. This notice is sufficient for stakeholders to meaningfully comment.

We also disagree that the Set 2 supplemental proposal failed to provide sufficient explanation. The commenter did not provide examples of information that was missing from the Set 2 supplemental proposal. While the Set 2 supplemental proposal did seek comment on the range of SRE reallocation volumes, the commenter did not explain why this did not allow for meaningful comment. Indeed, this framing allows stakeholders to comment on all aspects of potential SRE reallocation.

EPA disagrees the 52-day comment period for the Set 2 proposal was insufficient,[72] as it was longer than Congress's presumptively appropriate minimum comment period for CAA actions of 30 days.[73] As a clarifying point, pursuant to CAA section 307(d)(1)(E), this action is subject to the rulemaking requirements of CAA section 307(d) and not the APA. Per CAA section 307(d)(3) and (5), the Set 2 proposal and supplemental proposal were published in the *Federal Register* and EPA took comments on and held public hearings for both. The Set 2 supplemental proposal reasonably limited the solicitation of comments to its specific contents, as the public had already been given an opportunity to share their views on matters that EPA was not proposing to modify in the supplemental proposal.

[72] The comment period on the Set 2 proposal opened on June 17, 2025, and closed on August 8, 2025. 90 FR 25784 (June 17, 2025).
[73] CAA section 307(h).

Comment:

A commenter suggested that EPA's violation of the 14-month lead-time in CAA section 211(o)(2)(B)(ii) is distinct from prior caselaw on EPA's late and retroactive rulemakings. The commenter presented a scenario in which an obligated party plans to comply with the Set 2 volumes, but cannot comply with the standards that include newly granted SREs, resulting in the obligated party needing to carry forward a deficit. The commenter highlighted in particular that small refineries can petition for SREs "at any time" and that the SRE exemptions are "not time-bound" which disrupts predictability for obligated parties. The commenter suggested SRE reallocation volumes are "especially punitive because it imposes new burdens on previous conduct," and that this is particularly so given the lead-time requirements in the statute.

Response:

We have addressed the late and partially retroactive nature of this action in Preamble Section II. We do not find the commenter's suggestions to be persuasive. As described elsewhere in this section, we do not intend to adjust the SRE reallocation volumes after this final rule, and thus obligated parties will be aware of the standards with which they must comply.

Comment:

A commenter noted that the SRE reallocation volume is the first time EPA has proposed to alter the numerator by adding an additional volume of renewable fuel.

Response:

The commenter is correct that this is the first instance of EPA adjusting the applicable volumes to account for SREs. This is also the first time EPA has retroactively granted SREs of this magnitude immediately after the Agency issued a proposal to establish applicable volumes under the Set authority. Therefore, we find that the circumstances justify EPA's action in this rule in this issue of first impression.

Comment:

A commenter also pointed to the D.C. Circuit's decision in *CBD* upholding EPA's original interpretation of the Set authority and indicated that EPA should only consider "supply side factors" in its review of implementation of the program and not "the impact of carryover RINs on future renewable fuel demand." The commenter quoted the Court's statement that "[b]y using available data bearing on the statutory supply-side factors to develop preliminary candidate volumes, then balancing all the statutory factors before setting final volumes, EPA fulfilled its statutory obligation for each category of renewable fuel."

Another commenter suggested that reallocation volumes would "bypass the statutory six-factor test Congress required EPA to use to set volumes in the first place by increasing the RVO without going through the full, proper analysis." The commenter suggested that Congress gave explicit authority to reduce the total volume requirements for renewable fuel used by exempt small refineries, and that the lack of authority to increase the volume requirements to reallocate SREs indicates "intentional exclusion by Congress."

Response:

We recognize that the D.C. Circuit upheld the 2023–2025 applicable volumes and the majority of the analysis supporting those volumes. However, we do not find that the Court's decision limits our ability to consider carryover RINs as the commenter suggests. Rather, in the same decision, the Court stated, "we give EPA considerable discretion to weigh and balance the various factors required by statute."[74] Such factors include the "expected future rate of commercial production" and "other factors." In this final rule, we have considered the statutory factors in CAA section 211(o)(2)(B)(ii) and that analysis is provided in the RIA and Preamble Section III.

We respond to comments about CAA section 211(o)(3)(c) and the reduction in the RVO for renewable fuel used by exempt small refineries elsewhere in this document.

Comment:

A commenter suggested that statutory history supports reducing the annual RVO to reflect renewable fuel used by exempt small refineries, and not increasing it, because the RIN system did not exist at the time of enactment of EPAct, The commenter suggested that "[c]redits were later created in the 2007 amendments to track renewable fuel use," and that initially compliance was achieved "by direct blending, not through tradable credits." The commenter explained that Congress created statutory provisions to permit downward adjustments to prevent compliance obstacles given that exempt small refineries may have blended renewable fuel, depleting the volume available to obligated parties. The commenter suggested the statutory provision acknowledged that, prior to the RIN system, it was not known that exempt small refineries would be able to sell credits associated with renewable fuel use.

Response:

We recognize the history of CAA section 211(o)(3)(C), but do not find that it informs our action in this final rule.

Comment:

A commenter noted that reallocation would undermine Executive Order 14154 ("Unleashing American Energy") through harm to refineries, including refinery closures and job losses.

[74] *CBD*, 141 F.4th at 171 (citing *Sinclair*, 101 F.4th at 887).

Response:

We do not anticipate that the SRE reallocation volumes are likely to harm refineries resulting in refinery closures and job losses. We respond to comments about impacts on refiners in RTC Section 9.1.8.

Comment:

A commenter suggested that the SRE reallocation volumes exacerbate timing and implementation issues associated with delays in annual standards and SRE decisions. The commenter also noted that small refineries that received only partial exemptions will be penalized by having to "absorb[] additional compliance burdens" and "by losing the practical value of pre-2023 RINs that no longer carry meaningful worth."

Response:

We recognize that small refineries that receive a partial exemption in 2026 or 2027 will be required to comply with half of their RVOs for that year. As the SRE reallocation volumes are part of the applicable volumes, we find that such an outcome is acceptable.

Comment:

A commenter suggested that the SRE reallocation volumes are impermissibly retroactive. The commenter drew distinctions between the SRE reallocation volume and prior RFS retroactivity case law. In particular, the commenter pointed to *NPRA v. EPA*,[75] and its conclusion that "[t]o the extent the Final Rule may be retroactive, we hold that EPA did not exceed its statutory authority under the EISA." The commenter noted that the final rule at issue in *NPRA* promulgated volumes midyear, that were not due until the end of the year. The commenter also pointed to *Monroe Energy v. EPA*,[76] which similarly concluded that EPA's late rule "did not change the legal effect of a completed course of conduct." The commenter suggested that because the SNPRM takes "exempt volumes from previous calendar years … and [reallocates] those exempted volumes to non-exempt refiners, 2-4 years later."

The commenter also distinguished *ACE*, in which EPA promulgated standards for 2014 and 2015 in December 2015. In that action, EPA promulgated standards that reflect actual volumes of renewable fuel that were introduced and available for compliance in those years.

The commenter suggested that the SRE reallocation volume is a "retroactive policy that would take RVOs from past years, to exacerbate rather than minimize the compliance burden for non-exempt refiners."

[75] *Nat'l Petrochem. & Refiners Ass'n v. EPA*, 630 F.3d 145 (D.C. Cir. 2010) ("*NPRA*").
[76] *Monroe Energy, LLC v. EPA*, 750 F.3d 909 (D.C. Cir. 2014).

Response:

We disagree with the commenter's assertion that the SRE reallocation volumes are retroactive. While we intend for the SRE reallocation volumes to be met using excess RINs that are attributable to SREs granted for 2023–2025, the SRE reallocation volumes apply prospectively and can be met using RINs that are currently available in the market. We agree that because we are promulgating the applicable volumes for 2026—which include the SRE reallocation volumes—several months into 2026, the applicable volumes are partially retroactive in effect, and the legal considerations around this topic are explained in more detail in Preamble Section II. Given the timing of this rule, the market retains the ability to respond to the renewable fuel volume requirements we are promulgating in this final rule.

Comment:

A commenter suggested that CAA section 211(o)(2)(B)(ii) as used to establish the SRE reallocation volumes violates the non-delegation doctrine. The commenter pointed to Justice Gorsuch's dissent in *Gundy* and applied such principles to EPA's analysis of the statutory factors in 211(o)(2)(B)(ii), contending that they do not provide an "intelligible principal."

Response:

CAA section 211(o) is not an unconstitutional delegation of legislative authority. A delegation by Congress is constitutional so long as Congress has set out an "intelligible principle" to guide the exercise of authority.[77] In examining a statute for the requisite intelligible principle, the Supreme Court has generally assessed "whether Congress has made clear both 'the general policy' that the agency must pursue and 'the boundaries of [its] delegated authority.'"[78]

The Supreme Court has "over and over upheld even very broad delegations" under that standard.[79] Only twice ever has the Supreme Court found a delegation to be unconstitutional.[80] One "provided literally no guidance for the exercise of discretion," and the other "conferred authority to regulate the entire economy on the basis of no more precise a standard than stimulating the economy by assuring 'fair competition.'"[81]

In the more than 90 years since those two decisions, the Supreme Court has consistently upheld "Congress' ability to delegate power under broad standards,"[82] and "ha[s] 'almost never felt qualified to second-guess Congress regarding the permissible degree of policy judgment that can be left to those executing or applying the law.'"[83] The Supreme Court has upheld statutes authorizing EPA to set national ambient air quality standards at the level that is "requisite" to

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[77] *FCC v. Consumers' Rsch.*, 606 U.S. 656, 673 (2025).
[78] *Id.* (alteration in original) (quoting *Am. Power & Light Co. v. SEC*, 329 U.S. 90, 105 (1946)).
[79] *Gundy v. United States*, 588 U.S. 128, 135 (2019) (plurality opinion).
[80] *Id.*
[81] *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 474 (2001) (discussing *Panama Ref. Co. v. Ryan*, 293 U.S. 388 (1935) and *A.L.A. Schechter Poultry Corp. v. United States*, 295 U.S. 495 (1935)).
[82] *Mistretta v. United States*, 488 U.S. 361, 373 (1989)
[83] *Am. Trucking*, 531 U.S. at 474–75 (quoting *Mistretta*, 488 U.S. at 416 (Scalia, J., dissenting)).

protect public health,[84] authorizing the Secretary of War to determine and recover "excessive profits" from military contractors;[85] authorizing the Price Administrator to fix "fair and equitable" commodities prices;[86] authorizing the Federal Communications Commission to regulate broadcast licensing as "public interest, convenience, or necessity" requires;[87] authorizing the Securities and Exchange Commission to ensure that a holding company's structure does not "unfairly or inequitably distribute voting power among security holders;"[88] and directing the Sentencing Commission to promulgate then-binding Sentencing Guidelines for federal crimes.[89]

The grant of authority to EPA to establish volume requirements falls well within the range of delegations approved by the Supreme Court. "[T]he degree of agency discretion that is acceptable varies according to the scope of the power congressionally conferred."[90] Here, the task that Congress delegated is sufficiently narrow and Congress provided the requisite intelligible principle to guide the Agency's discretion.

Congress did not broadly delegate authority to EPA to determine the RFS applicable volume requirements and leave it at that. Rather, Congress specifically directed EPA to determine the applicable volumes based on a review of implementation of the program in prior years, and an analysis of many specified factors.[91] Congress further specified that in making the determinations, "the applicable volume of advanced biofuel shall be at least the same percentage of the applicable volume of renewable fuel as in 2022."[92] Congress further specified that the applicable volume of cellulosic biofuel "shall be based on the assumption that the Administrator will not need to issue a waiver for such years under paragraph (7)(D)."[93] Congress also provided a "minimum applicable volume of biomass-based diesel" of 1.0 billion gallons.[94]

Other parts of CAA section 211(o) provide direction to EPA about the broader scope of the RFS program, including the parties that must demonstrate compliance with the RFS standards and on what their obligations should be based,[95] as well as definitions of what qualifies as renewable fuel under the program.[96] These provisions apply even when EPA determines the applicable volumes under CAA section 211(o)(2)(B)(ii).

The commenter ignores the conditions in CAA section 211(o)(2)(B)(iii)–(v) and does not explain how these provisions do not provide an "intelligible principle." The commenter instead focuses on the enumerated statutory factors and suggests that because CAA section 211(o) does not "explain which way th[e] factors are supposed to cut," that any decision by EPA would be

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[84] *Id.* at 475.
[85] *Lichter v. United States*, 334 U.S. 742, 785–86 (1948)
[86] *Yakus v. United States*, 321 U.S. 414, 420 (1944)
[87] *Nat'l Broad. Co. v. United States*, 319 U.S. 190, 225–26 (1943)
[88] *Am. Power & Light*, 329 U.S. at 104–05.
[89] *Mistretta*, 488 U.S. at 374–77.
[90] *Am. Trucking*, 531 U.S. at 475.
[91] CAA section 211(o)(2)(B)(ii).
[92] CAA section 211(o)(2)(B)(iii).
[93] CAA section 211(o)(2)(B)(iv).
[94] CAA section 211(o)(2)(B)(v).
[95] CAA section 211(o)(2)(A), (o)(1)(L).
[96] CAA section 211(o)(1)(A)–(J).

arbitrary. We disagree. Although the factors provide EPA considerable flexibility in determining the volumes, a determination that has been articulated by the D.C. Circuit in reviewing EPA's prior actions utilizing the factors CAA section 211(o)(2)(B)(ii),[97] EPA still must consider all the factors articulated and justify the volumes after those considerations.

The context and purpose of the statute provide some further guideposts for EPA in determining the volumes.[98] The renewable fuel volume requirements established in CAA section 211(o)(2)(B)(ii) follow over a decade of statutory tables of renewable fuel applicable volumes determined by Congress that generally increase over time.[99] Indeed, EPA has relied on the statutory tables to inform the applicable volume requirements established under CAA section 211(o)(2)(B)(ii).[100] Thus, the context of the statute indicates that Congress intended to provide EPA the discretion to establish volumes in the later years of the program. Congress could have instead dictated renewable fuel volumes beyond 2022; instead, it decided to leave to EPA, in its fact-intensive technical judgment, to determine the applicable volumes.

Rather than grapple with controlling precedent, the commenter relies primarily on the dissent in *Gundy*. But it is existing Supreme Court precedent that is binding.[101] Besides, even under a broader view of the nondelegation doctrine, it would be permissible for Congress to define the structure of the RFS program, dictate the obligated parties and qualifying renewable fuels, provide an initial set of statutory volume requirements (with EPA authority to waive such volumes in its technical judgment) and establish compliance flexibilities and then leave it to EPA to determine future applicable volumes. To hold even that limited delegation unconstitutional would make much of government unworkable.[102]

Comment:

A commenter suggested that reallocating exempt volume from SRE adjudications that were not subject to notice and comment violates due process. The commenter suggested that the proposed reallocation "frustrates nonexempt parties' prior compliance planning and competitiveness by imposing . . . the additional burden of satisfying those very SRE volumes." "EPA disrupted the competitive posture of the overall refining industry through its excessive approval of small-refinery exemptions in the August 2025 Decisions, which effectively subsidizes small refineries by giving them additional income for every gallon of gasoline and diesel they produce equivalent to the RIN obligation cost." And that the disruption will be amplified by reallocation of projected 2026-2027 exemptions and reallocation of the exempt volume from 2023-2025 through SRE reallocation volumes. The commenter highlighted additional burden for nonexempt refineries that must pass along the costs to consumers while "still competing against the small refineries in their respective markets." The commenter suggested the SNPRM is "insufficient" and only permits comment on the extent to which obligated parties can "shoulder the burden of exempted

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[97] See, *e.g.*, *CBD*, 141 F.4th at 171 (quoting *Sinclair*, 101F.4th at 887)).
[98] *Gundy*, 588 U.S. at 141 (plurality opinion) ("To define the scope of delegated authority, we have looked to the text in 'context' and in light of the statutory 'purpose.'" (quoting *Nat'l Broad. Co*., 319 U.S. at 214)).
[99] CAA section 211(o)(2)(B)(i).
[100] 87 FR 39600 (July 1, 2022); 88 FR 44468 (July 12, 2023).
[101] See *Abbas v. Foreign Pol'y Grp*., 783 F.3d 1328, 1337 (D.C. Cir. 2015); *Big Time Vapes, Inc. v. FDA*, 963 F.3d 436, 447 (5th Cir. 2020).
[102] See *Gundy*, 588 U.S. at 147 (plurality opinion).

[SREs].” The commented noted that the “baseline has been set” – and that there is a material difference between 50 of 100 million gallons or 50% of 4 B gallons, noting the intertwined nature of the volumes, the reallocation of the projected 2026 and 2027 exemptions, and the reallocation of the 2023-2025 exemptions. The commenter suggested that EPA was required to provide notice and opportunity for comment on the SRE decisions themselves, as comments could have resulted in lower exempt volumes and smaller volumes to be reallocated.

Response:

It is questionable whether the Due Process Clause requires EPA to do anything in this RFS standards rulemaking beyond the public process requirements that apply under CAA section 307(d). We are aware of no caselaw reaching such a result, and the commenter did not point to any. Nor did the commenter point to any vested property interest it claims would be deprived by the SRE reallocation volume. There is a presumption that obligated parties must comply with the requirements of the RFS program, and the SRE reallocation volumes are part of those requirements. We recognize that the SRE reallocation volumes increase obligated parties’ obligations under the RFS program, but this is no different than any other applicable volume EPA sets under CAA section 211(o)(2)(B)(ii).

Moreover, this rulemaking imposes standards applicable to all obligated parties in 2026 and 2027, and therefore is not the kind of “quasi-judicial determination by which a very small number of persons are exceptionally affected, in each case upon individual grounds” that might warrant additional procedures under the Due Process Clause.[103]

We do not find that the SRE adjudications themselves are required to be subject to public notice and comment. CAA section 211(o)(9) provides no such requirement. We acknowledge that we have in the past provided an opportunity for comment on EPA’s prior SRE actions, and that we have also promulgated regulations associated with SRE petitions. However, such notice and comment on the adjudications themselves is not required by the statute. We recognize that SREs can have impacts on both the renewable fuels industry and the refining industry, particularly non-exempt refiners in light of our projections of SREs in the percentage standard formulas, and the SRE reallocation volumes. Nevertheless, we find that it is appropriate to require the use of 70% of the 2023–2025 exempted RVOs in 2026 and 2027 for the reasons discussed in Preamble Section IV and elsewhere in this document.

Comment:

A commenter was critical of the supplemental proposal because EPA “cannot accurately estimate the number of SRE reallocation RINs available for 2025, 2026, or 2027.”

Response:

The SRE reallocation volumes are based on actual exemptions for 2023 and 2024. While we have not yet issued decisions on SRE petitions for 2025, 2026, or 2027, we anticipate that the

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[103] *Vermont Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc.*, 435 U.S. 519, 542 (1978); *see also Bi-Metallic Investment Co. v. State Board of Equalization*, 239 U.S. 441, 446 (1915).

same methodology used to adjudicate SRE petitions in the 2025 SRE Decisions Actions will be used to evaluate 2025–2027 SRE petitions. Thus, as discussed in Preamble Section IV.C, we believe our use of average volumes of exempted gasoline and diesel over a three-year period as our projection of exempted volumes of gasoline and diesel in 2025–2027 is appropriate.

Comment:

Several commenters were critical of the timing of the action, particularly in light of the statutory deadline to promulgate the standards 14 months in advance of 2026 and 2027 under CAA section 211(o)(2)(B)(ii). The commenter suggested that obligated parties will be unable to adjust to increased obligations and that obligated parties will have insufficient opportunity for compliance. The commenter noted that the supplemental proposal did not provide mitigation for the harm imposed on obligated parties. The commenter highlighted arguments made on the Set 2 proposal suggesting the rule undermines long-term feedstock contracts and the ability of obligated parties to procure feedstocks and biofuels at reasonable prices.

A commenter indicated that the supplemental proposal fails to mitigate any hardship and actually increases hardship to obligated parties. The commenter pointed to *CBD* where the court ruled that EPA's late Set 1 rule mitigated hardship by setting achievable volumes, providing sufficient time between the final rule and the compliance deadline, and the availability of carry forward deficits. The commenter suggested that the rule will cause "immediate and immense hardship to non-exempt obligated parties." In particular, the commenter suggested that if EPA were to quickly finalize the rule ahead of the 2024 compliance deadline of December 1, 2025, obligated parties will not have time to assess their carryover RIN banks and make adjustments to their obligations, suggesting that the returned 2023 RINs will be useless.

Response:

We recognize that the 2026 standards are late and partially retroactive in effect, and that the 2027 standards are late. However, we have taken steps to mitigate the burdens on obligated parties. Obligated parties will have at least a year from this final rule to plan for compliance ahead of the March 31, 2027, compliance deadline for 2026.

In this action, we have again mitigated hardship by setting achievable volumes (as described in RTC Section 6 and RIA Chapter 7), providing sufficient time between the final rule and the compliance deadline (at least one year), and the availability of carry forward deficits, as well as carryover RINs. We are finalizing this action after the 2024 compliance deadline, and with sufficient time prior to the 2025 compliance deadline of September 1, 2026, to allow obligated parties to make adjustments to their compliance strategies. We note as well that the SRE reallocation volumes are intended to be met with carryover RINs, though we have chosen to reallocate only 70% of the 2023–2025 exempted RVOs to preserve some amount of carryover RINs associated with the exemptions.

As described in Preamble Section II, EPA is permitted to issue standards that are late and even retroactive so long as EPA exercises this authority reasonably. The D.C. Circuit has explicitly evaluated this in the context of EPA establishing standards under CAA section 211(o)(2)(B)(ii), the same authority under which EPA is acting today.[104] We do not find the commenters' suggestions that the SRE reallocation volumes should be treated differently to be compelling in light of our actions to mitigate harm on obligated parties of the lateness of the action.

With respect to suggestions that this rule will undermine long-term feedstock contracts and the ability of obligated parties to procure feedstocks and biofuels at reasonable prices: we disagree with this conclusion. The commenter did not tie such impacts to the SRE reallocation volumes specifically. Many of the impacts projected by such commenters are attributable, in whole or in part, to the proposed IRR provisions, which we are not finalizing in this action. We recognize that other non-RFS incentive programs such as the 45Z credit and State LCFS programs can have significant impacts on the types of feedstocks and renewable fuels supplied to meet the RFS volume requirements, but this action is not finalizing any new programmatic requirements that we anticipate would jeopardize long-term feedstock contracts. For this final rule we have updated our analyses of the types of renewable fuels that we project will be supplied to meet the volume requirements to reflect the projected impacts of the 45Z credit. This has resulted in a significant decrease in our projection of the volume of imported renewable fuels as well as a decrease in our projection of imported feedstocks from outside North America. These revised and updated projections are described in Preamble Section III and RIA Chapter 7.

Comment:

A commenter stated EPA's "stated purpose of the SNRPM is to add volumes to safeguard RIN demand and RIN prices remain high enough to support the production of renewable fuel." The commenter suggested that given this, EPA should have reviewed implementation of the program and analyzed the statutory factors in CAA section 211(o)(2)(B)(ii). The commenter was also critical of the lack of "data transparency or sensitivity analyses," including the lack of an RIA, and the incremental impact of adding the 2023-2025 SRE RINs in addition to the proposed Set 2 volumes.

Response:

We are not establishing the SRE reallocation volume to "safeguard RIN demand" and increase RIN prices. We do not speculate on the RIN price effects of this action. We do believe that the SRE reallocation volumes will preserve the market-forcing nature of the 2026 and 2027 volumes. In the Set 2 supplemental proposal and this final rule, EPA has reviewed implementation of the program and the statutory factors and determined that the majority of the statutory factors are unchanged due to the SRE reallocation volumes being met with carryover RINs, for which there are no impacts of the majority of the statutory factors. One of the statutory factors that we do project will be impacted by the SRE reallocation is the cost of transportation fuel to consumers. The RIA contains EPA's consideration of the SRE reallocation volumes to the extent they impact the analyses therein. Our projection of the impact of the SRE reallocation volumes on the cost of transportation fuel to consumers can be found in RIA Chapter 10.5.4.

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

Comment:

A commenter suggested that the SRE reallocation volumes "punish" all refiners by "inflating their obligations, deepening market inequities, and amplifying compliance instability." The commenter stated that the supplemental proposal risks "market disruptions, higher fuel prices, and potential non-compliance across the refining sector that cannot be mitigated simply by extending the compliance deadline."

Response:

We recognize that SRE reallocation volumes, in conjunction with our projection of SREs to be granted in 2026 and 2027, will result in increased obligations for non-exempt refineries. However, we do not see such requirements as a "punishment" for obligated parties. Rather, the percentage standards ensure the market-forcing nature of the 2026 and 2027 volume requirements, while also setting achievable standards for which compliance is feasible as described in RIA Chapter 7. We do not anticipate that this rule will result in the speculative and unsupported outcomes the commenter suggests.

Comment:

Commenters suggested that EPA is improperly relying on the availability of excess carryover RINs as the justification of the SRE reallocation volumes.

Another commenter stated that EPA cannot increase volumes based on RIN availability. The commenter noted that Congress provided clear direction to evaluate the statutory factors, which do not require consideration of credits, carryover RINs, or reassigning SRE reallocation volumes to future years. The commenter suggested Congress would have included those type of considerations if it wanted EPA to consider them. Commenters suggested that CAA section 211(o)(2)(B)(ii) does not allow EPA to consider past exemptions, particularly in light of the forward-looking nature of the factors. A commenter also suggested that the proposal did not further statutory goals. A commenter was critical of EPA's conclusion that only the "cost to consumers of transportation fuel and the cost to transport goods" would be impacted as a result of the supplemental proposal, and expressed incredulity that EPA might argue that "Congress intended to raise consumer prices."

A commenter suggested that EPA lacked the authority under CAA section 211(o)(2)(B)(ii) to establish SRE reallocation volumes because EPA only pointed to "a review of implementation of the program" as the basis for the SRE reallocation volumes and did not consider the other statutory factors. Another commenter suggested that EPA lacks the statutory authority to establish SRE reallocation volumes because EPA failed to undertake the mandatory analyses under CAA section 211(o)(2)(B)(ii) and that the enumerated statutory factors do not include carryover RINs. The commenter stated that EPA lacked authority to create a volume obligation based on compliance years that have passed, or to increase the volumes in future years on the basis of SREs. The commenter also noted that CAA section 211(o)(2)(B)(ii) requires "review of implementation of the program during calendar years specified in the tables." The tables only specified volumes from 2006-2022, and do not include 2023-2025. The commenter then argued that EPA cannot consider implementation of the program in years after 2022. The commenter made suggestions about the types of information from 2006-2022 that could be considered.

Other commenters questioned EPA's authority to establish SRE reallocation volumes, noting that the CAA does not explicitly grant EPA the power to redistribute compliance obligations in this way.

A commenter suggested that the CAA does not recognize nor permit EPA to set volumes based on the "existence of carryover RINs resulting from SREs." The commenter suggested the SRE reallocation volumes violate the statute's year-by-year structure. The commenter argued the statutory language is clear that EPA is to set "applicable volumes" for "each" renewable fuel. The commenter also noted the lack of statutory language on past SREs. The commenter also notes that the statute is explicitly prospective—directing EPA to set volumes 14 months in advance, with nothing in the statutory language allowing EPA to "look back" to past RFS years after 2022, or consider SREs.

Response:

We disagree; for the reasons described in Preamble Section IV and elsewhere in this document, we are considering carryover RINs in the context of the enumerated statutory factors and have concluded that SRE reallocation volumes are an appropriate mechanism to address the influx of carryover RINs from the 2023–2025 exempted RVOs. As described in Preamble Section II, EPA also has the explicit authority to consider other factors under CAA section 211(o)(2)(B)(ii)(VI). As also discussed in Preamble Section IV, we find it is still appropriate to consider review of implementation of the program in 2023–2025.

We recognize that a number of the statutory factors are forward-looking. This is consistent with the prospective nature of CAA section 211(o)(2)(B)(ii), which directs EPA to set the volumes 14 months in advance of when they will apply. However, SREs granted for past compliance years increase the number of available carryover RINs, and this can have a direct impact on the stringency of standards for future compliance years. The interconnected nature of the compliance years is well recognized in RFS rulemaking actions.[105] Although the RFS program is complied with on an annual basis, carryover RINs (and carry-forward deficits) mean that market conditions and choices by obligated parties in one year can have impacts on subsequent years. We find it appropriate to consider such year-over-year impacts in establishing applicable volumes under CAA section 211(o)(2)(B)(ii). We note as well that the SRE reallocation volumes are additive to three of the four categories of renewable fuel. Thus, similar to the supplemental standards established in 2022 and 2023 associated with the *ACE* remand, we are implementing SRE reallocation volumes within the statutory structure and not creating a new type of volume requirement.[106]

[105] See, *e.g.*, 90 FR 12109 (March 14, 2025); 86 FR 17073 (April 1, 2021).
[106] 87 FR 39600 (July 1, 2022); 88 FR 44468 (July 12, 2023).

Contrary to the commenters' suggestions, we are permitted to consider carryover RINs when determining the applicable volumes under CAA section 211(o)(2)(B)(ii), as we did in the Set 1 Rule and in annual rules prior.[107]

As described in Preamble Section IV, the SRE reallocation volumes are designed to preserve the market-forcing nature of the renewable fuel volume requirements for 2026 and 2027, such that there would not be impacts on other statutory factors, as we anticipate that the volume of renewable fuel needed to meet the renewable fuel volume requirement will be produced and used in the market.

As to impacts on consumer prices, we note that the D.C. Circuit has acknowledged 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."[108]

Comment:

A commenter suggested that not reallocating would "comply with the RFS statute" and directionally help lessen the cost impacts of the RFS program. Other commenters stated that the SREs without reallocation are consistent with the statutory and contemplated by Congress.

Response:

We find that it is appropriate to establish SRE reallocation volumes for the reasons discussed in Preamble Section IV and elsewhere in this document and that we have the statutory authority to establish such volumes. We find that Congress left to EPA's discretion how to account for SREs granted through CAA section 211(o)(9).

Comment:

A number of commenters noted that the only time EPA has added volume associated with prior year RVOs was in response to a court order invalidating EPA's improper use of the general waiver authority. A commenter highlighted that EPA's authority was not "review of implementation of the program" and that EPA's reasoning for the supplemental volume was not excess carryover RINs. The commenter suggested that it was unclear why EPA "has determined that it must reallocate because otherwise there will be too many carryover RINs." Several commenters suggested the SRE reallocation volume, and EPA's justification for it, is in contrast to EPA's authority to establish the *ACE* supplemental volume to "'ensure' that the volume requirements 'are met.'" One commenter stated that the supplemental standards have no impact on EPA's legal rationale for the SRE reallocation volumes or EPA's interpretation of CAA section 211(o)(2)(B)(ii). Another commenter criticized EPA for not explaining its change in reasoning between the *ACE* remand supplemental volumes and the SRE reallocation volumes. The commenter also highlighted EPA's acknowledgement of the availability of carryover RINs as a

[107] 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).
[108] *CBD*, 141 F.4th at 171, citing *Sinclair*, 101 F.4th at 889.

means to mitigate burden for obligated parties in establishing the *ACE* supplemental volume. A commenter noted the difference in magnitude of the SRE reallocation volumes and the supplemental standards associated with the *ACE* remand. The same commenter also noted that the volumes at issue in the *ACE* remand were found in the statutory tables, which reflect Congressionally mandated volumes, whereas the SRE reallocation volume represents renewable fuel volumes established by EPA.

A commenter suggested the D.C. Circuit's opinion in *ACE* also supported an assertion that EPA is not required to consider carryover RINs in setting standards.

The commenter suggests that the current circumstance are quite different from the action establishing the supplemental standards associated with the *ACE* remand in 2022 and 2023. The commenter notes that the *ACE* supplemental standards were in response to a court remand. EPA's SRE reallocation volumes are being established voluntarily by the agency, to address the agency's own decisions to grant exemptions to small refineries. In the *ACE* supplemental standards, EPA increased the overall obligation for all obligated parties – in contrast, the SRE reallocation volumes will shift the burden to nonexempt refineries and thus favoring one segment of industry over the other. The commenter noted EPA's stated authority for the *ACE* supplemental standards was CAA section 211(o)(2)(A)(i) which requires EPA to ensure that transportation fuel contains "at least the applicable volume of renewable fuel;" EPA's authority for implementing the SRE reallocation volumes is the "set authority." The commenter suggested this was improper, and that were EPA to use this authority it would need to reopen the entire proposal for comment instead of just a supplemental proposal. The commenter noted that EPA concluded the *ACE* supplemental volumes were "achievable," and did not rely on the sizeable RIN bank as the sole justification that the volumes could be met, or suggest that the RIN bank would need to be drawn down. The commenter notes that in establishing the *ACE* supplemental standards, EPA acknowledged the volumes could be met through imports or domestic renewable fuel production and EPA calculated costs associated with the volumes. The commenter stated EPA concluded that the SRE reallocation volumes have no costs or impacts on nonexempt obligated parties. The commenter suggested EPA's argument that carryover RINs will discourage reenable fuel production in the future is "misguided." The commenter suggested that EPA's SRE reallocation volumes are particularly problematic given a draw down of the carryover RIN bank in 2025, and expectation of further drawdown in 2026, eliminating a safety valve. The commenter pointed to a Stillwater associates study that indicated a significant reduction in the carryover RIN bank from the Set 2 proposed volumes, without the additional SRE reallocation volume.

A commenter suggested that the legal authority for EPA's supplemental volumes associated with the *ACE* remand was clearly enumerated in the statute, and that it was supported by Congressional direction (in the statutory tables), and judicial order (the D.C. Circuit's remand).

Response:

We recognize that our authority and justification for the SRE reallocation volumes differ from the supplemental standards established to satisfy EPA's obligations under the *ACE* remand in the 2020–2022 RFS Rule and Set 1 Rule. This is intentional and permissible. The mere fact that we are using a different authority does not invalidate our approach. Given the congressional direction in CAA section 211(o)(2)(B)(ii) that EPA determine volumes after 2022, we do not find that, as the commenter suggests, we are unable to establish volumes associated with SREs because they are associated with compliance years for which EPA establishes the volume using the Set authority. In fact, given the discretion provided to EPA by CAA section 211(o)(2)(B)(ii), EPA arguably has greater ability to establish volumes that consider SREs. We note as well that the D.C. circuit's judicial order in *ACE* prompted EPA's promulgation of the supplemental standards. However, the D.C. Circuit's ruling in *Sinclair* also invalidated many SRE denials, and that remand of those exemptions resulted in the large number of SRE adjudications in 2025.[109]

The supplemental standards for 2022 and 2023 as a result of the *ACE* remand were authorized by CAA section 211(o)(2)(B)(i) and CAA section 211(o)(3)(B), which instructed EPA to establish applicable volumes for 2016 and percentage standards. In contrast, the SRE reallocation volumes are being established under our authority in CAA section 211(o)(2)(B)(ii) to determine the applicable volumes of renewable fuel for 2026 and 2027. As described in Preamble Section V, for 2026 and 2027, the applicable volume contains two distinct components: (1) The renewable fuel volume requirement, representing new renewable fuel production in 2026 and 2027, and (2) The SRE reallocation volume, representing 70% of the 2023–2025 exempted RVOs.

This action establishes applicable volume for 2026 and 2027 in the first instance. Though it is partially retroactive in effect for 2026, given that we are finalizing the applicable volumes partway through the year for 2026, and late for 2026 and 2027, for the reasons described in Section II, we have considered the burdens caused by the lateness on obligated parties and have provided compliance flexibilities, as well as ensured that the applicable volumes can been met as described further in RTC Section 6 and RIA Chapter 7. Although this action is intended to reduce the volume of available carryover RINs, we find that it is appropriate to do so in these unique circumstances given the large volume of carryover RINs newly available as a result of the 2023–2025 SREs. We also note that we are not requiring the retirement of all RINs associated with the 2023–2025 exempted RVOs—only 70%, for the reasons discussed in Preamble Section IV and elsewhere in this document. This will maintain some carryover RINs as a compliance flexibility.

We do not find that the approach we are taking in this action would be required in any particular circumstance in the future, and we maintain our position, as described in RTC Section 7.2 and Preamble Section V, that we do not plan to make up for additional exempted volume if the total exempted volumes for 2026 and 2027 exceeds that which we project in this final rule. The same is also true for 2025 and earlier years—when we issue decisions on all pending 2025 SRE petitions and any additional 2023 or 2024 SRE petitions in the future, we do not plan to adjust the SRE reallocation volumes, or issue new SRE reallocation volumes. Instead, we find that the confluence of factors before us today, including the known significant amount of SREs granted (or projected to be granted) for 2023–2025 after the percentage standards were established, and the issuance of a final rule establishing volumes for 2026 and 2027, justify establishing SRE reallocation volumes at this time.

[109] *Sinclair v. EPA*, 114 F.4th 693 (D.C. Cir. 2024).

Comment:

A commenter suggested that the statutory structure, including the annual basis of the standards and requirements for each "calendar year," indicates that EPA is not consistent with the supplemental proposal, and diminishes certainty and predictability for the regulated industry.

Response:

EPA recognizes that the regulatory structure of the RFS program requires standards and compliance on an annual basis. However, we find that in certain circumstances, EPA is able to consider and even require additional renewable fuel use associated with prior-year requirements. Prior actions by EPA along these lines have been upheld.[110]

Comment:

A commenter suggested EPA's authority to adjust the annual percentages standards derives from CAA section 211(o)(3)(C), which provides the framework that EPA must follow to calculate the percentage standards. The commenter suggests EPA is only able to adjust the percentage standards to account for renewable fuel used by exempt small refineries, and to prevent the imposition of redundant obligations on refiners and importers. The commenter pointed to EPA's statements in RFS2 on CAA section 211(o)(3)(C)(ii). The commenter also noted that the D.C. Circuit's opinion in *Sinclair v. EPA* upholding EPA's prior actions reallocating SREs in the percentage standards relied on *Chevron* and that *Chevron* was overturned in *Loper Bright* and did not speak to EPA's authority to establish volume requirements for SRE reallocation.

Another commenter suggested the supplemental proposal contradicts the specific language in CAA section 211(o)(3)(C)(i) which directs EPA to make adjustments to prevent the imposition of redundant obligations on refiners, blenders, and importers. The commenter suggested reallocating obligations from previous years, which non-exempt refiners were already required to meet, back onto the non-exempt refiners to satisfy again in the future violates this provision.

Response:

At the onset, as confirmed by the D.C. Circuit, CAA section 211(o)(3) is not applicable after 2021 (as applied in establishing 2022 percentage standards).[111] As stated in the Set 1 Rule, "[o]n its face, this language does not apply to rulemakings establishing obligations for years subsequent to 2022. Therefore, EPA is not bound by this language for those years."[112] This is true

[110] See *Sinclair v. EPA*, upholding EPA's supplemental standard associated with the *ACE* remand and *NPRA v. EPA*, upholding EPA's action combining the 2009 and 2010 BBD standards. *Sinclair*, 101 F.4th at 896; *NPRA*, 630 F.3d at 158.
[111] *Clean Fuels Alliance America v. EPA*, No. 20-1107, 2026 U.S. App. LEXIS 7406, at *7 (D.C. Cir. March 13, 2026) ("Further, the mandate for EPA to achieve the applicable volume goals specifically by means of percentage standards expired at the end of 2021.")
[112] 88 FR 44468, 44478 (July 12, 2023).

for all subparagraphs of CAA section 211(o)(3), which includes bounded dates in two of the three subparagraphs (CAA section 211(o)(3)(A)–(B)).

Even if CAA section 211(o)(3)(C) did apply, it does not limit EPA's authority to establish SRE reallocation volumes. EPA has explained that while CAA section 211(o)(3)(C)(ii) speaks to adjustments in the volume requirements as a result of renewable fuel used by exempt small refineries, EPA addressed this provision in the RFS2 Rule (as noted by one of the commenters), stating:

> [w]hatever renewable fuels small refineries and small refineries blend will be reflected as RINs available in the market; thus there is no need for a separate accounting of their renewable fuel use in the equations used to determine the standards. We proposed and are finalizing this value as zero.[113]

Thus, because we established the RIN system, which allowed for the trading of credits associated with renewable fuel used by small refineries, it was not necessary at that time to account for any renewable fuel use by exempt small refineries. This continues to be true. As stated in 2022, this provision indicates that Congress expressly considered the impacts of SREs on the annual standard-setting process, chose to mandate this sole adjustment, and entrusted discretion to make other potential adjustments to the Agency.[114]

CAA section 211(o)(3)(C)(i) requires that, when determining the percentage standards, EPA must make adjustments to "prevent the imposition of redundant obligations on any person specified in [CAA section 211(o)(3)(B)(ii)]." Setting aside the fact this provision is no longer in effect, the commenters do not explain with reasonable specificity what they think this provision means or why it prohibits EPA's approach to SRE reallocation volumes in this rule. In any event, we are not imposing redundant obligations on any obligated party.[115] Rather, all obligated parties are subject to the same percentage standards, and none are required to comply with the same standard multiple times.

As in the 2020–2022 RFS Rule, we again find that CAA section 211(o)(3)(C), while providing some direction to EPA, is not the limit on how EPA can account for SREs. CAA section 211(o)(2)(B)(ii), the authority under which EPA is establishing the SRE reallocation volumes, provides that EPA is to determine the volumes, and in doing so, EPA has considered the future rate of annual production and analyzed the impact of an increased percentage standard on the cost of the program.

Comment:

A commenter suggested that EPA's discretion to balance the statutory factors is not unlimited, and EPA must set the volume requirements at the maximum volume of renewable fuel use that can be achieved in response to the RFS's incentives, including reallocation.

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[113] 74 FR 14670, 14717 (March 26, 2010).
[114] 2020–2022 RFS Rule RTC at 139.
[115] 2020–2022 RFS Rule RTC at 143.

Response:

We disagree that CAA section 211(o)(2)(B)(ii) requires EPA to set the volume requirements at the maximum volume of renewable fuel use that can be achieved. As discussed elsewhere, the statute provides EPA significant discretion to weigh and balance the statutory factors.

Comment:

Several commenters urged EPA to include a volume restoration mechanism to preserve high volumes or increase requirements if SRE reallocation is invalidated.

Response:

We decline at this time to implement such a mechanism. If the SRE reallocation volumes are invalidated, we will assess the circumstances, as well as any legal conclusions by a court, at that time.

7.3.2 Proposed SRE Reallocation Volumes

Comment:

Some commenters strongly supported 100% reallocation, suggesting that doing so would protect RIN prices, support investment in new biofuels projects, and ensure demand for new renewable fuel production. Commenters also suggested that any less than 100% reallocation would be inconsistent with the statute, as it does not ensure the volumes are met.

Many commenters supported full reallocation for many reasons including: to maintain the integrity of RFS program; to provide market stability and certainty; to preserve statutory intent and objectives for renewable fuel usage, economic development, U.S. energy security and the environment; to promote American energy dominance; to address regulatory uncertainty from August 2025 SRE decisions; to preserve the RVOs in the June proposal; to send strong market signals and continued investment in biofuels, including growth in feedstock supplies and expansion of crush capacity; and to support farmers and protect and strengthen the rural economy. Commenters suggested that reallocating less than 100% would result in the loss of RINs and weakened demand for biofuels, including reduced RIN prices, and reduced domestic soybean oil utilization. A commenter quantified recent economic losses for corn farmers, and indicated anything less than 100% reallocation would result in additional harm to corn farmers.

Commenters pointed to 2016-2019, when a large number of SREs were granted and not reallocated resulting in ethanol revenue losses. Commenters suggested that burdens and impacts on non-exempt refineries would be minimal due to RIN cost passthrough.

Several commenters that supported reallocation also supported splitting the volume between 2026 and 2027 to lessen market disruption.

Response:

We have considered the benefits of 100% reallocation and weighed them against the important market benefits provided by carryover RINs and determined that it is appropriate to reallocate 70% of the 2023–2025 exempted RVOs for the reasons discussed in Preamble Section IV.

Comment:

Multiple commenters noted that the 50% co-proposal was only supported by speculation as to what obligated parties may do in response and that EPA provided no analysis to support the statement that obligated parties have, or are likely to “hold, rather than use” carryover RINs. The commenter stated that EPA was required to present the data and methodology for its determinations at proposal for the public to provide meaningful comment. The commenter stated that retaining a RIN bank is not a proper basis to reduce the SRE reallocation volumes from 100%. The commenter suggested that deficits may be eliminated by small refineries receiving exemptions, and that the proposal did not address lost volume from years prior to 2023. The commenter argues that there is not a statutory basis to reallocate less than 100% and that EPA has not articulated a statutory justification or policy reason for doing so. A commenter suggested

EPA did not explain how 50% reallocation would meet EPA's obligations to ensure the volume requirements.

Response:

We are finalizing 70% reallocation for the reasons discussed in Preamble Section IV and elsewhere in this document.

As compliance decisions are made by obligated parties on an individual basis, we are unable to say with certainty what obligated parties will do. However, we do anticipate that some obligated parties will hold carryover RINs. Additionally, we find that given the partially retroactive nature of the 2026 standards, it is appropriate to permit the retention of some amount of carryover RINs as a compliance flexibility for obligated parties.

We recognize that this final rule does not address exempted RVOs from years prior to 2023. However, as noted in the Set 2 supplemental proposal, such RINs are unlikely to impact the 2026 and 2027 standards we are establishing in this action because the RINs returned for years prior to 2023 were expired.

As we are not acting under CAA section 211(o)(2)(A) or 211(o)(3)(B)(ii), we do not need to "ensure" the volume requirements. Nevertheless, we anticipate that requiring 70% of the 2023–2025 exempted RVOs in the SRE reallocation volumes will result in the renewable fuel volume requirements being realized.

Comment:

A commenter conducted an analysis via Charles River Associates using refinery cost data to evaluate the impact of SREs on cleared market prices and corresponding gross margins in three scenarios: No SREs are granted, all small refineries are granted SREs but none of the exempted volume is reallocated, and all small refineries are granted SREs and all the exempt volume is reallocated. The study concluded that reallocation was likely to result in increasing production of obligated fuels by small refineries and decreasing production by larger non-exempt refineries. The study suggests that this may result in higher consumer costs in markets without small refineries, particularly in high RIN price scenarios. The study also found that even without reallocation, SREs "shift[] the marginal price-setter from a small refinery to a large refinery, resulting in more than 100% increase in profit for small refineries." The commenter suggested EPA failed to consider the impact on consumers and refiner's margins.

Response:

EPA recognizes that there is a financial benefit for small refineries that receive SREs and that it is possible that these exemptions could provide a competitive advantage for the refineries that receive them. While these benefits are likely meaningful for the individual small refineries, we do not expect that they will have significant market impacts on the price of transportation fuels in the U.S. Any shift in production from large refineries to exempt small refineries is expected to be small in magnitude. To be eligible for an SRE, a refinery must have received the initial blanket exemption for small refineries; newly constructed or newly obligated refineries are not eligible to petition for an SRE.[116] SREs are also limited to refineries with an average aggregate daily crude oil throughput of 75,000 barrels per day or less, limiting the ability for small refineries to increase production and still qualify for the exemption. In reality, the total production capacity at many small refineries is much smaller than the 75,000 bpd limit. Furthermore, EPA has historically not issued decisions on SRE petitions until after the compliance year is over; thus, small refineries do not actually know whether they are going to be exempted during the compliance year. Because the potential for exempted small refineries to increase their production of transportation fuel is very limited, we do not expect that a limited shift in transportation fuel production from larger refiners to exempt small refineries would significantly change the market price of transportation fuel, which is set by the price of the marginal gallon fuel supplied.

EPA has also assessed the projected fuel price impacts of the SRE reallocation volumes (see RIA Chapter 10.5.4). We estimate that the price impacts of the SRE reallocation volumes are relatively small—less than 1¢ per gallon of gasoline and diesel in 2026 and 2027. Consideration of the impact of SREs on refiner margins is beyond the scope of this rule.

Comment:

A commenter conducted an analysis using the WAEES model to assess the use of BBD under several scenarios, including 0%, 50%, and 100% SRE reallocation, and including the proposed IRR provisions. The commenter noted effects of the analysis on petroleum fuel demand (largely due to a shift from AEO2023 to AEO2025) and noted a decrease in the amount of BBD needed to backfill the implied conventional fuel requirement. The commenter noted increased demand for BBD in the100% reallocation scenario, as well as increased feedstock prices and feedstock demand. In the 50% and 0% reallocation scenarios, the commented noted decreased demand for BBD, with corresponding decreasing feedstock prices.

Response:

The study conducted by the commenter, while including variables that are not being finalized in this action like the proposed IRR provisions, is generally consistent with EPA's understanding that a higher percentage of reallocation of the 2023–2025 exempted RVOs results in higher demand for biofuels. However, the commenter's analysis does not appear to have considered whether obligated parties holding carryover RINs would use these RINs for compliance in 2026 or 2027 or alternatively hold these RINs for use in future years. Instead, the study appears to have made a simplifying assumption that all carryover RINs available to obligated parties as a result of the 2023–2025 SREs would be used in lieu of renewable fuel in 2026 and 2027. Thus, the commenter's study represents a somewhat worst-case scenario for biofuel demand rather than an evaluation of how obligated parties might use available carryover RINs. EPA's decision to reallocate 70% of the 2023–2025 exempted RVOs reflects our assessment of the likelihood that obligated parties will use these excess RINs to meet their compliance obligations in 2026 and 2027 and our efforts to balance competing interests as discussed in Preamble Section IV.

[116] See, *e.g.*, August 2025 SRE Decisions Action Section III.A and B.

Comment:

Some commenters agreed with EPA that additional RINs from SREs could have a deleterious effect on current and proposed volume requirements. A commenter also argued that insufficient reallocation would result in the 2026 and 2027 volumes not being achieved, noting a decrease in RIN and renewable fuel demand as a result of carryover RINs. The commenters stated full reallocation would ensure demand certainty for agricultural feedstocks and renewable fuels. Many commenters note that decreased demand due to excess carryover RINs limits biofuel value chain expansion and diminishes potential domestic market growth for U.S. soybeans. Another commenter suggested that SREs should not reduce the demand for fuel and feedstocks, and that reduction in demand was already apparent in 2025 due to SREs and carryover RINs. The commenter stated full reallocation is feasible and supported by the size of the carryover RIN bank and past production in the renewable fuel industry.

Response:

We discuss our justification for finalizing the SRE reallocation volumes in Preamble Section IV. However, we disagree with the commenters who suggested that only 100% reallocation can achieve the desired outcome of maintained demand for new renewable fuel production and use in 2026 and 2027. We are finalizing advanced biofuel and BBD volumes in this rule that represent the maximum amount of renewable fuel that can be produced domestically, which will continue to send strong demand signals for U.S. soybean and soybean oil production.

Comment:

A commenter suggested that EPA could not justify failure to reallocate exempt volumes by a desire to maintain or grow the number of available carryover RINs. The commenter suggested any justification would be arbitrary without an analysis of the appropriate number of available carryover RINs. Other commenters suggested that carryover RINs are not required by the statute.

Response:

While maintaining some amount of carryover RINs is part of our justification for 70% reallocation, we do not do so under an argument that we seek to maintain the number of available carryover RINs at any particular amount. Instead, we seek to preserve the availability of carryover RINs as a compliance flexibility for obligated parties, particularly in light of the late issuance of the 2026 and 2027 standards, as discussed in Preamble Section IV.

Comment:

Some commenters suggested that the SRE reallocation volumes would increase costs for nonexempt refineries.

Response:

Commenters who suggested that the SRE reallocation volumes would increase costs for nonexempt refiners did not provide analysis to support such assertions. We recognize that SREs have a benefit for the refineries that receive them, as discussed elsewhere in this document.

Comment:

A commenter suggested that EPA's statutory analysis failed to address the amount of exempted volumes in 2023–2025 that were not produced and blended in those years, and thus did not generate the RINs assumed to be available. The commenter said EPA should apply the logic of *API v. EPA* and apply a "neutral aim at accuracy" and not assume reallocation will lead to increased production in 2026 and 2027. Another commenter argued that reallocation unfairly forces compliant refiners to pay for waivers granted to their competitors for volumes they didn't produce.

Response:

We disagree with the premise asserted by the commenter; throughout most of 2023–2025, the market did not know that SREs were likely to be granted. EPA did not project any exempted volumes in the Set 1 Rule that established the 2023–2025 standards and throughout all of 2023 and 2024 (and most of 2025), EPA did not grant any SREs. Thus, there was no reason for the market to act in any manner other than to assume that no SREs would be granted. RIN generation data supports this. The number of RINs generated and available for compliance (after accounting for RINs retired for exported renewable fuel and reasons other than to demonstrate annual compliance) was approximately 22.2 billion RINs in 2023 and 23.6 billion RINs in 2024.[117] These numbers are significantly higher than the volume requirements EPA established for those years (20.94 billion and 21.54 billion RINs, respectively). Preliminary data from 2025 suggests that the actual supply of RINs in 2025 may fall slightly short of the 2025 volume requirements, but in aggregate the total quantity of renewable fuel produced and used in 2023–2025 is projected to exceed the volume requirements for these years before considering the impact of any SREs on the actual obligated volumes. Thus, we do not believe that there are any "exempted volumes in 2023–2025 that were not produced and blended," nor do we believe it would even be appropriate to attempt to account for this unknowable volume even if it did exist.

The Court's directive that EPA take a neutral aim at accuracy applies when EPA determines the projected volume available when using the cellulosic waiver authority. It is not properly applied here. We are finalizing 70% reallocation for the reasons discussed in Preamble Section IV and elsewhere in this document.

[117] RIN data from EMTS. See summary of RIN generation and retirements in "RIN Generation Data 2012 to 2024," available in the docket for this action.

Comment:

Some commenters argued that the Set 2 supplemental proposal is arbitrary and capricious because it would disproportionately harm small refineries that did not or will not receive full exemptions and could lead to refinery closures.

Response:

In this final rule, we have considered impacts on small entities as described in RTC Section 12.1 and RIA Chapter 11. While we agree that small refineries that do not receive full relief will need to comply with higher standards in 2026 and 2027 as a result of the SRE reallocation volumes in this final rule, we do not find that such compliance would result in disproportionate harm. Small refineries will have the opportunity to demonstrate disproportionate economic hardship in their individual SRE petitions, and EPA will evaluate those petitions at that time, such that parties that demonstrate DEH will receive exemptions.

As to the commenter's assertion that they must purchase RINs, we discuss this concept in RTC Section 9. But as discussed elsewhere, in general, we find 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.[118] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs.

Comment:

A commenter was critical of the SRE reallocation volumes, which the commenter suggests "reassigns RFS blending obligations from one group of US refiners to another" and ultimately increases costs for consumers. Commenters noted high inflation, and affordability concerns for American families, with some suggesting the SRE reallocation volume would exacerbate these concerns. Another commenter was critical of the lack of an RIA in the SNRPM, pointing to OIRA comments that such analysis was needed.

Other commenters suggested increased fuel costs would be significant as a result of the SRE reallocation volumes.

Response:

The RIA for this final rule includes analysis of the SRE reallocation volumes to the extent it is appropriate. We have considered the statutory factors and costs of this action. As for commenters that suggested that this rule would increase costs for consumers, we acknowledge costs of this

[118] 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 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.

action in RTC Section 9 and RIA Chapter 10. Those analyses assess the impact of the applicable volumes for 2026 and 2027, including the SRE reallocation volumes. As described in RIA Chapter 10.5.4, EPA has also assessed the projected fuel price impact of the SRE reallocation volumes. We estimate that the price impact of the SRE reallocation volume is relatively small, less than 1¢ per gallon of gasoline and diesel in 2026 and 2027.

Comment:

Some commenters predicted shortfalls in the 2025 standards, and that this would result in a drawdown in the number of carryover RINs available. The commenter suggested this, in conjunction with SRE reallocation volumes, would significantly increase RIN prices.

Response:

EPA does not speculate on future RIN prices. The actual number of RINs needed for 2025 compliance will not be known until after all obligated parties submit their annual compliance reports. The actual compliance obligation will be a function of actual gasoline and diesel production in 2025 and EPA's decisions on the 30+ outstanding 2025 SRE petitions that will likely result in some volume of exempted RVOs. Thus, we believe it is not appropriate to speculate as to whether the number of available carryover RINs will ultimately increase or decrease after compliance with the 2025 standards.

Comment:

A commenter suggested that the SNPRM is arbitrary and capricious because the exempt volumes are unlikely to remain in the market. The commenter pointed to historical compliance data indicating that the RFS program consistently achieves or exceeds the RVOs, and that there are often carryover RIN volumes. The commenter suggested the market is able to self-correct. The commenter also pointed to 2023 and 2024 as examples of the market exceeding the full RVOs.

Another commenter suggested that the idea that obligated parties will use carryover RINs rather than new renewable fuel is speculative.

Response:

While we recognize that the market achieves or exceeds the volume requirements in some years, in other years the use of renewable fuels falls short of the volume requirements (*e.g.*, use of renewable fuels was lower than the volume requirements in 2018, 2019, and 2022). In these years, obligated parties used prior-year RINs (effectively reducing the number of carryover RINs available for future years) and deficit carryforward provisions to meet their compliance obligations. We do not believe that the market would meet or exceed the volume requirements with renewable fuel produced and used in 2026 and 2027 without the SRE reallocation volumes. All market participants are now aware of the 2023–2025 exempt RVOs and can reasonably project the impact these exemptions will have on the number of available carryover RINs. Without reallocation, obligated parties are likely to use carryover RINs instead of new renewable fuel for compliance with the 2026 and 2027 standards, likely resulting in the market supplying less renewable fuel. In contrast, in 2023 and 2024, EPA projected no SREs, and thus the market supplied sufficient volumes of renewable fuel to meet the standards.

We recognize that there is uncertainty as to whether obligated parties will ultimately use carryover RINs or higher volumes of renewable fuels to meet their compliance obligations in 2026 and 2027. Projecting this with certainty is inherently complex, as carryover RINs are held by individual companies that will make these decisions based on factors relevant to their individual companies and their expectations about the stringency of the RFS standards in future years. Nevertheless, consistent with observations in past years, we believe it is reasonable to project that obligated parties are more likely to use carryover RINs (rather than higher volumes of renewable fuel) when the number of available carryover RINs is relatively high, as we project will be the case in 2026 and 2027 absent the SRE reallocation volumes.

Comment:

A commenter suggested EPA failed to consider impacts on food prices as a result of the SRE reallocation volumes, including the potential need to increase imports, and shift of feedstocks from food to biofuels.

Response:

We expect the SRE reallocation volumes will be met with carryover RINs, and thus we do not anticipate impacts of food prices as a result of the SRE reallocation volumes themselves. We have considered the impact of the volume requirements on food prices as discussed in RIA Chapter 9.4 and RTC Section 9.

Comment:

A commenter was critical of the SNPRM, suggesting that the proposal failed to adequately balance the goals of the RFS program and would impose economic harm on independent refiners and American consumers.

Another commenter stated that reallocating volumes punishes all refiners by inflating obligations, deepening market inequities, and amplifying compliance instability. A different commenter suggested that SRE reallocation volumes are shifting compliance costs onto small and independent refiners.

Response:

We disagree with the commenters. The SRE reallocation volumes properly balance the need to realize the 2026 and 2027 volumes, with the interests of obligated parties to maintain compliance flexibilities.

We respond to comments about refineries, compliance costs, and consumer prices in RTC Section 9. While the SRE reallocation volumes will increase obligations, these obligations are intended to be met with available carryover RINs and we anticipate that compliance with the volumes will be feasible across the market.

Comment:

A commenter stated that the SRE reallocation volumes would increase RIN prices and compliance costs for non-exempt refiners, create significant challenges for fuel marketers that do not blend products, and introduce additional market volatility. The commenter further argued that fuel prices would also increase, especially for branded marketers who cannot easily switch suppliers to mitigate costs.

Response:

EPA has evaluated the projected impact of the SRE reallocation volumes on the fuel prices (see RIA Chapter 10.5.4). These impacts are projected to be relatively small—0.5¢ and 0.6¢ per gallon in 2026 and 2027, respectively. We disagree with the commenter that these impacts will disproportionately impact fuel marketers that do not blend renewable fuels. EPA's analysis, supported by outside parties, has demonstrated that on average at the nationwide scale, fuel wholesalers discount the sales price for blended fuels by the value of the RINs associated with any renewable fuels the blend and therefore marketers that purchase fuels blended with renewable fuels are not disadvantaged over marketers that blend renewable fuels and separate RINs.[119]

EPA also disagrees with the commenter's statements that branded marketers will be disadvantaged relative to unbranded marketers. We recognize that branded marketers often enter into long-term contracts for fuel supplies. These supply agreements, however, are rarely if ever fixed-price contracts. Instead, these contracts are generally indexed to prices in major fuel hubs and thus respond to changing market dynamics such as changes in crude oil prices or RFS obligations. Even if branded marketers are restricted to some degree by their fuel supply contracts, we do not believe it would be reasonable to limit the SRE reallocation volumes to accommodate these private contracts.

Finally, we disagree with the commenter's claims that the SRE reallocation volumes will introduce additional market volatility. We recognize that the RFS program operates as a market-based system and that RIN prices can and do change in response to broad market factors. The overall effect of the SRE reallocation volumes is a marginal increase in the stringency of the RFS obligations for 2026 and 2027. We do not expect that this incremental obligation would cause excessive market volatility, nor has the commenter provided a reasoned argument for why they believe this to be the case.

[119] Id.

Comment:

Several commenters pointed to analysis conducted by Turner Mason Company, indicating increased compliance costs associated with the SRE reallocation volume of $10–12 billion.

Response:

We have assessed this study and disagree with its findings and methodology. The study calculates compliance costs based solely on RIN prices. As noted elsewhere, 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.[120] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs.

Apart from an obligated party's ability to recover the cost of the RINs they acquire—whether by blending or purchasing separated RINs—the compliance costs estimated by the commenter is significantly higher than the cost estimated by EPA. This appears to be because the Turner Mason study referenced by the commenters made two major assumptions that are inconsistent with EPA's projection in this final rule. First, the study appears to assume that the SRE reallocation volumes are met with additional production and use of renewable fuels in 2026 and 2027, rather than through the use of carryover RINs. This assumption increases the cost of the SRE reallocation volumes by increasing the price of the feedstocks and renewable fuels used to produce the marginal gallon of renewable fuel. Second, the study appears to assume that the proposed IRR provisions apply in the 2026 and 2027 compliance years, which, as described Preamble Section I, EPA is not finalizing in this rule. This significantly increases the study's estimated compliance costs as it shifts the marginal renewable fuel to imported biofuels (or biofuels produced from imported feedstocks) and two gallons of imported fuels are required to provide the same number of RINs as a single gallon of domestic biofuel (or a gallon of imported biofuel without the proposed IRR provisions).

EPA's estimates of the fuel price impacts of the SRE reallocation volumes are much lower than those of the commenter. As described in RIA Chapter 10.5.4, we estimate that the SRE reallocation volumes will increase fuel prices by 0.5¢ and 0.6¢ per gallon in 2026 and 2027, respectively. In total, these fuel price increases represent a cost of approximately $2 billion across these two years.[121] EPA has considered this cost, along with our review of the implementation of the RFS program to date and the other statutory factors, in determining that the volumes we are finalizing in this action, including the SRE reallocation volume, are appropriate.

[120] Id.

[121] EPA estimated this total cost by multiplying the estimated per gallon price impacts ($0.005 and $0.006 per gallon in 2026 and 2027, respectively) by the projected volume of obligated gasoline and diesel (173 and 171 billion gallons in 2026 and 2027, respectively).

Comment:

A commenter pointed to an analysis by the Energy Policy Research Foundation Inc. ("EPRINC") that suggested that the costs of the RFS program will rise significantly in 2026 and 2027. The commenter noted several factors that contribute to this, including a reduced carryover RIN bank, reduced RIN-value for imported biofuels, and high volume requirements.

The commenter suggested that the SRE reallocation volumes would increase the price of RINs, and thus the cost of the program by an additional $5.3–6 billion. Other commenters, citing the same study, concluded that overall, the SRE reallocation volumes and the renewable fuel volumes will add an additional 50¢ per gallon to consumer fuel costs.

Response:

The commenters did not provide a copy of the EPRINC study in its comments or otherwise provide sufficient information for EPA to obtain a publicly available version of the full study. Thus, EPA is unable to fully engage with the study's conclusions given EPA is not aware of the study's methodology. The public information we could find seemed to rely on projected RIN costs as the basis to determine the costs of the program. As discussed in other responses in this section, we do not believe RIN prices reflect the societal costs or net fuel price impacts of the RFS volume requirements. No other information about the methodology used or assumptions made in the study were provided.

EPA has done its own analysis of the impact of the SRE reallocation volumes and concluded that the price impact of the SRE reallocation volume is less than 1¢ per gallon of gasoline or diesel fuel, as described in RIA Chapter 10.5.4. This price impact would result in a total increase in fuel costs to consumers of approximately $2 billion in 2026 and 2027 combined. We have considered this cost, along with our review of the implementation of the RFS program to date and the other statutory factors, in determining the applicable volumes for 2026 and 2027 in this final rule.

Comment:

A commenter suggested reallocation "rewards those exempted from complying" while burdening obligated parties who actively comply.

Response:

We note that EPA is required to grant SREs under CAA section 211(o)(9) when the statutory criterion of disproportionate economic hardship is met. Thus, it is with congressional direction that EPA exempts small refineries. While we recognize that obligated parties who are not exempt will continue to have compliance obligations under this final rule, we do not find this to be a "burden" but rather a fundamental aspect of the RFS program.

Comment:

A commenter suggested that 50% reallocation lacks a clear analytical basis.

Response:

We are finalizing 70% reallocation of the 2023–2025 exempted RVOs for the reasons discussed in Preamble Section IV.

Comment:

A commenter suggested that partial reallocation could stall investment in oilseed processing and renewable diesel production.

Response:

We do not believe that the SRE reallocation volumes we are finalizing in this rule will stall investment in oilseed processing and renewable diesel production. Rather, the renewable fuel volumes we are finalizing in this rule, in conjunction with the SRE reallocation volumes, will encourage investment in oilseed processing and renewable diesel production within the U.S.

Comment:

A commenter suggested that staggered or incomplete adjustments to the volumes would reduce the benefits of reallocation and perpetuate RIN price volatility.

Response:

We intend for this rule establishing SRE reallocation volumes for 2026 and 2027 to be our complete action to address the 2023–2025 exempted RVOs. Thus, we do not believe it will result in RIN price volatility as we do not intend on taking any additional actions to address the 2023–2025 exempted RVOs.

Comment:

A commenter suggested that the justification at proposal was contradictory because EPA cannot claim there is a carryover RIN issue if reallocating SREs can be fulfilled with carryover RINs.

Response:

As explained in Preamble Section IV, the SRE reallocation volumes are intended to be met with through retirement of excess RINs attributable to the 2023–2025 SREs such that the availability of carryover RINs does not result in less renewable fuel being produced and used in 2026 and 2027.

Comment:

A commenter suggested that the SNPRM ignored that the carryover RIN bank was "depleted," and that EPA must also consider carry forward deficits.

Response:

In this action we have provided an updated analysis of the availability of carryover RINs in Preamble Section III. This analysis shows that, even after accounting for RIN deficits, there was a significant increase in the number of available carryover RINs as a result of the 2025 SRE Decisions Actions and thus carryover RINs have not been "depleted."

Comment:

A commenter suggested that EPA should consider the past relationship between RIN prices and the number of carryover RINs when determining the appropriate level of reallocation.

Response:

EPA is unaware of any relationship that exists between RIN prices and the number of available carryover RINs. RIN prices are tracked on a daily or weekly basis by various public and private sources. RIN prices are impacted by numerous factors (*e.g.*, prices of crude oil and agricultural commodities) and can vary significantly within a calendar year. Conversely, there is no daily (or even weekly or monthly) assessment of the availability of carryover RINs. EPA itself only assesses the number of carryover RINs after annual compliance reports are submitted, which is at least several months after a compliance year is over. Furthermore, the 2025 SRE Decisions Actions have resulted in significant retroactive increases to the number of carryover RINs calculated to be "available" for previous compliance years, even though those carryover RINs were not actually available during the compliance year itself. Thus, it is unclear how such a relationship between RIN prices and carryover RINs would be developed. The commenter does not provide any data or analysis to support their comment, nor do they indicate how they believe EPA should consider this relationship if it existed.

Comment:

A commenter suggested that EPA should establish volumes that maintain available carryover RINs in each category going into 2028.

Response:

While we have not designed the applicable volumes in this manner, we anticipate that carryover RINs will be available in each category after obligated parties comply with their 2026 and 2027 obligations.

Comment:

Several commenters noted the impact of the lateness of this rulemaking action on the market's ability to respond, suggesting that finalization within 2026 would negatively impact the ability of the industry to exceed EPA's predictions.

Response:

We discuss the timing of this rule in Preamble Section II and RTC Section 6. We note that this rule is being promulgated early enough in the 2026 compliance year such that the market should have sufficient time to react to the applicable volumes we are promulgating, including the SRE reallocation volumes.

Comment:

A commenter requested that EPA state its assumptions regarding carryover RINs, deficit carryforward, pending compliance reporting for 2024, and potential changes to 2025 obligations. The commenter also suggested EPA consider potential legal challenges to SRE decisions.

Response:

In this rule, we have provided an updated projection of the number of available carryover RINs in Preamble Section III.F. This projection is based on 2024 RFS compliance data (including RIN deficits) and accounts for the carryover RINs reintroduced into the market as a result of the 2025 SRE Decisions Actions. We recognize that there are currently pending legal challenges to the SRE decisions. However, we are unable to predict how those challenges are likely to resolve, nor would it be appropriate for us to speculate on the outcomes of those challenges, and thus, we are unable to change our SRE reallocation volumes in light of those challenges.

Comment:

A commenter suggested that if EPA reallocates SRE volumes, it should exclude projected volumes of renewable fuel that would be blended without the RFS program from the calculation. The commenter also suggested that no more than 50% of D4 volumes should be subject to reallocation to maintain refinery viability and market stability. Another commenter stated that EPA should lower the ethanol mandate to the blend wall and shift the reduced volumes to the advanced biofuel requirement.

Many commenters suggested that the SRE reallocation volumes would harm nonexempt refineries, with some commenters focusing on independent refineries that have to purchase RINs.

Response:

We do not find that it would be appropriate to exclude volumes that would be blended without the RFS program from the calculation. The commenter did not explain what purpose doing so would serve, and thus EPA is unable to fully evaluate this suggestion.

We respond to comments about impacts on refineries in RTC Section 9. The analysis there includes consideration of the SRE reallocation volumes, which we do not anticipate will adversely impact refineries. We note 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.[122] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs.

We respond to comments about the implied conventional volume in Preamble Section III and RTC Sections 5 and 6.

Comment:

Several commenters supported EPA's approach to having SRE reallocation volumes for both 2026 and 2027. A commenter suggested only 2026 would be "most appropriate" but supported spreading the volume over two years to "lessen the disruption." The commenter suggested spreading the volume over four years would also be appropriate.

Response:

We thank the commenters for their support. As described in Preamble Section IV, we are finalizing the SRE relocation volumes for both 2026 and 2027 to lessen the disruption to the market but still achieve the results of preserving the renewable fuel volume requirements for 2026 and 2027.

Comment:

A commenter suggested EPA evaluate the cellulosic biofuel category separately from the other categories under reallocation to address the different production and compliance limitations.

Response:

While the comment lacked the specificity necessary to fully evaluate the idea presented, we do note that we are not finalizing an SRE reallocation volume for cellulosic biofuel in light of the differing statutory language for this category of renewable fuel.

Comment:

Some commenters suggested alternatives to reallocation.

Response:

These alternatives are beyond the scope of this action.

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[122] 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 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.

7.3.3 Projection of 2026 and 2027 Exempted Gasoline and Diesel Volumes

Comment:

Many commenters supported EPA's use of a transparent, data-driven, three-year rolling average methodology to estimate prospective exemptions for 2026 and 2027 as an approach that would provide predictability and certainty to the market, support robust renewable fuel volumes, or maintain RFS program integrity. Some of the commenters noted that additional SRE petitions had been submitted after the supplemental proposal and requested that EPA update its projections in the final rule to account for decisions issued after the supplemental proposal.

Response:

We thank the commenters for their support. As described in Preamble Section IV, we have updated our projection of exempted volumes to account for SRE petition decisions issued in the November 2025 SRE Decisions Action.

Comment:

Several commenters opposed prospective SRE reallocation for 2026 and 2027. The commenters stated that, as a result of the decision in *Sinclair Wyoming Refining Co., LLC v. EPA,* EPA now lacks a reliable basis for predicting exemptions for 2025 and the Agency offers no new rationale for predicting exemptions. The commenters argued that because EPA does not know how many small refineries will apply for exemptions or whether such petitions will be granted for 2026 and 2027, the supplemental proposal was arbitrary and capricious.

Response:

We disagree with the commenters that EPA lacks a reliable basis for projecting future exemptions. On the contrary, EPA issued decisions on nearly 200 SRE petitions in the 2025 SRE Decisions Actions, spanning the 2016–2024 compliance years. In those actions, EPA clearly explained and articulated its basis and rationale for how the Agency will evaluate SRE petitions, including those for the 2026 and 2027 compliance years. Thus, EPA has a well-documented basis for projecting future exemptions.

Contrary to the commenters' assertion, EPA clearly explains its rationale for projecting future exemptions by using a three-year rolling average of exempted gasoline and diesel volumes in Preamble Section IV, stating that the use of a three-year average is intended "to average the effects of unique events or market circumstances that occurred in individual years […] and thus serves as a better predictor of the volume of gasoline and diesel that will ultimately be exempted[.]" Commenters' opposition to use of the three-year average methodology rings hollow, as they fail to provide any meaningful or substantive critique of the methodology, or a suggestion for how EPA could more accurately project future exempt volumes. Rather, commenters merely assert that because EPA cannot know the exact number of SRE petitions in 2026 and 2027 and how they will be decided, the Agency's projected exempt volumes must be arbitrary and capricious.

It is true that the actual exempted volumes for 2026 and 2027 may be higher or lower than the volumes projected by EPA in this final rule, as EPA does not currently know (and could not know) exactly how many SRE petitions will be submitted for 2026 and 2027 or how many will ultimately be granted or denied. However, the same is true for the projected volumes of gasoline and diesel used in the percentage standards equations, as well as many other projections used or developed by EPA to support this final rule. EPA is under no statutory obligation to retroactively correct its gasoline and diesel projections in the percentage standards equations after the compliance year is over, and the same is true for the projection of exemptions.

By the commenters' logic, EPA could only use a projection of exempt gasoline and diesel based on actual decisions issued for the year in question, thereby negating the entire purpose of the GE_i and DE_i, which is to *project* exempted volumes of gasoline and diesel for the year in question. Indeed, several of the commenters were among challengers to EPA's change to the GE_i and DE_i terms in litigation over the 2020–2022 RFS Rule. The D.C. Circuit upheld EPA's changes to the percentage standards equations, noting that "[t]he statute does not confine EPA to the Refiner Petitioners' preferred method of accounting for small-refinery exemptions, and EPA's choice to account for them both retrospectively and prospectively is not arbitrary or capricious."[123] Thus, there is nothing arbitrary or capricious about EPA's projection of exempted gasoline and diesel volumes for 2026 and 2027.

Comment:

Several commenters recommended that EPA consider reducing the assumed exempted volumes over time to decrease the volume of exempted fuel to only reflect the demonstrated hardship due to RFS compliance and to align with EPA's understanding in its August 2025 SRE decisions that "exemptions would become more targeted over time."

Response:

We disagree that we should reduce the projection of exempted volumes as suggested by the commenters. EPA's statement that "Congress's intent that exemptions would become more targeted over time" was in support of the interpretation that EPA has authority to find partial hardship in deciding SRE petitions.[124] This was evidenced by the fact that the initial statutory exemption applied to all small refineries through 2010, then the exemption was narrowed to those small refineries that DOE found would experience hardship through 2012, and then finally the exemption was narrowed to those small refineries that petition EPA for an exemption. While exemptions have indeed become more targeted since the inception of the RFS2 program, we are now operating under the narrowest set of statutory SRE provisions in which small refineries must petition for an exemption. We do not currently expect that exemptions will become more targeted in 2026 and 2027 compared to 2022–2024 (the years for which we based our projection of exempt gasoline and diesel in 2026 and 2027); rather, we believe that the three-year average methodology is the best estimate of prospective exemptions for 2026 and 2027.

[123] *Sinclair*, 101 F.4th at 891.
[124] August 2025 SRE Decisions Action Section III.H.

Comment:

One commenter urged EPA not to attempt to "true-up" discrepancies between projected and actual exempted volumes, but instead to limit the reallocation of historic SREs to this rulemaking and to use a consistent approach to the reallocation of prospective projected SRE volumes.

Response:

As described in Preamble Sections IV and V, we are only reallocating exempted volumes for the 2023–2025 compliance years because these are the years for which the exemptions granted had the ability to impact the RIN market, as 2023 and newer vintage RINs were valid for RFS compliance at the time the exemptions were granted. For 2026 and beyond, 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.

Comment:

Several commenters argued that reallocating a projection of future exempt volumes to other obligated parties is not authorized under the CAA.

Response:

EPA did not reopen the inclusion of a projection of future exempted gasoline and diesel volumes (GE_i and DE_i) in the percentage standard equations in this rulemaking. EPA's authority to reallocate exempted volumes was upheld by the D.C. Circuit in *Sinclair v. EPA*, 101 F.4th 871, 891 (2024). Thus, this issue has already been settled by the court and the commenters' arguments are beyond the scope of this rulemaking.

Comment:

A commenter suggested EPA was underestimating the exempted volumes, as the August 2025 SRE Decisions Action returned 1.1 billion 2023 vintage RINs, and 3.3. billion "live 2019-2023" RINs, but EPA only estimated 670 million and 730 million returned RINs.

Response:

We have updated our estimates of the 2023–2025 exempted RVOs to reflect the most up to date information, including additional SREs granted in the November 2025. As described in Preamble Section IV.A, RINs returned for 2019–2022 SREs were expired at the time the 2025 SRE Decisions Actions were made and thus could not be used for compliance with 2024 or later RFS obligations. Furthermore, we have updated our projection of the number of available carryover RINs for all years to account for all the RINs returned as part of the 2025 SRE Decisions Actions. We believe the number of carryover RINs provides a holistic view of how the 2025 SRE Decisions Actions are likely to impact compliance with the volume obligations in future years, as the number of available carryover RINs accounts for the impacts of these decisions as well as information submitted to EPA in compliance reports for the 2024 (and earlier) compliance years. See RIA Chapter 1.8.3 for these updated historical projections.

We note that in order to simplify implementation of the exemptions granted in the 2025 SRE Decisions Action, EPA returned *all* the RINs retired by a small refinery that received either a full (100%) or partial (50%) exemption for a particular compliance year. Refineries that received a partial exemption then re-retired sufficient RINs to satisfy their remaining 50% RVOs. The commenter may have misinterpreted these transactions in EPA's public data reports as the Agency returning more RINs than estimated in the Set 2 proposal.

7.3.4 Revised Proposed Percentage Standards for 2026 and 2027

Comment:

Several commenters argued that removing exempted volumes of gasoline and diesel from the denominator of the percentage standard equations wrongly assumes that each exempted gallon of fuel results in a corresponding reduction in the amount of renewable fuel introduced into the fuel supply (*i.e.*, renewable fuel is not blended into fuel produced by exempted small refineries) and results in overcompliance. One of the commenters argued that this approach was no longer valid based on EPA's proposal to reallocate exempted RVOs.

The commenters stated that if EPA reallocates exempted volumes of gasoline and diesel, it should also make a corresponding reduction in the renewable fuel volume requirement in the numerator of the percentage standard equations to account for the renewable fuel blended into the exempted gasoline and diesel, consistent with CAA section 211(o)(3)(C)(ii).

Response:

EPA has included a projection of exempted volumes of gasoline (GE_i) and diesel (DE_i) in the denominator of the percentage standard equation since the inception of both the RFS1 program (for gasoline)[125] and RFS2 program (for gasoline and diesel).[126] While EPA has revised how it makes those projections over the years, the GE_i and DE_i terms have nevertheless always been part of the percentage standards equations and EPA did not propose to change that in this action.[127] EPA's reallocation of exempted RVOs in this final rule is irrelevant to the inclusion of a projection of exempted volumes of gasoline and diesel in the denominator of the percentage standard and thus comments on this topic are beyond the scope of this action.

Regardless, commenters are incorrect that EPA assumes that exempt small refineries do not blend renewable fuel into their transportation fuel. We agree that most gasoline and diesel produced by exempted refineries will ultimately still be blended with RIN-generating renewable fuels. However, the purpose of including a projection of exempted volumes of gasoline and diesel in the percentage standard equations is to reallocate the obligation associated with those exempted volumes to other non-exempt obligated parties. This ensures that there is sufficient demand for renewable fuel by non-exempt obligated parties such that the renewable fuel volume requirements established by EPA will be achieved.

Commenters' argument that EPA should make a corresponding reduction in the volume requirements in the numerator of the percentage standard equations is either a misunderstanding of the RFS program or a misreading of the statute. Under the RFS program, renewable fuel blended into gasoline and diesel produced by exempt small refineries still generates a RIN that is valid for compliance by obligated parties. Were such blended renewable fuel *not* eligible for RIN generation, that it may be appropriate to reduce the volume requirement to account for such non-RIN generating renewable fuel. However, such is not the case under the RFS program and we are

[125] 72 FR 23900, 23993-94 (May 1, 2007).
[126] 75 FR 14670, 14867 (March 26, 2010).
[127] EPA did propose and is finalizing in this action minor editorial changes to the definitions of GE_i and DE_i, but those changes do not materially affect the meaning of the terms. EPA did not reopen the meaning of those terms.

declining to make such an adjustment in this final rule. Furthermore, we note that EPA addressed this very issue in the RFS2 rule, stating:

> CAA section 211(o)[3] requires that the small refinery adjustment also account for renewable fuels used during the prior year by small refineries that are exempt and do not participate in the RFS2 program. Accounting for this volume of renewable fuel would reduce the total volume of renewable fuel use required of others, and thus directionally would reduce the percentage standards. However, as we discussed in RFS1, the amount of renewable fuel that would qualify, *i.e.*, that was used by exempt small refineries and small refiners but not used as part of the RFS program, is expected to be very small. In fact, these volumes would not significantly change the resulting percentage standards. Whatever renewable fuels small refineries and small refiners blend will be reflected as RINs available in the market; thus there is no need for a separate accounting of their renewable fuel use in the equations used to determine the standards. We proposed and are finalizing this value as zero.[128]

Also as described elsewhere in this document, EPA takes the position that CAA section 211(o)(3)(C) no longer applies.

[128] 75 FR 14670, 14717 (March 26, 2010).

7.3.5 SRE Reallocation for Cellulosic Biofuel

Comment:

EPA received comments both against and in support of cellulosic biofuel SRE reallocation volumes for 2026 and 2027.

Some commenters suggested that EPA should not treat cellulosic biofuel differently from other fuel types when determining whether to reallocate 2023–2025 exempted RVOs and encouraged EPA to include SRE reallocation volumes for cellulosic biofuel to support to cellulosic biofuel industry. Some commenters suggested that EPA is required to include the 2023–2025 exempted cellulosic biofuel RVOs in the SRE reallocation volumes.

A commenter argued that EPA is required to include SRE reallocation volumes for cellulosic biofuel, noting that the condition in CAA section 211(o)(2)(iv) does not limit EPA in any way when setting cellulosic biofuel volumes for 2023 and beyond, and merely requires EPA to set the cellulosic volume requirement "without regard to whether the CWA will be triggered." The commenter also suggested that the SRE reallocation volumes are not contrary to EPA's proposed interpretation of CAA section 211(o)(2)(iv): EPA has proposed to determine the projected production and provisionally established the volume requirements at that level, but then independently adjusts the volumes upward to preserve the efficacy of the production-based volume requirements in light of the additional carryover RINs. Another commenter suggested that CAA section 211(o)(2)(iv) cannot be used to avoid EPA's duty to ensure the volume requirements are met, and that doing so would not be taking a "neutral aim at accuracy" as required by the D.C. Circuit.

A commenter suggested that if EPA decides not to reallocate SRE volume for cellulosic biofuel, it should not reduce the SRE reallocation volumes for total renewable fuel as there is ample additional conventional ethanol to backfill the shortfall. Another commenter suggested that EPA should not reduce the advanced biofuel SRE reallocation volume if EPA decides not to reallocate SRE volume for cellulosic biofuel.

A commenter suggested that a full cellulosic biofuel SRE reallocation volume would incentivize RNG growth and support regulatory and investment certainty.

A commenter suggested that the despite EPA suggesting the authority to establish SRE reallocation volumes is CAA section 211(o)(2)(B)(ii), a cellulosic biofuel SRE reallocation volume would be an appropriate remedy for addressing "improper waivers of the volume requirements" and that the SRE reallocation volumes are distinct from CAA section 211(o)(2)(B)(ii), and thus EPA is not bound by the language in CAA section 211(o)(2)(B)(iv). The commenter also suggested that EPA could only act with a "neutral aim at accuracy" if it included the carryover RINs. The commenter suggested that CAA section 211(o)(2)(iv) cannot be used to avoid EPA's duty to ensure the volume requirements are met.

Conversely, some commenters suggested that CAA section 211(o)(2)(B)(iv) requires EPA to set cellulosic biofuel standards based solely on projected production for the 2026 and 2027 compliance years. These commenters suggested that the proposed SRE reallocation volumes for cellulosic biofuel violated the requirements of CAA section 211(o)(2)(iv), which requires that EPA set the cellulosic biofuel volume based on the assumption that EPA will not need to waive the volumes using the CWA. The commenters pointed to the D.C. Circuit's opinion in *Sinclair v. EPA*, holding that the phrase "projected volume available" excludes carryover RINs. Commenters suggested a cellulosic biofuel SRE reallocation volume risks imposing unachievable obligations on obligated parties. These commenters suggested EPA should not require SRE reallocation volumes for cellulosic biofuel and instead make corresponding reductions in the advanced biofuel and total renewable fuel SRE reallocation volumes. The commenters also suggested that the SRE reallocation volumes will not actually be available for compliance with the SRE reallocation volumes due to insufficient cellulosic carryover RINs.

Response:

As described in Preamble Section IV, we are not establishing cellulosic biofuel SRE reallocation volumes.

In response to the commenter who suggested that CAA section 211(o)(2)(B)(iv) does not limit EPA's authority in setting the cellulosic biofuel volume, we disagree with the commenter's reading of the statute, as discussed in Preamble Section II and RTC Section 2. The statute is best read to require EPA to set cellulosic biofuel volumes under CAA section 211(o)(2)(B)(iv) such that we do not anticipate needing to waive the cellulosic biofuel standard in the future. Thus, we are again establishing the cellulosic biofuel volume at the "projected volume available."

As to the comments that it is possible to harmonize CAA section 211(o)(2)(B)(iv) by suggesting that the renewable fuel volumes (*i.e.*, the volumes that EPA anticipates will be produced in 2026 and 2027) must meet CAA section 211(o)(2)(B)(iv), and then EPA has authority to "independently adjust[] the volume upward to preserve the efficacy of the production-based volume requirement," we disagree. In this final rule, we find our authority to establish SRE reallocation volumes in CAA section 211(o)(2)(B)(ii), and thus CAA section 211(o)(2)(B)(iv) applies to all components of that requirement, including the SRE reallocation volumes. Because we are already setting the cellulosic biofuel renewable fuel volume requirement for 2026 and 2027 at the projected volume available in those years, and the projected volume available excludes carryover RINs, we are unable to establish a combined applicable volume that complies with CAA section 211(o)(2)(B)(iv). Therefore, we are not establishing cellulosic biofuel SRE reallocation volumes.

We do not rely on the language in CAA section 211(o)(2)(A) to establish the SRE reallocation volumes, and our action in this final rule is not contrary to that provision. Instead, we are establishing applicable volumes for cellulosic biofuel that are equivalent to the "projected volume available." In doing so, we have also taken a "neutral aim at accuracy" and have not been intentionally optimistic or pessimistic in our estimates of cellulosic biofuel.

While we recognize that requiring the use of some cellulosic carryover RINs has the potential to support the RNG industry, we find that we are constrained by the statute in establishing the cellulosic biofuel volumes under CAA section 211(o)(2)(B)(ii) and (iv).

We decline to make corresponding reductions in the advanced biofuel and total renewable fuel SRE reallocation volumes for the reasons described in Preamble Section IV.

8. Partial Waiver of the 2025 Cellulosic Biofuel Volume Requirement

8.1 Waiver Authorities

8.1.1 General Comments on the Cellulosic Waiver Authority

Comment:

Some commenters supported EPA's proposed use of the cellulosic waiver authority for 2025.

Other commenters opposed EPA's proposed use of the cellulosic waiver authority for 2025, arguing that the statutory criteria for implementing the cellulosic waiver authority were not met given sufficient RNG production. The commenter suggested that the use of "production" in CAA section 211(o)(7)(D)(i) requires EPA to assess production without consideration of consumption given the RFS's role as a "market forcing policy." The commenter suggested that when evaluating the "cellulosic biofuel production" under CAA section 211(o)(7)(D) to determine if a waiver has been triggered, EPA should use the growth rate methodology previously used, and not the current assessment which includes consumption.

Response:

Consistent with our approach in waiving the 2024 cellulosic biofuel standard, we assess the "cellulosic biofuel production" through an evaluation of the number of cellulosic RINs available.[129] This is because an estimate of RNG would overestimate the production of cellulosic biofuel, which, to meet the statutory definition and qualify under the RFS program, requires that the RNG be used as transportation fuel.

As described in Preamble Section III.B, at this time, we are unable to rely on RIN generation alone to assess the number of cellulosic RINs available. RIN generation alone would overestimate cellulosic biofuel production because RIN generation now occurs prior to confirmation that the renewable CNG/LNG is used as transportation fuel as required by the statute and RFS regulations. Commenters suggested EPA should decline to waive the 2025 cellulosic biofuel volume requirement given available RNG, without any consideration of whether such RNG is used as transportation fuel. Doing so would not be consistent with EPA's past practice and would improperly overestimate the available cellulosic biofuel.[130]

We recognize that the RNG production capacity and projected total quantity of RNG produced in 2025 are both higher than the projected number of 2025 cellulosic RINs generated for RNG. However, CAA section 211(o)(7)(D) requires that EPA assess cellulosic biofuel production, not RNG production capacity nor the projected total quantity of RNG produced. It would not be

[129] 90 FR 29751 (July 7, 2025).
[130] 80 FR 77420, 77428 (December 14, 2015); 87 FR 39600, 39602–03 (July 1, 2022). This is also consistent with how EPA assesses cellulosic biofuel prospectively—we do not set the standards at the volume of RNG that is likely to be produced, but rather at the volume of RNG that is likely to be used as transportation fuel, thus ensuring it is qualifying renewable fuel.

appropriate to assess the cellulosic biofuel production volume using the production capacity for RNG or the projected total quantity of RNG produced in 2025.

When using the cellulosic waiver authority, CAA section 211(o)(7)(D)(i) directs EPA to "reduce the applicable volume of cellulosic biofuel… to the projected volume available during that calendar year." There are many reasons that the projected volume of RNG, let alone available qualifying cellulosic biofuel, would fall short of production capacity, including facility downtime for maintenance and repairs, unexpected production stoppages, lower than expected production yields, and poor weather conditions. The RNG production capacity is therefore not an appropriate means for projecting the volume of RNG available during the calendar year.

Further, not all RNG qualifies as cellulosic biofuel. To qualify as cellulosic biofuel, RNG must be produced from qualifying feedstocks and be used as transportation fuel.[131] Total RNG production in the U.S. includes both RNG that is produced from non-cellulosic feedstocks (*e.g.*, food waste) and RNG that is not used as transportation fuel (*e.g.*, for electricity or process heat). RNG produced from non-cellulosic feedstocks or not used as transportation fuel does not qualify as cellulosic biofuel under the RFS program. It would therefore be inconsistent with the CAA to determine the "projected volume available" for cellulosic biofuel based on total RNG production, as not all RNG qualifies as cellulosic biofuel. The D.C. Circuit has upheld this approach in determining the "projected volume available" under the cellulosic waiver authority, concluding that in "taking neutral aim at accuracy," EPA must consider those factors likely to influence the availability of qualifying renewable fuel.[132]

Comment:

A commenter opposed the implementation of the cellulosic waiver authority because there would be negative impacts of waiving the cellulosic biofuel requirement on market stability and planned investments, including reducing demand for cellulosic RINs and decreasing cellulosic RIN prices, creating volatility in the market, and reducing potential revenues, particularly for new and future projects.

A few commenters argued that EPA has an obligation to enforce the volume requirements it sets to ensure that obligated parties take their obligations seriously all year and make the required investments to grow the program and meet the standards.

Several commenters noted EPA's statements in the Set 1 Rule suggesting that "[r]evising standards has the potential to decrease market certainty and create unnecessary market disruption." Relatedly, commenters suggested that waiving volumes introduces market uncertainty and harms producers' investments. Some commenters noted that obligated parties anticipating a waiver could incentivize a "wait-and-see" approach to purchasing RINs in the hope of a waiver, which would lead to pricing instability and threaten continued investment in the market for cellulosic biofuel.

[131] CAA section 211(o)(1)(J) defining renewable fuel, (o)(1)(E) defining cellulosic biofuel.
[132] *Growth Energy*, 5 F.4th at 14-15.

Response:

While we recognize the potential impacts on the cellulosic biofuel market and cellulosic RIN prices, as well as EPA's delay in issuance of the partial waiver, the use of the cellulosic waiver authority is mandatory and thus we lack the discretion to consider the factors suggested by the commenters in implementing the cellulosic waiver authority to waive the 2025 cellulosic biofuel requirement. We note that in the Set 1 Rule, EPA highlighted the potential availability of the waiver authorities, including the cellulosic waiver authority.[133] Additionally, the mandatory and prescriptive nature of the cellulosic waiver authority should provide stakeholders with certainty about the circumstances under which EPA would be required to implement a waiver.

As to commenters' suggestion that obligated parties might postpone cellulosic RIN purchases to evoke a partial waiver of the cellulosic biofuel standard, we note that we have articulated a similar concern in denying past requests for a waiver of the cellulosic biofuel standard.[134] However, in contrast to the circumstances there, without this action, obligated parties would lack the certainty of CWCs as an alternative compliance mechanism, and thus delaying cellulosic RIN purchases would likely be a higher-risk option for obligated parties, were EPA to not ultimately reduce the cellulosic biofuel volume requirement using the cellulosic waiver authority. Further, the cellulosic biofuel industry has developed significantly in recent years. The relatively mature status of the RNG industry, along with the relatively large number of potential buyers for RNG and other cellulosic biofuels, reduces the risk that obligated parties would be able to directly influence cellulosic biofuel production by delaying RIN purchases. Therefore, we believe the likelihood of such actions is diminished.

Comment:

A commenter supported EPA's proposed reduction in the 2025 cellulosic biofuel standard using the cellulosic waiver authority, but suggested that when EPA reduces the volume, it must also account for carryforward deficits and a "depleted RIN bank." The commenter suggested that the shortfall is a direct result of "aspirational" cellulosic volumes for 2023, 2024, and 2025. The commenter also suggested that it was "unreasonable and contrary to D.C. Circuit precedent to expect obligated parties to purchase CWCs to satisfy the carryover deficits that directly resulted from EPA setting unachievable cellulosic biofuel mandates."

The commenter explained that EPA's failure to waive the 2023 cellulosic standard, in combination with setting the 2024 cellulosic standard at the available number of cellulosic biofuel RINs without accounting for deficits results in obligated parties needing to purchase cellulosic waiver credits and advanced biofuel RINs. The commenter argues that this is contrary

[133] 88 FR 44479 (July 12, 2023) ("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 waiver authorities should circumstances so warrant."). *See also* "RFS Program - Standards for 2023–2025 and Other Changes: Response to Comments," EPA-420-R-23-014, June 2023 ("Set 1 Rule RTC"), Section 2.2.

[134] EPA, "Denial of AFPM Petition for Waiver of 2016 Cellulosic Biofuel Standard," January 17, 2017.

to the D.C. Circuit's statements in *API v. EPA* where the court characterized the purchase of CWCs as a "penalty" for obligated parties.

Response:

EPA acknowledges that obligated parties that carried forward a deficit into 2025 will need to retire RINs to comply with their 2025 cellulosic biofuel obligation and their deficit carried forward from 2024, and that certain obligated parties may need to purchase CWCs to comply if sufficient cellulosic RINs are not available. However, obligated parties that did not carry forward a cellulosic biofuel deficit from 2024 can also choose to carry forward a cellulosic biofuel deficit from 2025 to 2026, as obligated parties have done for every year since 2013.[135] Additionally, although the purchase of CWCs is a cost obligated parties may choose to incur, it is by no means a requirement, and it is expressly contemplated by the statute as a compliance flexibility when EPA exercises the cellulosic waiver authority.

As described by EPA in response to the commenter in other contexts, we do not believe that the use of CWCs would amount to an unjust penalty.[136] The costs are similar whether compliance is achieved through purchase of RINs or CWCs and, therefore, compliance through use of CWCs is not more burdensome for obligated parties than would be the case if parties chose to comply with cellulosic RINs.[137]

The cellulosic waiver authority is prescriptive as to the volume at which EPA is to reduce the cellulosic biofuel standard. The D.C. Circuit has indicated that the "projected volume available" does not include carryover RINs.[138] EPA has historically also excluded deficits from the prior year in determining the projected volume available, as those deficit volumes, while required on an individual basis under the CAA and EPA's regulations, represent obligations from the prior year, and do not represent renewable fuel available.[139] We are thus maintaining our exclusion of deficits when determining the projected volume of cellulosic biofuel available.

Finally, we note that our assessment of cellulosic RIN deficits and carryover RINs going into 2025 indicates that the absolute number of cellulosic carryover RINs (72 million RINs) exceeds the cellulosic RIN deficits carried forward from 2024 into 2025 (55 million RINs). Thus, the 2025 cellulosic biofuel standard, as waived in this action, and the 2024 cellulosic RIN deficits carried forward into 2025 can be met through the use of 2025 cellulosic RINs and 2024 cellulosic carryover RINs, such that CWCs will not need to be purchased by obligated parties to achieve compliance in aggregate.

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[135] "RFS Compliance Data as of February 20, 2026," available in the docket for this action.
[136] EPA, "Denial of AFPM Petition for a Waiver of the 2016 Cellulosic Biofuel Standard," January 17, 2017.
[137] See RIA Table 1.7.2-4, demonstrating the relationship between cellulosic RINs, advanced RINs, and the CWC prices.
[138] *Sinclair*, 101 F.4th at 886. ("[W]e hold that the cellulosic waiver provision unambiguously excludes carryover cellulosic RINs from the 'projected volume available.'")
[139] "RFS Program – Partial Waiver of 2024 Cellulosic Biofuel Volume Requirement: Response to Comments," EPA-420-R-25-008, June 2025, Section 2.2.

Comment:

A commenter suggested that, as an alternative to reducing the 2025 cellulosic biofuel standard under the cellulosic waiver authority, EPA should instead reconsider the determination in the Set 1 Rule that it was not possible to both reduce the cellulosic volume under the cellulosic waiver authority and set the cellulosic biofuel standard under CAA section 211(o)(2)(B) and again set the 2025 cellulosic biofuel volume requirement at 1.38 billion RINs with CWCs available as a compliance flexibility. The commenter suggested this would be a better interpretation of the statute, and that it would not create the disincentives of the partial waiver for 2025.

Response:

We decline to adopt the commenter's suggestion. Our interpretation of CAA sections 211(o)(2)(B)(iv) and (o)(7)(D) does not permit the use of the cellulosic waiver authority at the same time the volume requirement is set under CAA section 211(o)(2)(B)(ii), as described in Preamble Section II and RTC Section 2. It is also unclear how doing so would impact the disincentives given the timing of this action and that the 2025 compliance year has passed.

Comment:

Commenters supported EPA's proposal to maintain the 2025 advanced biofuel and total renewable fuel standards.

Response:

EPA appreciates the commenters' support. We are not finalizing any further reductions to the 2025 advanced biofuel and total renewable fuel standards.

8.1.2 Availability of Cellulosic Waiver Authority

Comment:

Commenters stated that even if the cellulosic waiver authority is still available, the language of CAA section 211(o)(7)(D) precludes it from being implemented to retroactively waive cellulosic biofuel volumes or make CWCs available after November 30, 2024 (*i.e.*, the statutory language requires that EPA shall reduce the established volumes prior to a compliance year to "the projected volume available" for that year and it must do so "not later than November 30 of the preceding calendar year"). Commenters suggested that the plain language of the statue indicates Congressional intent that the waiver be prospective and forward-looking. A commenter disagreed with EPA's interpretation of "projected," contending that it distorted the meaning of the term. The commenter also noted the statute's use of the term "preceding" and contended that this language also indicates that the cellulosic waiver authority should be used prospectively.

Another commenter suggested that this interpretation is appropriate because EPA's regulations are similarly written in prospective terms; for example, the price of CWCs is to be based on data available "as of September 30 of the year preceding the compliance period" and the inflation index "for June of the year preceding the compliance period." The commenter believes this language is because CWCs are intended to serve as a price stabilizer during the compliance year to avoid potential substantial increases in RIN prices while cellulosic biofuel production ramps up. The commenter asserted this can't occur if EPA makes a determination that CWCs can be available after the end of the compliance year. The commenter also pointed to the language in CAA section 211(o)(7)(D)(iii) directing EPA to issue regulations to ensure that the CWCs do not undermine the goals of the statute. A commenter suggested EPA was improperly attempting to treat the cellulosic waiver authority deadline like other deadlines within CAA section 211(o) and argued that the cellulosic waiver authority does not confer authority on EPA to use it retroactively. The commenter pointed to the D.C. Circuit's decision in a non-RFS CAA case to argue that EPA lacks the authority to implement rules retroactively.

A commenter opposed EPA's interpretation of the cellulosic waiver authority, arguing that the statute refers to the "projected volume of cellulosic biofuel production," and that production is defined as "the amount of goods manufactured or grown by a company or country.[140]" The commenter argued that EPA cannot look to RIN generation to determine the projected production, which is to be based on estimates provided in the prior year, and done not later than November 30 of the preceding year. The commenter suggested that the D.C. Circuit's decision in *ACE* indicates that EPA cannot redefine clear statutory language to expand its waiver authority, noting that the meaning of "production" is even more clear than the meaning of "inadequate domestic supply." The commenter suggests that this means the cellulosic waiver authority is not available to reduce the cellulosic biofuel volume. The commenter also suggests that the deficit carry forward provision is the mechanism available to address shortfalls in cellulosic RIN generation, not the cellulosic waiver authority. The commenter noted the difference in the procedural requirements associated with use cellulosic waiver authority and general waiver authority (*i.e.*, EPA must consult with USDA and DOE and provide an opportunity for notice and

[140] Definition of production, Collins dictionary.

public comment prior to waiving volumes under the general waiver authority) and suggested that late waivers under the cellulosic waiver authority would circumvent the general waiver authority requirements. The commenter noted that EPA did not claim ambiguity in the statute, or a gap to fill.

A commenter argued that EPA's reliance on case law from the D.C. Circuit affirming EPA's authority to establish standards retroactively is not applicable here, where EPA is instead retroactively waiving volume requirements. The commenter argued that a retroactive waiver impairs the statutory goals of increasing renewable fuel use.

Response:

As described in Preamble Section IV.A, the best reading of the statute is that the cellulosic waiver authority remains available to EPA to waive the volume requirements established under CAA section 211(o)(2)(B)(ii) and after the EIA estimates are no longer provided under CAA section 211(o)(3)(A).

In response to comments about whether the statute contains ambiguity or "gaps to fill," we maintain that the best reading of the statute is that the CAA requires EPA to reduce the cellulosic biofuel volume requirement when projected production is less than the applicable volume. This interpretation is clear on the face of the statute.

In response to comments regarding availability of the cellulosic waiver authority after the November 30, 2024, deadline articulated in the statute for the 2025 cellulosic biofuel volume requirement, we refer to Preamble Section IV.A. We also respond to comments about the statutory use of the terms "projected" and "preceding" in Preamble Section IV.A.

We note first that use of the cellulosic waiver authority is mandatory, and thus we are satisfying our statutory obligation to reduce the cellulosic biofuel volume requirement in these circumstances. We acknowledge as well that the statutory text of the cellulosic waiver authority does contemplate a prospective waiver of the cellulosic biofuel volume requirement. Because this action is prospective of the 2025 compliance deadline (September 1, 2026), it is also prospective, as contemplated by the D.C. Circuit in *Monroe v. EPA*.[141] This is not, however, different from other statutory authorities in the RFS program, which also contemplate prospective actions, but nevertheless, we have exercised retroactively, and which the D.C. Circuit has permitted upon review.[142]

The direction provided by the cellulosic waiver authority to reduce the cellulosic biofuel volume requirement to the "projected volume available" reflects congressional intent for this RFS category as modified by use of the cellulosic waiver authority. Thus, the resulting volume will require the use of the available cellulosic RINs, without requiring obligated parties to carry forward deficits or utilize carryover RINs. Because 2025 has already passed, this rulemaking has no ability to affect actual production, import, or use of cellulosic biofuel in 2025. While we lack discretion to adjust the 2025 cellulosic biofuel volume requirement to anything other than the

[141] 750 F.3d at 920.
[142] See, *e.g.*, *CBD*, 141 F.4th at 184.

“projected volume available,” the notice and delayed compliance deadline provide mitigation of burdens for obligated parties.

As discussed in Preamble Section IV.A, we read the statutory provisions in harmony to allow for the continued availability of the cellulosic waiver authority.

As discussed Preamble Section II.B, though CAA section 211(o)(7)(D)(i) requires EPA to make a determination “based on the estimate provided [by EIA],” the D.C. Circuit, in evaluating this provision held that the Act “[p]lainly . . . [does not] contemplate slavish adherence by EPA to the EIA estimate,” and had Congress so intended “it could have skipped the EPA ‘determination’ altogether.” Thus, although EIA is no longer required to provide the estimate to EPA under CAA section 211(o)(3)(B)(i), EPA retains the ability to make a determination of a shortfall in projected cellulosic biofuel production without the use of the EIA estimate.

It is entirely reasonable and appropriate for EPA to look not only to the production of RNG in the market, but the production of RNG *and* whether that RNG is able to be used as transportation fuel as required by the CAA to qualify as renewable fuel under the RFS program. As explained previously, both terms can have meaning—the “projected volume available” could exclude cellulosic RINs that are retired because the fuel is exported, and thus not available. Such cellulosic biofuel would be “produced” in the applicable year but is not “available” for obligated parties to use for compliance. Thus, production of cellulosic biofuel could include cellulosic biofuel that could later be exported, and the “projected volume available” could exclude that cellulosic biofuel that is exported, because it is not available. We recognize that the D.C. Circuit used its analysis of CAA section 211(o)(7)(A)(ii) in *ACE* to inform its assessment the appropriateness of including carryover RINs in the “projected volume available” in CAA section 211(o)(7)(D)(i) in *Sinclair*.[143] However, this does is not the same as equating “inadequate domestic supply” to either “projected production of cellulosic biofuel” or “projected volume available.” Our assessment of the “projected production of cellulosic biofuel” evaluates whether RNG that is not used as transportation fuel is properly considered “cellulosic biofuel” and we find that it is not. Thus, the meaning of “inadequate domestic supply” in the context of CAA section 211(o)(7)(A)(ii) does not bear on the meaning of “projected production of cellulosic biofuel” in CAA section 211(o)(7)(D)(i).

We also disagree with a commenter’s suggestion that CAA section 211(o)(2)(B)(iv) cannot be harmonized with use of the cellulosic waiver authority under CAA section 211(o)(7)(D) for the applicable volumes established under EPA’s “set authority.” Given that, per the statute, EPA is to set the applicable volumes “14 months before they will apply,” it is entirely possible that EPA could set standards based on a projection of cellulosic biofuel that, at the time the standard is established, EPA understands would not need to be waived, but for which future circumstances indicate that a waiver is required.

Regarding comments about the effect of EPA’s decision to not waive the 2023 cellulosic biofuel volume requirement, in evaluating the request from AFPM to do so, EPA did not address whether the conditions for use of the cellulosic waiver authority to waive the cellulosic biofuel volume requirement were met, but instead stated that “[t]he statute does not specify that it authorizes

[143] *Sinclair*, 101 F.4th at 884.

petitions to waive cellulosic biofuel volumes under CAA section 211(o)(7)(D). Accordingly, we do not consider AFPM's request to waive volumes under CAA section 211(o)(7)(D) to be properly before the Agency. Accordingly, to the extent the AFPM Petition raises issues relating solely to CAA section 211(o)(7)(D), we do not address those issues in this document."[144] Therefore, we disagree with the commenters' assertion that EPA acknowledged that the statute does not allow for retroactive waivers, as EPA made no such assertion in the AFPM 2023 Denial.

While the RFS program does seek to increase the volume of renewable fuel, it also states in clear terms that EPA must reduce the cellulosic biofuel volume requirement if projected production is less than the standard. This is consistent with the D.C. Circuit's findings that the RFS program does not incentivize growth "at all costs."[145]

We recognize that retroactive waivers impair market stability. However, CAA section 211(o)(7)(D) requires that EPA reduce the cellulosic biofuel requirement when the statutory conditions are met. Thus, we are unable to consider such effects of the action.

Comment:

A commenter suggested that there are alternatives to EPA's retroactive waiver. The commenter suggested the 2025 cellulosic biofuel standard could be met through: (1) obligated parties carrying forward cellulosic RIN deficits; (2) obligated parties relying on cellulosic carryover RINs; and (3) EPA could consider whether to issue a waiver under the general waiver authority.

Response:

We respond to each suggestion in turn. First, while obligated parties could carry forward deficits equivalent to the shortfall, doing so may result in noncompliance by some obligated parties unable to acquire sufficient cellulosic RINs, as obligated parties that carried forward a cellulosic RIN deficit from 2024 are unable to carry forward a cellulosic RIN deficit from 2025.[146] We noted such a potential outcome in our proposal to waive the 2024 cellulosic biofuel volume requirement.[147] Additionally, the cellulosic waiver authority is mandatory, such that EPA is required to reduce the volumes when the statutory criteria are met. Second, as described within this section there are insufficient cellulosic carryover RINs to make up for the shortfall in cellulosic biofuel for 2025. While a combination of carryover RINs and carryforward deficits may result in compliance in aggregate, we again note the mandatory nature of the cellulosic wavier authority. Finally, we have in the past considered the use of the general waiver authority to waive the cellulosic biofuel requirement. Nevertheless, we find it is more appropriate to use the cellulosic waiver authority for three reasons:(1) it is specific to cellulosic biofuel; (2) its use is mandatory; and (3) its use triggers the availability of CWCs, which are an important compliance flexibility for obligated parties.

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[144] EPA, "Denial of AFPM Petition for Partial Waiver of 2023 Cellulosic Biofuel Standard," March 2024 ("AFPM 2023 Denial").
[145] *Alon v. EPA*, 936 F.3d 628, 666-67 (D.C. Cir. 2019) (citing *ACE* at 714).
[146] CAA section 211(o)(5)(d); 40 CFR 80.1427(b).
[147] 89 FR 100442 (December 12, 2024).

Comment:

A commenter argued that EPA must make clear that once it uses the cellulosic waiver authority and CWCs are made available, it is no longer required or able to use the cellulosic waiver authority to reduce the volume requirements again. Commenters stated that the statute does not allow for multiple reductions.

Response:

Because we are using the cellulosic waiver authority to reduce the cellulosic biofuel volume for the first time for 2025, we need not opine on its availability in the circumstances the commenter suggests.

Comment:

A commenter suggested that EPA could have met the statutory deadline of November 30, 2024.

Response:

We recognize that the statute contemplates waiving the 2025 cellulosic biofuel volumes prior to November 30, 2024. For the reasons discussed in this section, we continue to be able to waive the cellulosic biofuel volume requirement using the cellulosic waiver authority even after this date.

8.2 Assessment of Cellulosic RIN Availability for 2025 Compliance and Proposed Volume Requirements

Comment:

Some commenters suggested that the proposed waiver of the 2025 cellulosic biofuel volume was premature and that EPA lacked sufficient data to justify the reduction, and they urged EPA to reconsider these actions or, if moving forward with a partial waiver, to base its determination on the latest RIN generation data available. A different commenter recommended that EPA bifurcate the 2025 cellulosic waiver decisions from the RFS Set 2 Rule to allow additional time to gather more accurate data.

Response:

EPA determined the final 2025 cellulosic biofuel volume requirement using the most current data available for this analysis, including RIN generation[148] and retirement[149] information compiled during development of this final rule. Because this determination relies on the latest RIN data, we believe that bifurcating the rule is unnecessary.

Comment:

Several commenters asserted that there was more than enough RNG production and that the use of "production" in CAA section 211(o)(7)(D)(i) requires EPA to assess production without considering consumption given the RFS's role as a "market forcing policy"; they disputed EPA's claim that shortfalls of RINs in 2023 and 2024 established a demand limitation requiring a waiver, noting EPA's acknowledgment that "projected RNG production is expected to exceed the projected consumption of RNG-derived CNG/LNG," and argued that EPA disregarded circumstances in 2023 and 2024 that may have reduced RIN generation despite ample RNG production capacity

Response:

Consistent with our approach in waiving the 2024 cellulosic biofuel standard, we assess the "cellulosic biofuel production" through an evaluation of the number of cellulosic RINs available. This is because an estimate of RNG would overestimate the production of cellulosic biofuel, which, to meet the statutory definition and qualify under the RFS program, requires that the RNG be used as transportation fuel.

As described in Preamble Section III.B, at this time, we are unable to rely on RIN generation alone to assess the number of cellulosic RINs available. RIN generation alone would overestimate cellulosic biofuel production because RIN generation now occurs prior to confirmation that the renewable CNG/LNG is used as transportation fuel as required by the

[148] 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.
[149] 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.

statute and RFS regulations. Commenters suggested EPA should decline to waive the 2025 cellulosic biofuel volume requirement given available RNG, without any consideration of whether such RNG is used as transportation fuel. Doing so would not be consistent with EPA's past practice and would improperly overestimate the available cellulosic biofuel.[150]

We recognize that the RNG production capacity and projected total quantity of RNG produced in 2025 are both higher than the projected number of 2025 cellulosic RINs generated for RNG. However, CAA section 211(o)(7)(D)(i) requires that EPA assess "cellulosic biofuel production," not RNG production capacity nor the projected total quantity of RNG produced. It would not be appropriate to assess the cellulosic biofuel production volume using the production capacity for RNG or the projected total quantity of RNG produced in 2025.

When using the cellulosic waiver authority, CAA section 211(o)(7)(D)(i) directs EPA to "reduce the applicable volume of cellulosic biofuel… to the projected volume available during that calendar year." There are many reasons that the projected volume of RNG would fall short of production capacity, including facility downtime for maintenance and repairs, unexpected production stoppages, lower than expected production yields, and poor weather conditions. The RNG production capacity is therefore not an appropriate means for projecting the volume of RNG available during the calendar year.

Further, not all RNG qualifies as cellulosic biofuel. To qualify as cellulosic biofuel, RNG must be produced from qualifying feedstocks and be used as transportation fuel. Total RNG production in the U.S. includes both RNG that is produced from non-cellulosic feedstocks (*e.g.*, food waste) and RNG that is not used as transportation fuel (*e.g.*, for electricity or process heat). RNG produced from non-cellulosic feedstocks or not used as transportation fuel does not qualify as cellulosic biofuel under the RFS program. It would therefore be inconsistent with the CAA to determine the "projected volume available" for cellulosic biofuel based on total RNG production, as not all RNG qualifies as cellulosic biofuel.

Comment:

Some commenters expressed concern about the potential for carryover RINs impacting the calculations of RIN shortfalls. A commenter argued that EPA's change in approach to handling cellulosic biofuel volume requirements necessitated reconsideration of EPA's decision not to consider carryover RINs in assessing available volumes of cellulosic biofuel when making reductions under the cellulosic waiver authority. While acknowledging that the D.C. Circuit had upheld EPA's refusal to consider carryover RINs in the past, the commenter noted that EPA was now clearly setting volumes based on its determination of how many RINs could be generated. As such, EPA was no longer looking merely at the supply of RNG, but at the supply of RINs that could be used to comply with volume requirements, of which carryover RINs are a key component. The commenters stated that with carryover 2022 D3 RINs, there were more than enough D3 RINs available to meet the 2023 volume requirements, which should not require a

[150] See 80 FR 77420, 77428 (December 14, 2015); 87 FR 39600, 39602-03 (July 1, 2022). This is also consistent with how EPA assesses cellulosic biofuel prospectively—we do not set the standards at the volume of RNG that is likely to be produced, but rather at the volume of RNG that is likely to be used as transportation fuel, thus ensuring it is qualifying renewable fuel.

waiver or reduction. They argued it was inconsistent to say a waiver was required because of insufficient RINs when there may be sufficient RINs when considering carryover RINs.

Response:

We disagree with the commenter's suggestion that EPA is taking a "new approach" to handling the cellulosic biofuel volume requirements by considering how many cellulosic RINs could be generated, and that our methodology for projecting cellulosic biofuel volume requirements has any impact on determining the "projected volume available" under CAA section 211(o)(7)(D)(i). EPA has always considered only qualifying cellulosic biofuel in projecting the cellulosic biofuel volume requirement. Thus, EPA has consistently and properly considered cellulosic RIN generation to determine the cellulosic biofuel volume requirement. This was true in the pre-Set years (*i.e.*, 2022 and earlier), when EPA was reducing cellulosic biofuel volumes through the cellulosic waiver authority,[151] and in establishing the 2023–2025 cellulosic biofuel volume requirements in the Set 1 Rule.[152] EPA has consistently interpreted the statutory phrase "projected volume available" to mean "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," and thus, does not include carryover RINs.[153] The D.C. Circuit in *Sinclair* indicated that "the statute clearly does not mandate the inclusion of carryover cellulosic RINs in calculating the 'projected volume available,'" and continued to note that the "projected volume available" is a "subset of the projected volume of production."[154]

As to commenter's suggestion that it is inconsistent to say a waiver was required when there are sufficient cellulosic RINs available when including carryover RINs, such a circumstance is not present for 2025, and thus we need not address such a situation. We estimate qualifying cellulosic biofuel production to be 1.21 billion RINs and available 2024 carryover RINs to be 72 million RINs.[155] These volumes, combined, are insufficient to comply with the original 2025 volume requirement of 1.38 billion RINs.

Comment:

Multiple commenters raised concerns about the impact of SREs on the cellulosic biofuel volume requirements. A commenter argued that if EPA granted any SREs, this would reduce the actual volume obligations, and thus EPA's failure to account for any exemptions would not "ensure" the volume requirements. They recommended that, at a minimum, EPA must justify continuing to use an assumption of no exemptions in setting any revised standard for 2025.

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[151] See, *e.g.*, "RFS Program: Standards for 2018 and Biomass-Based Diesel Volume for 2019 – Response to Comments," 420-R-17-007, December 2017, at 47 (describing our decision not to include volumes associated with biofuel for which a pathway has not yet been approved in cellulosic biofuel projections; given that biofuels cannot generate RINs without a valid pathway, this evidences EPA's longstanding position to consider RIN generation in its analysis).
[152] See Set 1 Rule RTC at 32.
[153] *Sinclair*, 101 F.4th at 883.
[154] Id.
[155] The 72 million cellulosic carryover RINs excludes the 55 million cellulosic RIN deficit carried forward by obligated parties from 2024 that will need to be satisfied in 2025.

Response:

In 2022, EPA established a mechanism to project SREs when determining the percentage standards implementing the RFS volume requirements.[156] That mechanism was upheld by the D.C. Circuit in *Sinclair*.[157] Thus, the percentage standard equations appropriately include terms that represent exempted volumes of gasoline and diesel as a result of projected SREs. At this time, we anticipate granting a number of SREs for the 2025 compliance year. Thus, we have considered updating the GE_i and DE_i terms in our calculation of the revised 2025 cellulosic biofuel percentage standard.

As described in Preamble Section VI.D, using a 2025 cellulosic biofuel volume requirement of 1.21 billion RINs and the same projections of the other variables from the Set 1 Rule results in a revised 2025 cellulosic biofuel percentage standard of 0.71%.[158]

However, we also evaluated what the impact on the revised 2025 cellulosic biofuel percentage standard would be if we not only updated the projection of exempted gasoline and diesel volumes in 2025 (as requested by the commenter), but also updated all other projections for 2025.[159] This includes updating the projections of gasoline and diesel, and the renewable fuels contained in those projections. This alternate calculation shows that the revised 2025 cellulosic biofuel percentage standard would still be 0.71%. In short, the increase in 2025 exempted gasoline and diesel volumes (approximately 7.6 billion gallons, as projected in Preamble Section IV.C) is essentially offset by the increase in 2025 gasoline and diesel volumes in 2025 (approximately 8.0 billion gallons), such that the revised 2025 cellulosic biofuel percentage standard does not change.

We maintain that it is still most appropriate to use the same projections of *all* variables from the Set 1 Rule to calculate the revised 2025 cellulosic biofuel percentage standard, including the projected zero gallons of exempted gasoline and diesel, as this results in all four 2025 percentage standards being calculated on the same bases.

Were we to adjust the other three percentage standards to include updated projections of exempted gasoline and diesel volumes, then we would be reallocating a portion of the projected 2025 exempted RVOs twice for those categories. As discussed in Preamble Section IV, we are already reallocating a portion of the projected 2025 BBD, advanced biofuel, and total renewable fuel exempted RVOs as SRE reallocation volumes in 2027. Thus, it would not be appropriate to also recalculate the 2025 percentage standards for these three categories to include a non-zero projection of exempted volumes, as it would essentially require obligated parties to comply with these reallocated exempted RVOs twice. This further supports our decision to use the projections from the Set 1 Rule to calculate the revised 2025 cellulosic biofuel percentage standard.

[156] 87 FR 39600, 39632-33 (July 1, 2022).
[157] *Sinclair*, 101 F.4th at 892.
[158] "Calculation of Final 2025 Cellulosic Biofuel Percentage Standard," available in the docket for this action.
[159] "Alternate Calculation of Final 2025 Cellulosic Biofuel Percentage Standard," available in the docket for this action.

Furthermore, as described above, regardless of whether we use the same projections as the Set 1 Rule or revise our projections to include updated data (including a non-zero projection of 2025 exempted volumes), the revised 2025 cellulosic biofuel volume requirement would still be 0.71%.

Comment:

A commenter suggested that if EPA misinterpreted the statute in declining to use the cellulosic waiver authority when it set the 2025 volume requirement, it could reconsider that interpretation and, while retaining the 1.38-billion-gallon requirement, issue CWCs for 2025. They suggested EPA could use the same approach for 2026 and 2027 but must set the volume requirements based on projected production. The commenter argued that if EPA sets the volumes at consumption, then EPA must confirm that it cannot use the cellulosic waiver authority in the future to reduce the volume requirements because the trigger for a cellulosic waiver would not be met.

Response:

As described in Preamble Section II and RTC Section 2, the best reading of the statute precludes EPA from using the cellulosic waiver authority under CAA section 211(o)(7)(D) at the same time it establishes volumes under CAA section 211(o)(2)(B)(ii). Therefore, we are unable to adopt the commenter's suggestion that we "retain the 1.38 billion gallon requirement" and "issue CWCs" for 2025. We also decline to adopt this approach for 2026 and 2027.

EPA is reducing the 2025 cellulosic biofuel volume requirement as waived under the cellulosic waiver authority at the "projected volume available," which includes consideration of the volume of renewable CNG/LNG used as transportation fuel, as described in Preamble Sections III and VII, RTC Section 3, and this Section 8. As described in Preamble Section VII, we do not agree with the commenter's assertion that the trigger for the cellulosic waiver authority ("projected production of cellulosic biofuel" being less than the standard) cannot be met. It has been met for 2025, as described in this final rule.

Comment:

A commenter added that the data through May 2025 does not indicate a "consumption-limited baseline" and that EPA's projections did not account for potential delays in RIN reporting under the biogas reforms in the DRIA.

Response:

We are finalizing the partial waiver of the 2025 cellulosic biofuel volume requirement using the actual cellulosic RIN data available at the time of this writing. Based on this data, 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),[160] and subtracting the number of cellulosic RINs retired

[160] 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.

for reasons other than demonstrating annual compliance (0.08 billion RINs).[161] This volume is lower than the Set 1 Rule's projection of 1.38 billion cellulosic RINs in 2025. Comparing this data with our assessment of expected renewable CNG/LNG consumption in 2025 of 1.25 billion RINs, we conclude that the market reflects a consumption-limited baseline.[162]

We recognize that the biogas regulatory reform provisions 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.[163] Because of this decoupling, we also recognize that there could be delays in RIN generation reporting. However, as described in our analysis in Preamble Section VI, we believe that we are still able to know the number of cellulosic RINs generated for 2025 shortly after the end of the 2025 compliance year. Accordingly, we are making our projection of the cellulosic RINs that will be available for compliance in 2025 based on this known data.

[161] 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.
[162] See RIA Chapter 7.1.3.
[163] 40 CFR 80.125(d) and (e).

9. Economic and Environmental Impacts

9.1 Economic Impacts and Considerations

9.1.1 Costs of the Program

Comment:

Several commenters provided general comments on the high costs associated with the proposed rule, including describing costs for businesses, taxpayers, American consumers, and the environment. For example, a commenter that expressed strong support for the RFS program cautioned EPA that without revisions to the proposal there would be significant fuel cost increases for consumers, structural damage to the energy industry, and potential distortion in the agricultural economy. A commenter stated that the costs of the proposed rule would threaten countless businesses throughout the country, including in Pennsylvania, with higher costs and lost opportunities, especially those that contract with refineries for goods, professional, and mechanical services. Another commenter expressed concerns that the proposal would further raise energy costs for families and small businesses across New Jersey. A commenter estimated that the proposed rule would easily add another 10 cents per gallon in compliance costs that would be passed on to American consumers. Another commenter described the RFS program as a massive government subsidy that funnels billions of dollars from American consumers and businesses into fuels that are substantially more expensive to produce and provide no economic, environmental, or energy security benefits to the American public. The commenter concluded that EPA's DRIA clearly shows the absence of societal benefits compared to the costs of the program. The commenter described a costly shifting in feedstock markets, including providing detailed comments on the price impacts to U.S. soybeans, minimal benefits to U.S. farmers, and high costs to consumers and taxpayers. Lastly, a few commenters stated that there is no statutory requirement that EPA unreasonably increase renewable fuel volumes without regard for cost to both obligated parties and the consumer.

Response:

EPA recognizes that the volumes we are finalizing in this rule are projected to increase the cost of transportation fuel and fuel prices. When establishing these volumes, EPA has considered fuel costs along with the rest of the statutory factors and our review of the implementation of the RFS program to date. Our consideration of these factors is discussed in Preamble Section III. The RFS program has broad support from multiple perspectives. Congress established the RFS program in the Energy Policy Act of 2005 and amended the requirements in the Energy Independence and Security Act of 2007. As noted by the D.C. Circuit, this congressional direction acknowledged "higher fuel prices."[164]

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[164] *CBD* at 171, citing *Sinclair Wyoming*, 101 F.4th 887.

Due to a large step up in BBD volume requirement, we expect increased prices for BBD feedstocks which will increase the production costs. The discussion of price increases is in RTC Section 9.1.4.

There are benefits and positive impacts of increasing the production and use of renewable fuels. Many of the benefits of renewable fuel production and use have not been monetized and/or are only described qualitatively without being quantified. See RTC Section 9.3.

The renewable fuel volume requirements in this rule are also expected to result in significant increases in rural economic development, as discussed in RTC Section 9.1.6.

Comment:

After providing a detailed discussion of how EPA should have projected RIN prices in the future, a commenter concluded that EPA has grossly underestimated the cost of the proposed rule due to not accounting for a realistic RIN cost.

Response:

The cost analysis conducted for RFS program regulations, as well as all EPA regulations, must be conducted to estimate the costs to society (social cost). As directed by the Office of Management and Budget, the social cost analysis must not consider any transfer payments between parties within the U.S.[165] RINs function as a cross-subsidy, effectively increasing the prices of petroleum-based fuels while simultaneously decreasing the prices of qualifying renewable fuels. Because RINs represent transfer payments rather than societal costs it would be methodologically inappropriate to include RIN prices as part of a social cost analysis, as the commenter suggested we do.

In addition to presenting our social cost analysis, RIA Chapter 10 presents a separate analysis that estimates the price impacts of the final volumes. The price analysis accounts for fuel costs, the price of RINs and other Federal subsidies. In this analysis we estimated future RIN prices based on average RIN prices over the previous 12 months for which data was available at the time of analysis. We recognize that these RIN prices may be lower (or higher) than average RIN prices in 2026 and 2027. Because RIN prices are influenced by many different factors that we are not able to project with confidence (*e.g.*, crude oil prices, agricultural commodity prices), we cannot project future RIN prices with any degree of certainty and believe that estimating fuel price impacts using observed RIN prices over the previous 12 months is a reasonable approach in light of these limitations. We believe the inclusion of this analysis is appropriately responsive to these comments.

Comment:

A commenter stated that at the same time as taxpayers will be required to respond to the increased costs from the proposed rule, increased mandates for advanced biofuels and BBD will

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[165] OMB, "Circular A-4," September 17, 2003. https://www.whitehouse.gov/wp-content/uploads/2025/08/CircularA-4.pdf.

increase taxpayer expenditures through subsidy programs like the 45Z credit. EPA's DRIA detailed how the 45Z credit, first enacted in the Inflation Reduction Act of 2022, is expected to cost taxpayers anywhere from $0.20-$0.70 per gallon for biodiesel in 2026 and 2027. However, the commenter noted that EPA's estimates were completed prior to passage of OBBB, which significantly increased the total potential expenditure value of the 45Z credit by eliminating consideration of ILUC in biofuel carbon intensity calculations. The credit's overall cost is now expected to soar, with the Joint Committee on Taxation estimating the recent extension will cost an additional $10.5 billion in Fiscal Year 29 alone. The commenter asserted that Federal biofuel subsidies directly influence industry decisions and consumption levels and that EPA's DRIA acknowledges U.S. tax policy's distortion of BBD markets.

The commenter concluded that simultaneously subsidizing and mandating the production of food-based biofuels in the U.S. hurts both consumers and taxpayers. The commenter stated that unless EPA's final advanced biofuel and BBD RVOs are set at levels that do not distort markets, both groups are likely to face higher costs – exacerbated by the recent expansion of Federal tax breaks for mature biofuels. The commenter noted that the higher EPA biofuel volumes are set, the higher the 45Z credit cost to taxpayers since the 45Z credit is contingent on per-gallon biofuel production levels.

Similarly, another commenter noted that a portion of the cost of the proposed rule is also born by taxpayers who subsidize biofuel production through tax credits.

Another commenter stated that impacts of the proposed rule, which include a reduced number of RINs generated for imported renewable fuel and domestically produced renewable fuel made from foreign feedstocks, would occur at the same time as the ongoing transition for biofuel tax incentives from subsidizing the *consumption* of biofuel to subsidizing the *production* of biofuel. The commenter described this tax incentive transition as a significant departure from the tax incentive backdrop against which the RFS program has existed for two decades. The commenter concluded that, collectively, these policy changes will materially alter trade flows, commodity prices, and market incentives, with different consequences in different regions of the country.

Response:

The cost analysis conducted for EPA rulemakings estimates all costs to society as required by OMB Circular A-4, including those costs which otherwise would be offset by the 45Z biofuel production subsidies. Although the 45Z biofuel production subsidies are not singled out in the societal cost analysis, they are included when estimating the No RFS Baseline, since the 45Z subsidies are established separately from the RFS program. Also, the estimate of the RFS program's effect on fuel prices accounts for the impact of the 45Z subsidies.

In the final rulemaking analyses, the 45Z blending subsidies have been updated from blending to production subsidies as prescribed in the OBBB. The 45Z production subsidies favor biofuels produced from domestic feedstocks and those sourced from North Americal over feedstocks imported from other countries, increasing demand of these domestically produced feedstocks. For more information about how the tax credit considerations described by the commenter factor into our cost analysis for this final rule, see RIA Chapters 2.1 and 10.4.

Comment:

A commenter stated that EPA relied on outdated baselines in the economic analysis, specifically noting that crude oil price projections relied on by EPA are from AEO2023. The commenter stated that EPA must update the economic analysis and RVOs to reflect AEO2025, reasoning that it is not reasonable to cherry pick the AEO2023 forecast, which the commenter describes as bolstering EPA's blending proposal. The commenter then noted that EPA expressed the intention for the final rule to reflect the latest AEO. However, the commenter stated that obligated parties must have an opportunity to review the new data from AEO2025 before publication of the final rule and that obligated parties cannot plan for compliance if the rule will change at final publishing based on an updated report.

Another commenter criticized EPA's use of outdated soybean oil (SBO) prices, stating that it resulted in a significant underestimation of the proposed rule's cost. The commenter noted that SBO prices rose on the announcement of the proposed volumes, and S&P projected feedstock prices would increase in the context of the proposed volumes, the lower 45Z credit, and proposed 50% import RIN reduction. The commenter also stated that the crude oil prices used in the analysis were too high. The impact of inaccurately calculating the difference between the price of crude oil and "bean" oil is demonstrated by modeling the "BOHO spread," or the price difference between bean oil and heating oil, which is a proxy for ULSD. The commenter explained that the BOHO spread had more than doubled from $0.80 to $1.72 since the publication of the proposed rule. The commenter stated that when the BOHO spread increases, the RIN value must rise to cover the spread between the price of bean oil and ULSD, raising total RFS compliance costs. The commenter calculated the high BOHO spread at $2.25 per gallon and the low BOHO spread at $0.66 per gallon and demonstrated that RFS program costs increase with a wide BOHO spread while falling when the spread is narrow. The commenter argued that if the BOHO spread remains at these high levels, the proposed volumes were expected to double the cost of the RFS program due to increased RIN obligations, 50% reduction in RINs on foreign feedstocks, and the implied conventional volume exceeding the ethanol blendwall. The commenter stated that failure to consider the BOHO spread rendered EPA's analysis of costs and benefits inaccurate and insufficient to support finalizing the rule as proposed.

Response:

Each time we conduct a cost analysis for the RFS program, we update the analysis with the latest price projections and other important information upon which the cost analysis is based. These updates can even occur between the proposed and final rules if updated projections have occurred during the middle of the rulemaking cycle. While AEO2025 was released prior to the publication of the Set 2 proposal, it was necessary to consider the time required to update the baseline, cost, and other analyses. In this case, we determined that the updated projections could not be completed prior to the issuing the Set 2 proposal. For this reason, we stated that the AEO2025 could not be adopted for the Set 2 proposal analysis but would be included in the final rule analysis. The various updates can affect the No RFS baseline volumes as well as the magnitude of the cost analysis, which together will affect the overall estimated costs of the RFS program.

Between the analysis conducted for the Set 2 proposal and this final rule, multiple updates were incorporated to the final rule baseline and cost analyses that affected both the No RFS Baseline and cost analysis—the No RFS Baseline volumes affect the overall cost estimate:

- Petroleum product (gasoline and diesel fuel), natural gas and electricity prices were updated from AEO2023 to AEO2025.
- Corn prices were updated to the most recent USDA price projections, and DDGS prices were updated to the most recent FASOM projections. Soybean, corn oil and FOG prices were updated based on a projection for how the increased demand for these feedstocks are expected to impact their respective markets. Due to the uncertainty in projecting prices, sensitivity analyses were also conducted at higher and lower soybean, corn, and FOG prices.
- The carbon credit values for California, Oregon, and Washington were updated for the No RFS Baseline.
- The rates of renewable diesel blended into diesel fuel in California, Oregon, and Washington were updated as these rates can affect the volumes for the No RFS baseline.
- Changes to the 45Z credit were estimated based on the changes in OBBB and incorporated into the No RFS Baseline analysis.

We believe that these updates, which include the most up-to-date petroleum and soybean oil price data available to us at the time we conducted our analysis for this final rule, respond appropriately to the issues raised by the commenters. Also, while we did not analyze the cost impacts of the proposed RFS volume requirements based on AEO2025, we did add state in the Set 2 proposal that the lower crude oil prices in AEO2025 would likely increase the estimated RFS program costs. AEO2025 was released on April 15, 2025, providing stakeholders with sufficient time to consider the impacts of the changes in these projections on the analyses provided in the Set 2 proposal. Interested stakeholders could reasonably estimate the likely impacts of revising our estimates using AEO2025 based on the information provided in the Set 2 proposal.

Comment:

The commenter also stated that the loss of the 45Z credit for imported fuels and imposition of the 50% import RIN reduction meant that the RIN value needed to increase dramatically relative to EPA's assumed prices for biofuel producers to break even. The commenter argued that EPA's analysis did not consider the large increases in SBO prices or projected higher RIN prices, nor did it consider that basing the prices of other feedstocks like DCO and FOG off the historic spread between SBO spot prices and these commodities was inaccurate and reflective of old market dynamics.

Response:

The proposed IRR provisions are not being finalized in this rule. While the biofuel tax credit was reduced in quantity and changed from the 40A subsidy which was a blending subsidy, to the 45Z subsidy which is a production cost subsidy, it still is in place. The reduction in the subsidy for imported fuels may contribute to higher RIN prices. We have updated our methodology for estimating biofuel feedstock prices (*i.e.*, soybean oil, corn oil, canola oil, and FOG) with increasing demand for these feedstocks. This change in methodology results in higher projected costs of production for biodiesel and renewable diesel and contributes to higher projections for the total cost of this rule. We are still projecting unrefined corn oil and FOG (waste) prices to be priced lower than virgin soybean and canola prices due to their lesser quality and likely need for further refinement prior to being processed into biofuel.

Comment:

A commenter stated that EPA's limited assessment of economic impacts resulting from its proposal fails to meet applicable legal standards requiring comprehensive assessment of economic impacts, resulting in a DRIA that underestimates the impacts of the proposed unprecedented action. The commenter generally asserted that the DRIA fails to comply with statutory requirements for economic analysis by failing to adequately cite authorities for the analysis and by conducting an insufficient economic analysis.

A commenter identified a few specific revisions/clarifications needed in the DRIA:

- Tables 2.1.5-1 and 2 of the DRIA are imprecise.
  - The volumes on pages 77 and 79 of the DRIA do not match. In Sections 7.2 and 7.4 of the DRIA, the advanced number of RINs is 192 million, yet in Tables 2.1.5-1 and 2, the advanced number of RINs is 197 million. This needs to be corrected. EPA must also provide ethanol volumes within these tables.
- Multiple calculations could not be checked for accuracy with the information provided in the DRIA. These include:
  - EPA's calculation of retail costs for E15 in Chapter 2.1.1.3.
  - EPA's calculation of four-year averages in Table 2.1.3.1-8.
  - EPA must provide additional information to confirm these calculations are correct.

Response:

DRIA Tables 2.1.5-1 and 2 summarized the No RFS Baseline in terms of actual volumes and ethanol-equivalent volumes, while DRIA Chapter 7 lists the volumes in RINs for "other advanced biofuels" in the year 2023. The No RFS Baseline may not exactly match the historical volumes in these tables because they represent different time periods. The total volume of corn ethanol was listed in Tables 2.1.5-1 and 2, although the ethanol types in the marketplace (*e.g.*, E10, E15 and E85) were not listed there. Instead, the projected volumes of E10, E15, and E85 were estimated in Chapter 7.5.

The E15 retail cost (which applies to the E85 cost) was calculated in the DRIA by multiplying the retail station upgrade cost by the capital cost amortization factor (0.16) in Table 2.1.1.1-1 and then divided by the annual volume of ethanol contained in E15 sold at retail stations. A footnote is added to that section to describe the methodology in the final RIA (see Chapter 10.1.2.1.1).

The four-year averages were calculated from the values in the table (the average of the year being analyzed, and the previous 3 years), for estimating the 4-year average volume of economic biodiesel volume. The economic biodiesel volume in the previous 3 years was initially estimated in the Set 1 RIA, and all the calculations are contained in the spreadsheet "Biodiesel Renewable Diesel No RFS Baseline for Set 2 Final Rule," available in the docket for this action.

Comment:

A commenter argued that given the extraordinary cost of the proposal, EPA must comply with Executive Order 14192 by identifying the elimination of 10 prior regulations to offset the incremental costs associated with the proposal. A few other commenters asserted that the costs of the proposal have not been offset as required by the President's deregulatory executive order. Relatedly, a couple of commenters said that imposing these RFS compliance costs on obligated parties and ultimately the public contradicts the deregulatory priorities of the current Administration, which have been highlighted in a myriad of recent executive orders aimed at reducing regulatory burdens.

Response:

EPA has taken deregulatory actions. A complete list of the regulatory and deregulatory actions is available at: https://www.reginfo.gov/public/do/eAgendaMain.

Comment:

A commenter asserted that the cost of compliance with the proposed rule would provide a strong incentive for obligated parties to export their gasoline and diesel to lower their RVOs, reducing the volume of essential products available to U.S. businesses and consumers. This in turn reduces the amount of fuels available for consumption domestically thereby undermining energy security. The commenter also stated that in more extreme cases, some obligated parties could choose to shutter their facilities as has happened in California, which could also reduce the volume of transportation fuels available in the U.S. market.

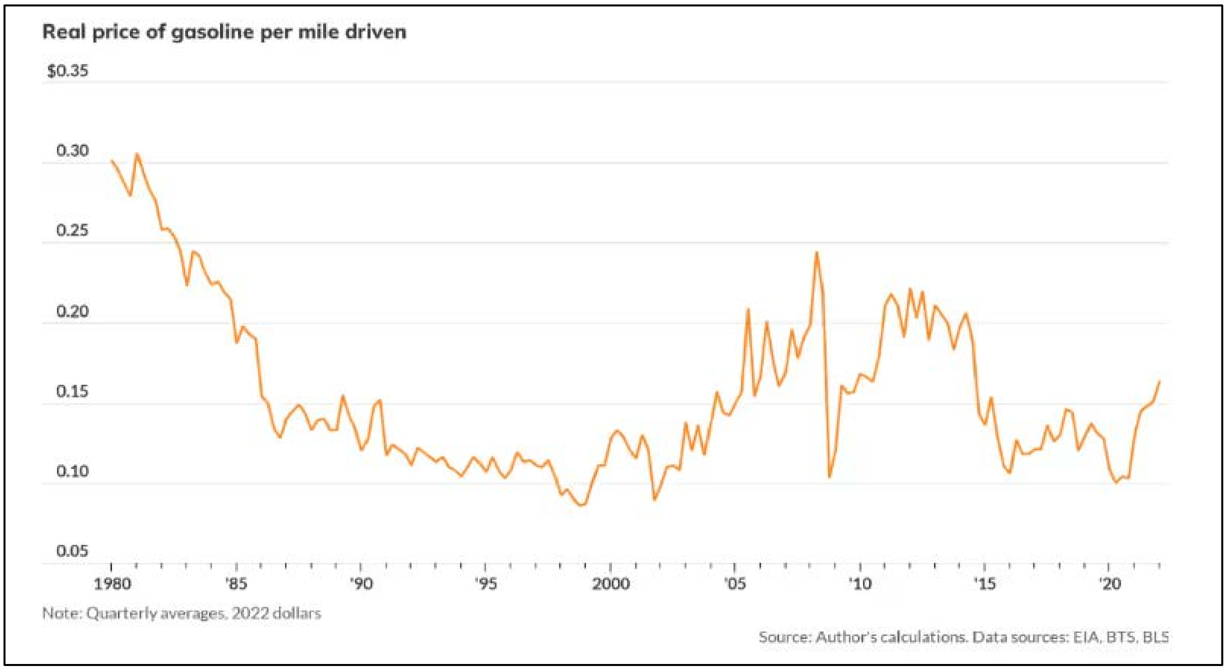
Response:

EPA does not agree with the claim that compliance costs will cause U.S. refiners to export their product elsewhere. Compliance costs are typically passed on in the form of higher finished fuel prices to the end users. EPA and others have carefully and repeatedly evaluated this issue and finds that the costs of compliance to obligated parties from the RFS program are passed along to consumers in the prices of gasoline and diesel fuel.[166] EPA and others have found that both the RIN costs and the RIN value (*i.e.*, the ability for the sale of the RIN to reduce the effective price of renewable fuels) are passed on to consumers in the price of blended transportation fuel. Because of this, any obligated parties that choose to export gasoline and diesel to avoid RFS

[166] 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 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.

obligations would receive a lower price for these fuels than they would in domestic markets, offsetting any potential benefits of avoided compliance costs.

From an energy security perspective, however, to the extent that energy security is defined as "uninterrupted availability of energy sources at an acceptable price,"[167] the higher prices to the consumers on account of higher compliance costs can understandably be a concern. Recent gasoline prices, though, have been relatively low (compared to 11+ years ago) on a per-mile cost basis, as shown in the figure below.[168] More recently military action in the Middle East has increased the prices of petroleum fuels in the U.S. and around the world, but if that military action is not sustained over a long period, then we can expect petroleum prices to decrease. At relatively lower petroleum prices, the costs of the RFS program would be absorbed by the U.S. transportation market without triggering an economic, nor energy security, concern.



Source: Nutting, Rex, "Opinion: Gas prices are way up, but real cost of driving a mile was higher for most of the past century," *Marketwatch*, March 8, 2022. https://www.marketwatch.com/story/the-price-of-gasoline-isnt-really-at-a-record-high-in-fact-the-inflation-adjusted-cost-of-driving-a-mile-was-higher-for-most-of-the-past-century-11646770318.

We evaluate the potential impact of the final volume standards on fuel prices in RIA Chapter 10. To understand the impact of this rule on refinery closures, see RTC Section 9.1.8.

[167] IEA, "Energy Security." https://www.iea.org/topics/energy-security.
[168] Gasoline prices started out the year in 2026 much like that of 2019.

Comment:

The commenter noted that not all renewable fuel plants could secure adequate volumes of SBO due to limited freight line or Jones Act vessels, and shipping costs for domestic rail were nearly double the cost of shipping feedstocks from Asia.

Response:

For transporting soybean oil to the renewable diesel plant, it could be transported by rail, truck, barge, or ship. It is not unusual for a certain volume of renewable diesel feedstocks to be shipped by multiple modes. For example, a certain batch of soybean oil created at a soybean crushing facility in the Midwest could be transported by rail or barge to the Gulf Coast, put on a Jones Act ship and transported to a terminal on the West Coast, and then transported by truck to a renewable diesel plant. Once renewable diesel is produced, the renewable diesel could then be transported by truck to a terminal. Alternatively, the soybean oil produced at the crushing facility could be transported by rail directly to the West Coast renewable diesel plant, although the rail cars of soybean oil may need to be transferred over to a truck at a rail-truck transfer facility if the renewable diesel plant cannot accept rail cars. This example highlights the complexity of transporting these feedstocks and fuels, as well as the flexibility. Thus, as the commenter stated, renewable diesel plants may have a hard time obtaining soybean oil by rail or Jones Act vessels, but the renewable diesel producers could find a different means, or combination of means, to transport the soybean oil to their plant. Alternatively, the renewable diesel plants could purchase a different feedstock for their plants.

One consideration is whether the volume of vegetable oil or FOG is overwhelming the transportation system which must move the material from the agricultural sector to the production facilities. Based on the 2025 standards, the volume of BBD totaled 3.9 billion gallons in 2025, and requires a similar volume in feedstock. The 3.9 billion gallons is equivalent to about 14 million tons of feedstock needing to be transported. In the U.S., the railway industry, Jones Act ships, and trucking industry moved about 1.8, 1, and 11.2 billion tons of goods, respectively, in 2023.[169,170] Thus, as a percentage of the total amount of product moved by each of those transportation means, the total volume of BBD comprises 0.7% of rail, 1.3% of Jones Act shipping, and 0.1% of trucking volume. In some cases, a single batch of soybean oil could require multiple demands on a transportation mode, such as using the rail system twice. Only a partial portion of the volume of soybean oil which must be transported is expected to require Jones Act shipping. The reported growth in transportation demand is about 1.2% per year, thus, the transportation systems in the U.S. are always expanding their capacities. The impacts of the projected volumes of biodiesel and renewable diesel in the final volume standards on infrastructure are discussed further in RIA Chapters 8.2 and 8.3, respectively.

Concerning the comments on rail and Jones Act shipping costs, as the production and consumption of BBD increases, the distribution system will become more efficient. For example,

[169] DOT, "Moving Goods in the US; Freight Facts and Figures," 2025. https://data.bts.gov/stories/s/Moving-Goods-in-the-United-States/bcyt-rqmu.

[170] American Maritime Partnership, "Jones Act – Cornerstone of US Maritime Safety and Security," 2026. https://www.americanmaritimepartnership.com/u-s-maritime-industry/jones-act-overview.

unit train shipments are much more time- and cost-efficient than manifest rail.[171] Similarly, Jones Act ships can be made more cost efficient by moving products in larger ships. Thus, larger volumes of renewable fuels could eventually lower the costs of these distribution systems and are likely to increase the availability of the feedstocks and their products.

Comment:

A commenter argued that EPA's failure to set achievable implied conventional renewable fuel volumes based on actual ethanol demand unnecessarily inflates the costs of the RFS program without increasing midlevel ethanol blends or improving products. The commenter noted that EPA admitted that even with the mandates of the RFS program, the use of E15 and E85 have not been cost effective. The commenter concluded that EPA has imposed substantial costs on consumers of gasoline since 2015, when it first set the implied conventional renewable fuel volume requirement at 15 billion gallons in an effort to signal the market to increase the concentration of conventional biofuels in the gasoline pool. However, the commenter provided data showing that there has been no correlation between D6 RIN prices and ethanol blending.

The commenter calculated that the marginal cost of providing additional ethanol through E15 and E85 was approximately $770 per gallon in 2026 and $349 per gallon in 2027. The commenter argued that this cost was unreasonable under any "interpretation of what a balanced policy should be." The commenter stated that reducing EPA's unrealistic 15-billion-gallon mandate would not materially change E15 infrastructure or consumption but would dramatically decrease the cost of RFS compliance by 55%.

Furthermore, the commenter argued that the Clean Air Act (CAA) requirement that EPA base volumes on its "review of the implementation of the program" should have led EPA to conclude that high RIN prices have not resulted in higher ethanol blend rates, that high implied conventional renewable fuel volumes have not increased E15 use, and that this approach has caused unnecessarily high costs. The commenter cited *Loper Bright Enterprises v. Raimondo*, arguing that EPA must reevaluate its approach to the implied conventional renewable fuel mandate.

The commenter cited a Turner Mason & Company (TM&C) analysis that found annual compliance costs could jump to $67–69 billion during the next two years based on a host of interrelated policy issues, including recent changes to the 45Z credit to remove indirect land use change emissions from the credit estimation process. The commenter stated that the most influential issue on increased compliance costs comes from setting the implied conventional renewable fuel volumes higher than the gasoline-ethanol blendwall being the most substantial single factor in driving up compliance costs. The commenter argued that if EPA ensured that the implied conventional renewable fuel mandate was set no higher than the amount of ethanol actually blended and maintained the total renewable volume, it would reduce compliance costs

[171] Zhang, Zhipeng, Chen-Yu Lin, Xiang Liu, Zheyong Bian, C Tyler Dick, Jiaxi Zhao, and Steven Kirkpatrick. "An Empirical Analysis of Freight Train Derailment Rates for Unit Trains and Manifest Trains." *Proceedings of the Institution of Mechanical Engineers Part F Journal of Rail and Rapid Transit* 236, no. 10 (April 14, 2022): 1168–78. https://doi.org/10.1177/09544097221080615.

by approximately $37 billion in 2026 and $38 billion in 2027 without changing the amount of ethanol blended.

The commenter suggested that setting the implied conventional renewable fuel volumes at the blendwall and setting advanced biofuel volumes limited to North American feedstocks could reduce compliance costs by more than 60%, with relatively minor changes and reductions in volumes.

Response:

The conventional fuel standard is set at 15 billion gallons to incentivize the blending of ethanol in E10, E15, and E85 up to that volume. Because ethanol does not usually rise to that volume of blending in practice, some BBD makes up the difference. If EPA were to establish the volume requirements such that the implied conventional renewable fuel volume requirement was less than 15 billion gallons, but set the advanced biofuel and BBD volume requirements such that the same total volume of biofuel was required, D6 RIN prices might be lower, but the cost to society of the program would likely be the same since RIN prices are not the same as the societal costs. It is also important to recognize that the cost of the implied conventional renewable fuel standard is not simply the D6 RIN price multiplied by the implied conventional renewable fuel standard. This is because the bulk of the implied conventional renewable fuel standard is met with corn ethanol, the cost of which is far lower than the D6 RIN price. As discussed in RIA Chapter 10, EPA's analysis has shown that higher RIN prices, on average and at the nationwide scale, are transfer payments that are paid back to refiners in the form of higher terminal gasoline and diesel prices. These increases in the wholesale gasoline and diesel prices resulting from RFS compliance obligations are then largely offset when these fuels are blended with renewable fuel such as ethanol and biodiesel. Prices for these renewable fuels are effectively reduced when parties separate and sell the RINs generated for these fuels.

Contrary to the claims made by the commenter, the implied conventional renewable fuel standard as estimated in this and previous RFS rulemakings has in fact caused greater sales of higher-level ethanol blends. The following table summarizes our estimate of the volume of ethanol sold as E15 and E85.[172] Note that the volumes in this table represent all sales of E15 and E85, not only the sales of these fuels attributable to the RFS volume requirements.

Volume of Ethanol Sold (or Projected to be Sold) as E15 and E85 by Year (million gallons)

	2021	2022	2023	2024	2025	2026	2027
E15	54	66	80	93	106	149	168
E85	241	251	260	272	283	328	353

Source: Set 1 RIA Chapter 6.5.2 and Set 2 RIA Chapter 7.5.2.

The estimates, based on data we evaluated, show that the volume of ethanol sold as E15 has more than tripled in 6 years, while the volume of ethanol sold as E85 has increased by about 50%. The volume of E85 ethanol has increased despite the fact that the number of fuel-flexible vehicles has decreased over time. Because our cost analysis shows that higher ethanol blends are not cost-effective relative to petroleum (before considering the impact of the RFS program on the

[172] For more information, see RIA Chapter 7.5.

prices of these higher-level ethanol blends), we conclude that increases in ethanol contained in higher-level ethanol blends can be attributed to the RFS program.

We do not agree with the commenter's estimate that marginal cost of providing additional ethanol through E15 and E85 was approximately $770 per gallon in 2026 and $349 per gallon in 2027. In table 10.4.1-1 in RIA Chapter 10, we summarize our estimated marginal cost for various biofuels. We estimate that the marginal cost of the 5% of additional ethanol in E15 is on the order of $6 per gallon, and ~$3.60 per gallon for the ~65% of ethanol in E85, both far lower than estimated marginal costs provided by the commenter. These costs are higher than cost estimates made in previous rulemakings due to updated information on the cost to revamp retail stations to accommodate higher ethanol blends. We expect these marginal costs for E15 to decrease over time because the throughput volume per retail station of E15 is increasing, which lowers the per-gallon cost of the retail station revamps. Furthermore, if E15 starts to displace E10 in a meaningful way, particularly in certain markets, refiners will likely switch over to a lower octane E15 blendstock for oxygenate blending (BOB). This would save on refining costs for both E15 and E85, thus lowering the cost attributed to ethanol for higher ethanol blends.

Comment:

Commenters argued that increasing RVOs without corresponding domestic demand growth will create market distortions, particularly for small refineries with limited blending capacity or geographic constraints, a commenter encouraged EPA to set the statutory minimums for advanced biofuels and BBD and eliminate the implied conventional renewable fuel mandate in order to dramatically reduce the cost of the program while maintaining the vast majority of the renewable fuels blending.

Response:

Since most biofuels simply displace petroleum fuels at the point of use, the biofuel is blended into petroleum fuels and the consumer simply consumes the blended biofuel-petroleum fuel product and usually is unaware of the difference.

Refiners are required to either blend the requisite amount of biofuel into their produced fuels, or purchase RINs for blending downstream of the refinery. While the difference in whether refiners can blend in biofuels or purchase RINs affects how they comply, due to RIN price passthrough (*i.e.*, the phenomenon whereby the excess cost of the RIN is passed back to the refinery in the form of higher terminal prices), we expect that this leads to minimal distortions in the marketplace.

There is support for the blending of BBD into diesel fuel. This is evident by the separate federal 45Z production subsidies established by Congress which represents U.S. citizens, and the many state blending mandates and blending subsidies. Also, if we reduced the BBD volume to a minimal value, it would reduce many of the positive impacts expected to result from the volumes we are finalizing in this rule (see Preamble Section III for a summary of these impacts). The response to the previously addressed comment describes how reducing the conventional mandate will not necessarily reduce the costs of the RFS program, assuming that the alternate volume standards force the same volumes of biofuels.

Comment:

A commenter questioned EPA's inclusion of additional costs for "fuel economy" of biodiesel and renewable diesel in its "total costs" estimates. The commenter argued that such additional costs were not appropriate, as the most common blend of biodiesel (B20) has minimal to no impact on fuel economy. The commenter cited millions of miles of fleet data showing that B20 has the same fuel economy and horsepower, calling into question the basis for EPA's equivalence values that give renewable diesel greater credit based on an "incorrect theory" that it displaces more petroleum-based diesel fuel. The commenter stated that nonetheless, biodiesel production's estimated total costs, even under EPA's analysis, are still less than those of renewable diesel production.

Response:

It is generally accepted that differences in energy content predict differences in fuel economy. One such study assessing the fuel economy of ethanol showed that the measured lower energy density of ethanol was a good predictor for its fuel economy.[173] Despite ethanol's much lower energy density (33% less than gasoline), when only blended into gasoline at 10 vol%, drivers usually cannot observe a decrease in fuel economy. A primary reason why drivers cannot observe a decrease in fuel economy when driving on E10 is that other factors (*e.g.*, driving behavior and driving speed, use of passenger compartment temperature control, ambient temperature, tire pressure, etc.) also impact fuel economy and obscure ethanol's fuel economy effect. Since biodiesel is only 8% less energy dense than diesel fuel, even high blends of biodiesel will not cause a noticeable reduction in fuel economy relative to B0. Even though drivers may not notice a difference in fuel economy, we calculate its cost and include it in our social cost analysis.

Comments on the equivalence values for renewable diesel, jet fuel, and naphtha are discussed in RTC Section 11.1.

[173] Roberts, Matthew C. "E85 And Fuel Efficiency: An Empirical Analysis of 2007 EPA Test Data." *Energy Policy* 36, no. 3 (January 2, 2008): 1233–35. https://doi.org/10.1016/j.enpol.2007.11.006.

9.1.2 Energy Security

Comment:

Many commenters state that this rule will result in energy security benefits and improve energy independence by stimulating domestic production and expanding domestic fuel supply, and increasing reliance on diverse sources of energy, all of which would reduce dependence on imported petroleum and thereby insulate consumers from global energy market volatility.

Response:

EPA agrees with commenters that higher domestic production and supply of renewable fuels will reduce dependence on imported petroleum and strengthen U.S. energy security. A reduction in U.S. net petroleum imports reduces financial and strategic risks caused by potential sudden disruptions in the supply of imported petroleum to the U.S., thus increasing U.S. energy security and insulating consumers from volatility in global energy markets. EPA also agrees with commenters regarding how reliance on diverse sources of supply could benefit energy security. Throughout the history of the RFS program, EPA has repeatedly recognized the benefits to U.S. energy security from diversification of fuels, particularly in the context of BBD fuels. Additionally in RIA Chapter 6.5, we present a preliminary analysis of the implications of feedstock diversification (one step removed from fuel diversification) on volatility in transportation fuel prices.

Comment:

A commenter argued that EPA may have underestimated the benefits to energy security because it provides a limited assessment of the impacts of the overall proposed volumes on energy security. They argued that the estimated benefits would be even higher with higher volumes. They further argued that EPA's analysis ignores that, with increasing volume requirements, domestic production of cellulosic biofuels has been the significant source of growth, representing 95% of total D3 RIN generation in 2024 (compared to 82% in 2015). By its limited analysis, the commenter contended, EPA underestimates the energy security benefits of increased cellulosic biofuels.

Response:

Comments received on the volume standards in this rule are addressed in RTC Section 6.1.

EPA is unaware of an existing alternative methodology that estimates energy security benefits to the U.S. from the use of renewable fuels and specifically from the use of cellulosic biofuels per se. However, the energy security benefits of increased use of cellulosic biofuels arising from displacing use of fossil fuels is represented in the quantified energy security impacts presented in RIA Chapter 6.

Comment:

Several commenters asserted that the negative impacts of the proposed rule on refiners will harm national energy security. A commenter strongly advocated for reforms to the RFS program, arguing that the proposed rule will lead to more refinery closures, decreased refining capacity, and diminished energy independence. Another commenter noted that if the proposed rule results in challenges for independent refiners, that could compromise national fuel security for years to come.

Response:

Comments received regarding the impact on refiners from this rule are addressed in RTC section 9.1.8.

Comment:

A commenter noted that EPA acknowledged that the RVOs will lead to higher prices and require infrastructure investment to transport biodiesel from the points of production to locations where it can be consumed. The commenter then stated that these higher prices directly harm U.S. energy security, which is broadly defined as the uninterrupted availability of energy sources at an acceptable price.

Response:

Comments regarding the impact of the rule on prices are addressed in RTC Section 9.1.5.

Comment:

Multiple commenters raised concerns about the proposed rule's potential to increase imports of biofuels and feedstocks and consequently decrease U.S. energy security. One commenter argued that the final volumes would likely require increased imports of BBD or vegetable oil, which they argue would increase risks to energy security and energy independence. Additionally, several commenters noted that, since bio-based feedstocks are global commodities, they are subject to price shocks from uncertainty in supply and demand conditions in agriculture. Coupled with proliferation of biofuel mandates and trade restrictions, these commenters argue these shocks will add to volatility in feedstock prices. They further stated that EPA failed to consider the energy security detriments of increasing imports of biofuels and feedstocks to meet the proposed advanced biofuel volumes.

Additionally, one commenter noted that EPA assumes energy security benefits from imported renewable fuels and feedstocks while contending that some crude oil imports are reduced to achieve energy independence. They further argued that the actual costs may be significantly higher and the benefits significantly lower than EPA's estimates. In a similar vein, one commenter concluded that EPA's proposal simply shifts the dependence on foreign energy sources from one form of energy (crude oil) to another (bio-based feedstocks). They further stated that the crude oil refined by U.S. refiners was mostly sourced from North America, with

Canada as the largest supplier, and that the integrated infrastructure of North America has made the U.S. largely energy secure over the past 15 years.

Response:

We agree with the commenters that imports of biofuels and biofuel feedstocks may have implications for U.S. energy security. However, we disagree with those commenters who state or imply that the implications of these imports for U.S. energy security are uniformly negative. Bio-based feedstocks are global commodities and, as discussed in multiple chapters across the RIA (Chapter 3, Chapter 7, and Chapter 9), the Final Volumes are estimated to intensify the competition for limited feedstocks, most notably vegetable oils and FOG, relative to the previous RFS volume standards. We note that the same is not necessarily true for imported biofuels specifically, as our analyses generally project that these imports will decline substantially in 2026 and 2027 compared to 2024 and previous years, due to changes in federal tax incentives (see Chapter 3 and Chapter 7). Even so, exposure of the U.S. renewable fuel and biofuel feedstock supply to global supply and price volatility risks, and the associated potential risks to energy security benefits from this exposure, are understandably a concern. RIA Chapter 6.5 considers the potential impacts of increased diversification of biofuels and biobased feedstocks on volatility in transportation fuel prices and hence energy security. This analysis includes the potential impact of imported biofuels and biofuel feedstocks on U.S. energy security. We note that commenters did not suggest any methods by which we should conduct such an analysis.

When comparing possible changes in U.S. oil and renewable fuel imports, EPA estimates that this rule will reduce overall imports of liquid fuels to the U.S., improving the U.S.'s energy security position. Moreover, since overall imports of liquid fuels to the U.S. are reduced, this rule moves the U.S. towards the RFS goal of increased energy independence. The impact of the final volume standards on costs is discussed in RIA Chapter 10. RTC Section 9.1.1 addresses comments on costs of the program on transportation fuels. We agree with the commenter that the mix of U.S. crude oil imports and exports has changed in recent years and that energy infrastructure has changed over that period. RIA Chapter 6 also summarizes the changes in U.S. oil trade posture in recent years and analyzes the implications of this changing posture for overall U.S. energy security.

Comment:

A commenter noted that EPA has previously recognized that energy security is furthered by diversification of fuels, particularly with respect to the BBD category. They noted that EPA has since focused on "net petroleum imports," noting that the United States has been a "modest net petroleum exporter," and now appears to be considering "changes in imports and exports of renewable fuels and renewable fuel feedstocks."

Another commenter stated that the proposed rule does not adequately account for the increased energy security provided by the U.S.'s reliance on import-based renewable fuels that contribute to the U.S. energy supply. In particular, the commenter noted that one of the major purposes of the RFS program is to reduce the reliance on imported petroleum products by incentivizing the use of available renewable fuel alternatives.

Response:

EPA agrees that fuel diversification will be beneficial for U.S. energy security. As mentioned above, RIA Chapter 6.5 considers the potential impacts of increased diversification of biofuels and biobased feedstocks on volatility in transportation fuel prices and hence energy security.

EPA appreciates the commenter's perspective and agrees that energy security is an important consideration under the RFS program. Aside from its own analysis, EPA is currently unaware of any other methodology that carries out a detailed assessment of the impacts of including renewable fuels on energy security.

Comment:

A commenter stated that EPA treats biodiesel and renewable diesel as interchangeable, overlooking distinct market dynamics and differences in international production practices including differences in worker and environmental protections in international biodiesel production. This in turn diminishes the energy-security value of preserving a defined role for biodiesel in the RFS program. They further argued that U.S. biodiesel producers use foreign feedstocks based on market efficiencies (*e.g.*, Canadian canola; Mexican soybean oil from U.S.-grown soybeans), whereas U.S. Renewable diesel relies more on imported used cooking oil (UCO) and tallow to capitalize on policy incentives. They noted that since EPA acknowledges that the U.S. has substantial unused biodiesel capacity that could be utilized, domestic biodiesel production could grow without new capital investment. To this end, they noted that EPA should not only institute a biodiesel-specific obligation that supports the use of this existing production capacity but also set overall advanced volumes high enough to enhance U.S. energy security by ensuring that all existing domestic biofuel resources can produce for the market. They argued that if EPA does not adopt their proposed approach, there would be reduced competition, which would have negative implications for energy security.

Response:

EPA has not considered biodiesel and renewable diesel as interchangeable in the analyses that support this final rule. For example, we have projected different costs of production for these fuels and in projecting the available supply we have considered differences in the locations of existing facilities and access to feedstocks, existing production capacity, and access to markets with additional incentives such as state low carbon fuels programs.

As discussed in greater detail in Preamble Section III, we recognize that biofuels produced in the U.S. from domestic feedstocks provide greater benefits for some of the statutory factors, such as rural economic development. We expect that the current structure of the 45Z credit will provide significant advantages for domestic biofuel producers using North American feedstocks relative to imported biofuels and biofuels produced from feedstocks sourced from countries outside North America. If the volume requirements for BBD, advanced biofuel, and total renewable fuel were met entirely with domestically sourced biofuels, this would require existing domestic BBD producers (including biodiesel producers) to operate at an average utilization rate of approximately 90%. While we recognize that there may be some situations where imported biofuels can compete with domestically produced biofuels, we expect that the relatively high volume requirements we are establishing in this final rule, in combination with the current structure of the 45Z credit, will provide strong support for all domestic biofuel producers and feedstock suppliers, including biodiesel producers.

In this final rule we are not establishing a biodiesel-specific volume requirement. Such a request is beyond the scope of this action. Additionally, establishing a new requirement specifically for biodiesel would be inconsistent with EPA's implementation of the RFS program to date. It would also add a new renewable fuel volume requirement beyond those established by Congress. It is not clear that EPA has the authority to establish a volume requirement for a category of renewable fuel beyond the four categories defined by Congress in EISA, especially without providing notice of our intent to do so and an opportunity for public comment. Finally, we do not believe that a separate volume requirement specific to biodiesel is necessary in light of the strong support for all renewable fuel producers, including biodiesel producers, provided by the volume requirements we are establishing for 2026 and 2027 in this action.

9.1.3 Impacts of Standards on RIN Prices

Comment:

A few commenters provided general comments that RIN prices have grown increasingly burdensome since the inception of the RFS program. A commenter stated that the mere announcement of this proposed rule elevated RIN prices by 30%.

Response:

RIN prices have fluctuated throughout the history of the RFS program. For example, D4 and D6 RIN prices were around $0.50 per RIN for much of 2019 and 2020, rose to approximately $1.50 per RIN from 2021-2023, before falling back to close to $0.50 per RIN in 2024. We expect that the higher volumes we are finalizing in this rule could result in higher RIN prices, but note that any future projections of RIN prices are highly uncertain, as RIN prices are determined by the marketplace and are impacted by many different factors that we can neither control nor project with confidence, such as crude oil prices and the price of agricultural commodities and market expectations about future standards and other actions. These prices in turn depend on things like the weather, international trade actions, and geopolitical considerations. In this final rule we have analyzed the impact of the proposed volumes on a number of different statutory factors (not just RIN prices) and as discussed in the Preamble Section III, we have determined, based on our analysis of these factors and a review of the implementation of the RFS program to date, that the final volumes are appropriate.

Comment:

A commenter stated that EPA has acknowledged that a healthy RIN bank is necessary to provide liquidity and keep RIN credit prices in check, but the proposed RVO will further drain the already-diminished RIN bank. Another commenter stated that shortfalls in RINS are now occurring, which causes unnecessary price hikes and scarcity.

Response:

In this final rule, as well as previous rules, EPA has acknowledged that a healthy RIN bank helps provide liquidity to the RIN markets and is beneficial to the functioning of the RFS program. However, it is also true that if the RIN bank grows too large the availability of carryover RINs could negatively impact demand for renewable fuels. EPA has reviewed the RIN market and considered the number of carryover RINs projected to be available for use by obligated parties in 2026 and 2027 (see Preamble Section III.F). We find no evidence of the RIN shortfalls or price hikes caused by RIN scarcity described by the commenter. In this final rule we are establishing RVOs based on the volume of renewable fuel we project the market will be able to supply for use as transportation fuel in 2026 and 2027. We are also including an SRE reallocation volume in the applicable volumes for 2026 and 2027 to account for carryover RINs that are attributable to SREs granted for the 2023-2025 compliance years. Notably, in recognition of the importance of carryover RINs to the RFS program the SRE reallocation volume is slightly less than the full number of RINs represented by the SREs granted for the 2023-2025 compliance years.

Comment:

A commenter stated that EPA failed to forecast the impact of their proposal on RIN pricing, despite S&P's prediction that feedstock prices will rise, thereby increasing the cost of renewable fuel production and the RIN price. The commenter argued that rising RIN prices and the loss of the full RIN value for imported feedstocks could jeopardize renewable fuel production, an impact EPA is required to analyze under 42 U.S.C. 7545(o)(2)(B)(ii)(III).

The commenter presented analysis from TM&C that projected RIN prices for EPA's Base Case to converge around $2.89 for all RINs in both 2026 and 2027. The commenter noted that these projected RIN prices were more than four times the RIN prices EPA assumed in its analysis in the DRIA, which was based on outdated data. The commenter stated that the Base Case projects overall compliance costs for 2026 and 2027 to be $67 and $69 billion dollars respectively, the highest since the program's inception.

Another commenter stated that data exists to support more accurate projections for RIN prices than EPA's current assumptions. In particular, the commenter asserted that the break-even RIN value can be easily estimated, particularly for biodiesel and renewable diesel. Using the assumption from the DRIA that the 45Z credit is $0.15 per gallon, the commenter estimated a minimum break-even RIN price of $1.16 per D4 RIN.

The commenter described the equation as providing a floor for the D4 RIN value only, but noted that it is almost double the RIN value assumed by EPA based on the 12-month average. The commenter then stated that, during the time period for which EPA averaged RIN values, even renewable diesel producers showed losses in their renewable segments, which the commenter asserted supports the conclusion that the break-even RIN value must be significantly higher than the average assumed by EPA in Table 10.5.5-1.

The commenter then stated that, because EPA has maintained the 15 billion-gallon implied conventional biofuel (even though it acknowledges that the market cannot blend that much ethanol into gasoline and the gap will have to be filled by the "marginal RIN" from BBD) and the incremental BBD barrel is soy-based renewable diesel, the D6 RIN value will be at parity with the D4 RIN value with a minimum value of $1.16 in this scenario. The commenter concluded that EPA must consider the economics of blending renewable diesel into diesel to calculate a more accurate D4 and D6 RIN value, instead of assuming an average value based on a time period during which renewable diesel producers operated at a loss due to the low RIN value.

Response:

In conducting our analysis for this final rule EPA reviewed the methodologies suggested by this commenter for forecasting RIN prices. Much of the RIN price increase projected by this commenter was a result of the proposed import RIN reduction (IRR) provisions. As we are not finalizing the IRR provisions in this action, we do not expect that the RIN prices projected by the commenter represent an accurate projection of the impacts on RIN prices that will result from this final rule. Further, while analysis by EPA has also found that RIN prices generally follow predictable patterns based on underlying market fundamentals, there is significant uncertainty in projecting the prices of commodities that directly impact RIN prices in future years (crude oil, corn, vegetable oils, etc.). For the analyses in this final rule, we have updated our assessment of the average RIN prices over the past 12 months. This has resulted in a higher estimate of future RIN prices, as requested by the commenters. Finally, while EPA has considered the impact of RIN prices in some of our analyses (*e.g.*, fuel price impacts) we note that on average and at the nationwide scale higher RIN prices do not lead to negative impacts on refiners (see RTC Section 9.1.8).

Comment:

A commenter presented analysis showing that the RIN value for domestic feedstocks could nearly double as a result of the high proposed volumes, no 45Z credit for non-North American feedstocks, and the proposed 50% import RIN reduction. The commenter argued that under these policies, domestic SBO and other U.S. feedstocks become more valuable, leading to a higher RIN price. The commenter expressed concern that on top of the "extraordinarily expensive" 15-billion-gallon implied conventional proposal, the proposed high volumes and 50% import RIN reduction would double the RFS compliance costs for advanced and BBD volumes. The commenter warned that these rising costs could jeopardize some biofuel production capacity, undermining the nation's energy security and independence.

The commenter described that the RIN alone does not enable a biofuel producer to achieve the break-even price, and that Federal tax credits, LCFS credits (notably in California), and other tax credits are stacked on top of the RIN value to close the gap between production cost and competitive sales price. The commenter stated that while the RIN itself was previously feedstock and location neutral, the value of the LCFS credit has always been based on the carbon intensity of the fuel, leading biofuel producers to seek a variety of feedstocks to maximize their LCFS credit value. The commenter argued that the proposed rule could limit renewable fuel producers' ability to optimize feedstocks to support cost-effective production.

The commenter urged EPA to balance its objectives with the reality that the LCFS and 45Z credits add significant value to advanced biofuels made with imported lower carbon intensity feedstocks to ensure the economic feasibility of domestic advanced biofuel production. The commenter reminded EPA of its CAA obligation to analyze the proposal's impact on the rate of commercial renewable fuel production.

Response:

Many of the impacts projected by this commenter are attributable, in whole or in part, to the proposed IRR provisions which we are not finalizing in this action. We recognize that other non-RFS incentive programs such as 45Z and State low carbon fuel standards can have significant impacts on the types of renewable fuels supplied to meet the RFS volume requirements and the RIN prices necessary to incentivize the required volumes of renewable fuel. For this final rule we have updated our analyses of the types of renewable fuels that we project will be supplied to meet the volume requirements to reflect the projected impacts of the 45Z credit. This has resulted in a significant decrease in our projection of the volume of imported renewable fuels as well as a decrease in our projection of imported feedstocks from outside North America. These revised and updated projections are described in Preamble Section III and RIA Chapter 7.

The commenter stated that the proposed rule could result in rising costs that could jeopardize the ability for some renewable fuel producers to operate and this could ultimately lead to a reduction in the operable renewable fuel production capacity. As with the effects discussed above, most of the higher costs the commenter suggests may result in the closing of biofuel production capacity are associated with the proposed IRR provisions, which we are not finalizing in this rule. We note, however, that the RFS operates as a market-based program in which the price of RINs can and do fluctuate based on the level of incentives needed to supply the required volume of biofuel to the markets. The commenter does not describe why the price of RINs would not rise to the level needed to enable biofuel producers to continue production if the current incentives (including the RIN value and other available incentives) were insufficient. We recognize that individual biofuel producers may cease production in response to changing market conditions and increased competition. However, given the market-based nature of the RFS program, it is extremely unlikely that total U.S. biofuel production capacity and renewable fuel production would decrease in response to higher volume requirements.

Comment:

A commenter asserted that due to the fuel blends that most cars and trucks are equipped to handle and the demand projections for gasoline, the result of the proposed rule would not be increased ethanol blending, but instead an increase in RIN prices.

Response:

In this final rule, we have updated our projection of ethanol consumption, including our projection of higher-level ethanol blends. Contrary to the commenter's statements, available data suggest that ethanol consumption is not currently limited by the number of vehicles that are able to operate on higher level ethanol blends. Instead, we project that ethanol consumption in 2026 and 2027 will continue to be limited by the relatively small number of retail stations that offer higher level ethanol blends and relatively low sales volumes of these fuels as retail stations that offer them. Our projections suggest that the volumes we are finalizing in this rule will result in an increase in total ethanol consumption, as these volumes provide continued incentives for investment in the infrastructure needed to offer higher level ethanol blends at retail stations and ongoing support for the sale of these blends. Nevertheless, as in past years, we project that total ethanol consumption will fall short of the implied conventional renewable fuel volume of 15 billion gallons, and that additional volumes of non-ethanol fuel such as biodiesel and renewable diesel will be needed to meet this shortfall. The renewable fuel volumes in this final rule account for the projected shortfall in ethanol consumption relative to the implied 15-billion-gallon conventional renewable fuel volume.

Comment:

A commenter discussed EPAs analysis of the "No RFS" Baseline in the DRIA to estimate whether the increased D6 RIN prices attributable to proposed RIN reductions for imports is sufficient to incentivize additional investment in E85 and E15 retail sites. The commenter estimated an increase in D6 RIN prices from the $0.80 per RIN average for the first half of 2025 to $1.70 per RIN in 2026 and 2027. A $1.69 D6 RIN price corresponds to $1.26 per gallon of E85 (based on the average 74% ethanol content assumed by EPA). The commenter noted that EPA estimates a retail cost of $0.15 per gallon of ethanol to install new E85 stations and a need to price retail E85 16% lower than E10. As the "No RFS" scenario does not benefit from any RIN value, EPA concludes that new E85 installations are noneconomic in most of the U.S. in the absence of the RFS program. For their analysis with the proposed RVOs, EPA assumes that E85 installations grow only at the historic rate, ignoring the increased economic incentives created by the proposed import RIN reductions and elimination of the 45Z credit-eligibility for imports, as well as the RFS program's power to incentivize additional infrastructure expansion.

The commenter argued that incorporation of their estimated $1.69 D6 RIN price exceeds the required E85 Ethanol Cost Difference, including consideration of EPA's estimated $50,300 cost per station, and thus would be more than sufficient to accelerate additional investment in E85 in most of the United States.

Regarding E15, the commenter noted that EPA estimates an average cost of $133,000 per station to add E15 to a retail station, far higher than their estimate of $50,300 to add E85 to a retail station. Due to the lower ethanol content of E15 relative to E85, that cost amounts to far more per incremental gallon of ethanol dispensed. This cost is partially offset by E15 only requiring an estimated 1% price discount versus E10 and the fact that all 2001 model year and newer light-duty vehicles can use E15. The commenter criticized EPA's use of a single, average installation cost estimate as misleading, since per-station costs have been found to vary significantly due to site-specific issues. The commenter suggested that EPA could produce a more accurate assessment by using two or more cost estimates, better representative of this range, which may reveal that there is a significant fraction of retail sites for which E15 installation is indeed economic. The commenter stated that their estimated $1.69 D6 RIN price would be sufficient to accelerate additional investment in E15 in the average U.S. market if Higher Blends Infrastructure Incentive Program funding for one-half of the infrastructure cost were available. However, the $1.69 D6 RIN would not be sufficient in the highest cost U.S. markets.

The commenter added that for both E15 and E85, inclusion of potential tariff impacts on RIN prices would make economics for E15 and E85 investments even more favorable.

Response:

As discussed in greater detail in Preamble Section III, we expect that this final rule will continue to provide significant incentives for the investment in the infrastructure needed to offer higher level ethanol blends such as E15 and E85 at retail. In this final rule we have projected growth in the number of retail stations offering E15 and E85 based on the observed growth rate from previous years. We believe this is appropriate because the growth rate in the number of stations in previous years also reflects the impacts of the incentives offered by RINs, as well as other available incentives such as HBIIP.

We recognize that it is possible that the changes to the available incentive programs mentioned by the commenter (the potential for higher RIN values and changes to the 45Z credit to extend this credit to ethanol and disqualify imported biofuels) may increase the rate of growth in the number of retail stations offering higher level ethanol blends. At this time, we do not have sufficient data to project an alternative rate of growth based on higher incentives. We note that these infrastructure projects often take extended period (months to years) to complete, so any investments made in response to this final rule would likely have a limited impact on ethanol consumption in 2026 and 2027. We will continue to monitor the rate of growth in the number of stations offering higher level ethanol blends and may consider alternative projection methodologies in future years if the available data indicate changes are warranted.

The comments on the infrastructure costs of E15 are discussed in RTC Section 9.1.1.

Comment:

A commenter concluded that the proposed changes relating to imported feedstocks, together with the changes to the 45Z credit, would appear to benefit corn ethanol in terms of its competitiveness versus biodiesel in the D6 RVO category. This would be in terms of both increasing potential throughput at existing E15 and E85 retailers as well as accelerating investments in new retail sites. The commenter argued that the corresponding D6 RIN uplift would appear to be more than sufficient to enable E85 to be discounted by 21% or more versus E10 (energy-parity pricing) and incentivize additional investment in E85 retail infrastructure.

Response:

Comments on the potential impact of the RFS incentives and the 45Z credit are discussed in the previous response.

We also recognize that the potential for higher RIN values and changes to the 45Z credit to extend this credit to ethanol and disqualify imported biofuels could result in lower prices for E85 at retail relative to E10. These lower prices could result in increased sales of E85, and ultimately higher ethanol consumption than we have projected in this rule. These changes are not certain, however. Notable, because relatively few retail stations offer E85 the limited competition among retailers often results in the incomplete passthrough of incentives such as the RIN value and 45Z credit to retail prices. Further, prior analysis of the impacts of E85 retail price discounts relative to E10 determined that sales volumes only increase moderately as that discount increases.[174]

Finally, we note that the volumes we are finalizing in this rule provide a significant opportunity for increasing sales of E15 and E85. In our technical analysis for this rule, we project the total supply of conventional renewable fuel will be approximately 14.2-14.3 billion gallons in 2026 and 2027. This is approximately 700-800 million gallons less than the implied conventional renewable fuel volume for these years. EPA projected that total ethanol consumption in higher level ethanol blends would be approximately 500 million gallons in 2026 and 2027. Thus, even if the market supplied twice the volumes of E15 and E85 projected by EPA the volumes we are

[174] "Comparison of D6 RIN Prices, the Price of Ethanol Relative to Gasoline, and Higher-Level Ethanol Blend Sales," available in the docket for this action.

finalizing in this rule would still provide an opportunity for these fuels to compete with other non-ethanol biofuels to meet the implied conventional biofuel volumes for 2026 and 2027.

Comment:

A commenter identified a few specific revisions/clarifications needed in the DRIA:

- EPA states: "[w]hen crude oil prices increase, both renewable fuel feedstock prices and gasoline and diesel prices tend to increase as well, although gasoline and diesel prices generally increase more relative to renewable fuel feedstock prices." Yet, Figure 1.1.1-1 actually counters this statement, as corn and soy prices decrease as crude increases.
- Whether or not the fuel is "competitive" does not matter when EPA requires retirement of RINs by a small refinery. Therefore, the cost of the RIN is a more meaningful comparison to crude price than "competitiveness." RIN prices do not correlate to crude cost, or any feedstock cost for that matter. RIN costs are volatile and can change on rumor, RVOs, and feedstock prices. The nice smooth relationship presented in Section 1.1.1 of the DRIA is actually false (as projections are inherently unstable and are often more reactive to short term variables, like drought and tariffs) and has no impact on what actual steps and burdens a small refinery must take to comply.
- In Chapter 1.7.1 of the DRIA, EPA states that D4 RINs are "generally sold together with the renewable fuel to refiners or blenders."
    - This statement is inaccurate. D4 RINs are sold separately, and all D3 and D5 RINs are sold separately. Only D6 RINs are occasionally sold with ethanol, but many D6 RINs are sold outside of an ethanol sale.

Response:

Contrary to the commenter's statements, the historic data presented in Figure 1.1.1-1 does indicate that from 2022–2025 (the only historic years presented) crude oil, corn, and soybean oil prices all decreased. Thus, EPA's statement in the RIA noting that the prices for these three commodities have generally increased or decreased together is supported by the available data, despite the fact that USDA projects slight crude oil increases and slight soybean oil decreases in future years.

We recognize that because the RFS volume requirements are mandates, obligated parties must comply with the volume obligations (or take advantage of the flexibilities offered in the RFS program such as the use of carryover RINs or deficit carry forward provisions) regardless of whether or not renewable fuels are competitive with petroleum-based fuels. Nevertheless, the general statement that higher crude oil prices generally make renewable fuels more economically competitive with petroleum-based fuels is an accurate description of the underlying economic fundamentals. We also recognize that the relatively smooth prices for commodities in future projections rarely, if ever, occur in the market due to a number of unforeseen factors. We still believe these projections are informative of likely future market conditions and represent the best available information at this time.

Finally, we are aware that the markets for RINs and renewable fuels have become increasingly complex, and that significant volumes of RINs are sold separately from, rather than attached to, renewable fuel. We have updated this text to reflect this reality.

Comment:

A commenter stated that the proposal has and will increase feedstock, RIN, and RFS compliance costs, and by increasing the cost of biofuel production and relying on advanced volumes to fulfill an unachievable ethanol mandate, RIN prices for the entire conventional mandate will need to increase to ensure advanced biofuel production is economical.

Response:

We recognize that the renewable fuel volume requirements for 2026 and 2027 will likely increase prices for feedstocks and renewable fuels. RIN prices, however, are difficult to project as they can fluctuate based on a wide range of factors beyond simply the prices for renewable fuels and renewable fuel feedstocks. We do, however, expect that D6 RIN prices will be higher in 2026 and 2027 than they would otherwise be if the implied conventional renewable fuel volume requirements for 2026 and 2027 were at or below the E10 blendwall.

EPA has considered the potential impacts of this rule on agricultural commodity prices and the cost of transportation fuel to consumers, among other factors. Our analyses are summarized in Preamble Section III and presented in greater detail in the RIA. Based on our review of the implementation of the RFS program to date and the statutory factors, we have determined that the volume requirements we are finalizing in this action are appropriate.

9.1.4 Impacts of Standards on Retail Fuel Prices

Comment:

A commenter stated that EPA's assessment of fuel costs and costs to transport goods was inadequate. The commenter noted that EPA estimated costs to transport goods for the proposed volumes as a whole, but this limited analysis did not accurately depict the difference between the biodiesel market and the renewable diesel and jet fuel markets.

Response:

EPA's projection of the impact of this final rule on fuel costs and the cost to transport goods does consider the differences between biodiesel and renewable diesel. For example, our projections of the fuel costs of the final rule separately estimate the cost of production of biodiesel and renewable diesel in light of the differences in the production processes for these fuels. Our estimate of the No RFS baseline (the primary baseline for our analyses in this rule) considers the differences in the blending rates between biodiesel and renewable diesel at the retail level, and how the differences between these fuels impact the quantity of each fuel that can be used in markets with higher non-RFS incentives, such as California. Our projections of the impact of this rule on fuel prices and the cost to transport goods are based on the estimate of the impacts of the rule on fuel costs, as well as the impacts of available non-RFS incentives and RIN prices, and therefore also take into account the differences between these fuels.

Comment:

A commenter argued that the RFS program, when implemented properly, has proven to be an effective, market-based program that diversifies, enhances, and improves the emissions characteristics of the nation's fuel supply while lowering costs for consumers. The commenter stated that given the central importance of trucking and diesel fuel in the nation's supply chain for goods, low-cost biodiesel not only makes fuel cheaper for fleets and truck drivers but subsequently lowers shipping costs and thus makes all goods more affordable. The commenter expressed concern that without biodiesel, these dynamics in the BBD market would likely change to the detriment of consumers.

A few commenters provided general comments that increasing production of renewable fuel lowers diesel fuel prices.

Response:

Many of these conclusions are consistent with EPA's analysis. The RFS program has contributed to the diversification of the transportation fuel supply in the U.S. and has increased U.S. energy security. We estimate that the increase in the production and use of renewable fuels has the potential for overall GHG emissions from the transportation sector. However, our analysis in this final rule, as well as in previous RFS rules, indicates that requiring higher volumes of BBD and other advanced fuels increases, rather than decreases, the cost of transportation fuel. For example, in the RIA for this final rule we project that the cost of biodiesel will be $1.03–$1.95

per gallon more expensive than diesel fuel in 2026 and 2027 and renewable diesel will be $1.23–$2.15 per gallon more expensive than diesel fuel. These costs do not include a consideration of the federal tax credits or other available State incentives that reduce the price of these fuels to consumers. Nevertheless, after accounting for all the available incentives and the projected impact of RINs on retail fuel prices we project that the volumes we are finalizing will increase the retail price of diesel fuel by approximately $0.20 per gallon. We recognize that biodiesel and renewable diesel blends can be, and often are, offered at lower prices than petroleum diesel at retail stations. This comparison ignores both the increase in the retail price of petroleum diesel due to the RIN obligations for this fuel and the decrease in the retail prices of biodiesel and renewable diesel blends enabled by the RIN value.

Comment:

Many commenters generally stated that the proposed rule would increase transportation or energy costs for Americans, including families and small businesses. A commenter stated that the proposed volumes would impose significant costs to consumers, increasing fuel prices by $13.43 billion over the two years of the rule. The commenter argued that while EPA attempts to minimize these fuel costs by presenting them on a per consumer and per gallon scale, the total economic impacts are enormous when aggregated and will only add to the distress of Americans already struggling with inflation.

Response:

We recognize that the volumes we are finalizing in this rule are likely to result in increased fuel costs for consumers. EPA has updated our estimates of the impact of this rule on fuel costs and retail fuel prices for this final rule. These analyses can be found in RIA Chapter 10. EPA's justification for the volumes in this final rule, despite the relatively high costs of the rule, can be found in Preamble Section III.

Comment:

A few commenters stated that studies show that drivers are paying up to 30 cents per gallon as a result of the RFS program and the financial burden imposed by the compliance costs to purchase RINs. Many other commenters stated that the RFS program raises fuel costs by approximately 20–30¢ per gallon. One commenter noted that higher fuel costs caused by a broken RFS system, or in a worst case, caused by regional refinery closures, would have devastating effects on communities, residents, and businesses in tourist, healthcare, and retail hubs that require visitors to drive to those destinations.

Response:

These comments appear to be considering only the impact of the cost of RINs on petroleum-based fuels. As discussed in RIA Chapter 10.5, we estimate that the cost of RINs to obligated parties for compliance with the 2026 and 2027 standards is approximately $0.16 per gallon of petroleum fuel based on the RIN prices in 2025. These costs could be higher if RIN prices rise in 2026 and 2027. However, this is neither the impact of RINs on fuel prices nor the impact of the

2026 and 2027 standards on fuel prices as it ignores the subsidy that RINs provide (*e.g.*, the RIN discount) to the renewable fuels that are blended into the vast majority of transportation fuel sold in the U.S. The RIN functions as a cross subsidy, reducing the cost of renewable fuels such as biodiesel while increasing the cost of petroleum fuels into which they are blended. Therefore, with the exception of RINs generated for fuels that are not blended into gasoline and diesel, RINs generally do not increase or decrease the price of transportation fuel. The estimates of the impact of the RFS volumes we are finalizing in this rule are discussed in RIA Chapter 10.5. Our estimates of the impact of this rule on fuel prices are roughly 5¢/gal for gasoline and 20¢/gal for diesel fuel in 2026 and 2027 period. We note that these price impacts include the additional costs of producing renewable fuels and are not simply the impacts of RIN prices on the price of gasoline and diesel.

Comment:

A commenter explained that the costs of policies, including the RFS program, supporting bio-based diesel is considerable, noting a study that found that bio-based diesel prices (not counting direct and indirect subsidies) tend to be about double those of fossil diesel, a difference of about $2 per gallon, which must be made up by policy. The commenter noted that there are a number of different policies that determine how these costs are distributed to different parties. However, the commenter stated that, generally, costs are borne by people buying gasoline and diesel and taxpayers that bear the cost of tax credits.

Response:

We recognize that the volumes we are finalizing in this rule are likely to result in increased fuel costs for consumers. EPA has updated our estimates of the impact of this rule on fuel costs and retail fuel prices for this final rule. In the RIA for this final rule we project that the cost of biodiesel will be $1.03–$1.95 per gallon more expensive than diesel fuel in 2026 and 2027 and renewable diesel will be $1.23–$2.15 per gallon more expensive than diesel fuel. Our analyses of the fuel costs and the fuel price impacts (which include the policies that can effect how these costs are distributed to different parties) can be found in RIA Chapter 10. EPA's justification for the volumes in this final rule, despite the relatively high costs of the rule, can be found in Preamble Section III.

Comment:

A commenter urged EPA to carefully consider how reduced incentives for imported biofuels may impact fuel pricing and accessibility in Tribal and rural communities, particularly in areas where distribution networks are limited and fuel costs are already elevated.

Response:

EPA has not finalized the proposed IRR provisions in this action. We intend to finalize these provisions in a future action, and anticipate that the delay in finalizing these provisions will allow the market more time to anticipate and make adjustments to account for these changes to minimize the potential price impacts raised by this commenter.

Comment:

A commenter asserted that EPA violated its statutory obligation to consider the impact of the use of renewable fuels on the "cost to consumers of transportation fuel and on the cost to transport goods," by excluding the impact on wholesale gasoline and diesel prices from its analysis of the "No RFS" baseline. The commenter stated that analysis of the cost of fuels under the No RFS scenario would have shown that the difference in fuel cost to a "No RFS" baseline scenario is even higher than reported.

Response:

EPA has not excluded the impact of the RFS program in our consideration of the cost to consumers of transportation fuel and on the cost to transport goods. As stated in RIA Chapter 1, EIA generally includes a consideration of current regulations in their modeling. Thus, it is reasonable to expect that their projections in the AEO2025 contain some assumptions about the RFS program in future years. However, it is not readily apparent what these assumptions are, nor how they impact the projected prices of gasoline and diesel in 2026 and 2027. In our estimates of the impact of the cost to consumers of transportation fuel (and in our projections of the cost to transport goods, which are based on the projected costs of transportation fuel) we have assumed that the wholesale prices of gasoline and diesel reported in AEO2025 do not consider the cost of meeting RIN obligations. To account for these costs, we add these costs to the projected AEO2025 prices for petroleum-based gasoline and diesel when estimating fuel prices in 2026 and 2027 with the renewable fuel volume requirements. While we have not subtracted the estimated price impacts of the RFS obligations from the gasoline and diesel prices in the AEO2025 for the No RFS baseline case, we have added these costs to the projected gasoline and diesel prices when estimating the price impacts of this final rule and have therefore appropriately considered these costs. More information on our projections of the impacts of this final rule on the cost to consumers of transportation fuel and the cost to transport goods can be found in RIA Chapter 10.5.

Comment:

A commenter questioned EPA's analysis of the impact of Renewable Natural Gas (RNG) on fuel costs. The commenter noted that EPA contended that "the combination of high RIN prices and the growing volume of CNG/LNG used as transportation fuel and the high cellulosic RIN prices that refiners must recover through fuel sales leads to an expected increase in gasoline and diesel prices." The commenter found it unclear why EPA compared RNG to natural gas when discussing benefits, but then looked at gasoline and diesel fuel prices to assess potential costs. The commenter argued that EPA provided no evidence that refiners "must recover" D3 RIN costs through fuel sales of gasoline and diesel, noting that several obligated parties had invested in RNG facilities and thus generate RINs through those investments. The commenter also pointed out that EPA found that per unit costs of natural gas decreased based on the proposed volumes. The commenter stated that when considering the cost to transport goods, EPA ignored its own determination about decreased natural gas costs, claiming that most goods being transported utilize diesel fuel power trucks, and thus focused on diesel price impacts. The commenter argued that this assessment was problematic because many fleets that transport goods were looking at increasing the use of natural gas vehicles and using RNG to power those vehicles. The commenter also discussed that EPA's analysis of RNG costs focuses on landfill projects, which may not be representative of the industry as a whole.

Response:

The commenter appears to be conflating EPA's assessments of the cost and benefits using RNG as CNG/LNG as transportation fuel and the price impacts of the cellulosic biofuel volume requirements. For our analysis of most of the statutory factors EPA has assessed the impact of displacing fossil natural gas with RNG. This is because we project that the vast majority of the RNG used as transportation fuel will be used by existing (rather than new) vehicles. In the absence of the RFS volume requirements we project that many of these vehicles would use fossil natural gas rather than RNG. Thus, the impact of the cellulosic biofuel standard is to primarily incentive the use of RNG in place of fossil natural gas.

The situation is different, however, when assessing the likely impact of the standards on the price of transportation fuel. The RFS program places obligations on refiners and importers of gasoline and diesel; no obligations are placed on producers or importers of natural gas. These obligated parties comply with their RFS obligations by acquiring RINs. Analyses by EPA and others has repeatedly demonstrated that obligated parties pass the cost of these RINs (including the cellulosic RINs) to consumers in the price of the gasoline and diesel fuel they produce.[175] And because RNG is not blended into gasoline and diesel (like ethanol, biodiesel, and renewable diesel) these RIN costs are not off-set in whole or in part by discounted prices for renewable fuel that is blended into gasoline and diesel. The structure of the RFS program thus shifts the cost of the incentives for increased production and use of RNG to the gasoline and diesel pools.

We are aware that some obligated parties have invested in RNG production, and in some cases may therefore be able to acquire cellulosic RINs at a lower price than by purchasing separated RINs. Using RINs from the RNG they produce, however, results in an opportunity cost (vs. selling these RINs to other parties), and it is unclear how these opportunity costs are considered by different obligated parties. Further, few obligated parties have sufficient investments in RNG to provide all the cellulosic RINs they need for compliance. To the extent that it is more expensive to purchase cellulosic RINs than to acquire cellulosic RINs by producing RNG we would expect these higher marginal costs to set the market price for gasoline and diesel.

Finally, while it is accurate that RNG is used to transport some goods, and that interest in CNG/LNG vehicles may be increasing currently the vast majority of goods are transported via trucks with diesel engines. This situation will not appreciably change through 2027. Therefore,

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[175] 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 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.

EPA's decision to consider only diesel prices in our assessment of the cost to transport good in this final rule is reasonable.

Comment:

A commenter criticized EPA's analysis with respect to the impact of higher cellulosic biofuels on cost to consumers of transportation fuel and on the cost to transport goods as limited. The commenter noted that EPA's analysis makes simplifying assumptions that ignore the use of virtual pipelines to connect projects to commercial pipelines. The commenter explained that virtual pipelines (*e.g.*, using trucks to deliver RNG to the commercial pipeline interconnection) were often used with respect to agricultural projects that EPA claimed "could be considered stranded and not readily available for use as transportation fuel." Despite these limitations, the commenter pointed out that EPA's costs estimates showed that RNG had the lowest production cost per gallon and lower total costs than all other biofuels analyzed by EPA, and these costs were also less than that for gasoline and diesel fuel. The commenter noted that although EPA claimed that the total net costs of RNG was higher than natural gas, EPA nonetheless found a decrease in net costs when looking at the proposed volume requirements.

Response:

The commenter accurately states that in EPA's fuel cost analysis, EPA made the simplifying assumptions that RNG is sourced from landfills and is delivered via direct pipeline connections (rather than via virtual pipelines). Based on the data available to EPA, the majority of RNG currently used as transportation fuel is sourced from landfills that deliver RNG via pipeline. Further, while differences in the size of landfills producing RNG and the quality of the biogas they recover which impact the cost of RNG production, these facilities have enough similarities to enable EPA to produce representative cost estimates. Conversely, for non-landfill RNG sources there is significant variation in the size, technologies used, and other factors such that estimating a representative cost is not viable. Similarly, differences in the size of RNG producers and the distance between these facilities and pipeline injection points makes any estimate of the cost of delivering RNG via virtual pipeline highly uncertain. Finally, we note that the volumes of RNG we have projected in the volume requirements for 2026 and 2027 have not been directly impacted by the projected supply of RNG nor by the projected cost of RNG. Instead, the volumes are based on our projection of the quantity of CNG/LNG that can be used as transportation fuel in 2026 and 2027. Therefore, even if EPA had considered that greater volumes of RNG could be supplied at lower cost than we have projected in this rule from non-landfill facilities using virtual pipelines these facts would not have impacted the final volumes of cellulosic biofuel for 2026 and 2027.

Comment:

A commenter noted that unlike for the projected cellulosic biofuel volumes for 2023-2025, EPA did not appear to break out the expected $0.01-$0.02 per gallon increase in diesel and gasoline prices that it previously inferred (with no support) in this proposed rule. Although the volumes EPA proposed for 2026 and 2027 are comparable to the 2023-2025 volumes, the commenter pointed out that EPA did not provide any analysis as to whether it was correct in its prediction regarding fuel prices.

The commenter provided market data showing that at the time of EPA's proposal for 2023-2025, gasoline and diesel fuel retail prices averaged $3.444 and $4.539, respectively. For the week ending July 21, 2025, gasoline and diesel fuel prices were below these prices, according to EIA. The commenter noted that for gasoline, retail prices averaged $3.123 for the week ending July 28, 2025, and for on-highway diesel fuel, prices averaged $3.805 for the week ending July 28, 2025. The commenter argued that EPA could not tie fuel prices to D3 RIN prices because numerous factors play into fuel prices, and even if there was a $0.01-$0.02 cent increase, it would be about 0.3–0.6% per gallon.

Response:

In this final rule, EPA did project the impact of the cellulosic biofuel volume requirement on gasoline and diesel prices (see RIA Chapter 1.7). We projected this impact would be about $0.015 per gallon in 2026 and 2027. Given the relatively small magnitude of these impacts (as noted by the commenter) and the wide range of non-RFS factors that impact gasoline prices it is difficult for EPA to observe whether these projected price impacts were realized in 2023-2025. However, analysis by EPA and others has repeatedly demonstrated that obligated parties pass the cost of these RINs (including cellulosic RINs) to consumers in the price of the gasoline and diesel fuel they produce.[176] Further, even if EPA had not considered the potential price impacts on gasoline and diesel this would not have impacted the final volumes of cellulosic biofuel for 2026 and 2027, which are primarily a factor of the quantity of CNG/LNG that we project can be consumed as transportation fuel in 2026 and 2027.

Comment:

A commenter also noted that while EPA appeared to try to engage in a cost-benefit analysis considering fuel costs and energy security benefits, EPA did not attempt to quantify many of the benefits of cellulosic biofuel, including the public health benefits, and Congress did not require a cost-benefit analysis. The commenter concluded that it was clear that the benefits of RNG far outweighed the potential minimal increases in fuel costs.

Response:

As stated in the RIA Executive Summary, not all of the expected impacts of this final rule were able to be quantified or monetized. Further, some of the impacts that were quantified and/or monetized do not represent societal costs or benefits. Where possible we have attempted to quantify the expected impacts of this rule, however we note that an inability to provide a quantified estimate of the impact for any of the statutory factors does not indicate that this factors was not considered by EPA when determining the appropriate volumes for 2026 and 2027. See the RIA Executive Summary for a summary of the quantified and unquantified impacts of the

[176] Id.

rule. Preamble Section III provides a description of EPA's consideration of all the statutory factors to determine the renewable fuel volumes in the final rule.

Comment:

A commenter stated that bioethanol frequently provides a lower-cost alternative to petroleum-based gasoline, exerting downward pressure on consumer fuel prices and reducing fuel cost volatility. The commenter also stated that increased use of bioethanol blends, including E15 and E85, directly lowers consumer transportation costs and ultimately benefits overall household budgets and economic stability.

Response:

EPA's analysis is consistent with the commenter's statements that ethanol is often available at a lower cost than gasoline on a per gallon basis. Whether this lower cost availability translates to lower transportation costs for consumers is complicated by many factors, including the lower energy content of ethanol relative to gasoline, the high-octane value of ethanol, and the infrastructure costs associated with selling fuel containing greater than 10% ethanol. EPA's market analysis indicates that after accounting for all these factors ethanol sold in E10 blends generally reduces the cost of fuel for consumers, while ethanol sold in higher level ethanol blends (such as E15 or E85) generally increases costs for consumers. This is true even in cases when these fuels are offered at a lower price per gallon than E10 due to the lower energy content of these fuels relative to E10 and the RIN price impact on all petroleum-based gasoline and diesel. Nevertheless, we expect that there is significant potential for ethanol to provide even greater incentives in the future, especially if the number of retail stations offering higher level ethanol blends continues to increase and petroleum blendstocks are developed for higher level ethanol blends that take advantage of the high octane rating of ethanol. By maintaining the implied 15-billion-gallon volume for conventional renewable fuel in 2026 and 2027, we are providing opportunity for increasing volumes of ethanol to compete for market share in the total renewable fuel category.

9.1.5 Price and Supply Impacts on Food and Agricultural Commodities

Comment:

Multiple commenters discussed that the RFS program stabilizes regional commodity markets and farm income by supporting price stability, jobs, and rural economies. They viewed EPA's analysis as sound and expect the proposed BBD and conventional volumes to boost demand for domestic feedstocks and biofuels, maintain stable prices, spur investment, and broadly benefit consumers, with only minimal effects on agricultural and food prices since increased supply would meet the added demand.

Response:

We appreciate the commenters' views on the RFS program's role in stabilizing regional commodity markets and supporting rural economies. Since the Set 2 proposal, EPA has updated its analysis on commodity supply and pricing in RIA Chapters 9.2 and 9.3. We have also updated our assessment of impacts on rural economies, which we discuss in RTC Section 9.1.6 and in RIA Chapter 9.1, and we have updated our analysis of impacts on food prices in RIA Chapter 9.4. Based on this updated analysis, we find that the volume requirements finalized in this action will strengthen the RFS program, boost renewable fuel use, and provide strong support to domestic feedstock producers, renewable fuel producers, and agricultural communities across the country.

Comment:

A commenter argued that historical data show no correlation between corn prices, food prices, or corn acreage and RFS volumes or ethanol production. Using USDA, EIA, and BLS data through 2024, they found food and overall inflation moved together and spiked in 2021 and 2022 without linkage to ethanol; their analysis indicated the RFS did not materially expand corn acreage, and after holding 2007 acreage constant, scaling non-ethanol uses with population, and accounting for yield and ethanol plant efficiency gains, they concluded the RFS is not a driver of food price inflation, which instead reflects broader costs and factors such as energy, labor, capital, regulation, dietary preferences, and weather.

A commenter argued that EPA's estimate that the proposed standards will raise the price of corn by $0.03 per bushel, assuming that corn prices rise by 3% per billion gallons of ethanol, is greatly overstated. The commenter asserted that EPA's projected ethanol volumes can be achieved without diverting corn from non-fuel uses and therefore will have no effect on corn prices. The commenter identified several issues with EPA's analysis:

1. The 2015 and 2016 studies supporting the 3% price increase effect are outdated and fail to account for significant increases in per-acre yields of corn and per-bushel yields of ethanol since 2015 and corresponding decreases in the amount of land, a primary input cost for production, required to produce one billion gallons of ethanol.
2. The 3% factor is correct only if the incremental RFS volume results in an equal increase in U.S. ethanol production. The commenter noted that it is likely that increased domestic

demand for ethanol would likely come from reduced exports rather than increased domestic production.

3. EPA fails to provide context on the significance of such a change in corn price, including accounting for the 28% annual standard deviation in corn prices due to all factors calculated using monthly data on corn grain prices from January 2007 through May 2025.

The commenter also stated that EPA appropriately adjusts for estimated future impacts of inflation and crude oil prices on corn prices but could produce a more consistent estimate of future Dried Distillers Grains with Solubles prices by applying Missouri-FAPRI's correlation between corn and Dried Distillers Grains with Solubles prices to EPA's estimate of future corn prices.

Response:

In RIA Chapter 9, EPA estimates food price impacts using a no-RFS baseline that isolates ethanol's effect on corn prices. Based on the published literature, we assume corn prices increase by about 3% for each additional billion gallons of ethanol (see RIA Chapter 9.4). We also acknowledge (RIA Chapter 9.2) that some ethanol production may come from sources that do not require new cropland, and we evaluate the amount of corn cropland potentially attributable to the RFS. Therefore, while ethanol volumes may not fully drive planting decisions, they can still influence prices. Overall, we estimate the 2026 and 2027 volumes would lead to a slight increase in food prices.

In response to the specific items raised by the commentor:

1. As discussed in RIA Chapter 9.3, crop prices are shaped by many factors, including global weather patterns, energy costs, biofuel policies, and international tariffs and trade disputes. While we acknowledge significant improvements in per-acre corn yields and ethanol conversion efficiency since 2015, the studies underpinning our corn price estimates remain, in our judgment, the best available analysis at this time.

2. We recognize the commenter may be correct, and we acknowledge this in RIA Chapter 9.3. In recent years, U.S. ethanol production has exceeded domestic consumption, with substantial exports, and this pattern is likely to continue in 2026 to 2027 because projected consumption remains below USDA's projected production. This export history complicates predictions of commodity price impacts. If higher domestic ethanol use is mostly offset by lower exports, domestic production may change little. Likewise, if the RFS volume standards do not meaningfully change total domestic corn demand, corn prices are unlikely to change much. Alternatively, lower U.S. net corn exports could reduce supply to international markets and put upward pressure on global corn prices. It is also possible (though less likely) that an increase in consumption would result in an increase in domestic corn ethanol production. In this case we would expect a correlated change in corn demand and corn prices. In all cases, we rely on the best available literature, which indicates that each additional billion gallons of ethanol is associated with roughly a 3% increase in corn prices.

3. We agree with the commenter that the 3% per billion-gallon factor is small relative to the annual standard deviation of corn prices and to ethanol prices.

Finally, we appreciate the commenter's statement that our sources are appropriate for this analysis. We also acknowledge the suggestion to improve consistency in projected DDGS prices by applying Missouri FAPRI's estimated correlation between corn and DDGS prices to our corn price forecast. We will consider this refinement in future updates, but we believe our current approach is appropriate for this analysis.

Comment:

Another commenter requested that EPA adjust the proposal to avoid negative impacts on Americans' health through impacts to food prices. The commenter suggested that at minimum, EPA should drastically reduce the RIN value for tallow compared to other cooking oils and renewable fuels because it presents a healthier alternative to seed oils.

Response:

This rule does not finalize the proposed import RIN provisions, so they are not included in our analysis of how the final volumes affect the statutory factors. We appreciate the commenter's request to adjust the proposal to avoid potential adverse effects on Americans' health through food prices. EPA does not set RIN prices; they are determined by the market and are not administratively differentiated by feedstock.

Comment:

Commenters said vegetable oils are not a suitable substitute for animal fats in pet food manufacturing. Because the pet food industry depends on animal fats, it competes directly with BBD producers, which are incentivized to use animal fats due to their low carbon intensity. Pet food producers also cannot rely on imported animal fats because of food safety concerns, so Federal and State policies that encourage animal fat use in biofuel further strain a limited domestic supply. Commenters also noted that the use of animal fats in BBD has grown sharply over recent years, while domestic production of animal fats has expanded only modestly. This imbalance, rapidly increasing demand against limited supply growth, intensifies price pressures felt by pet food makers.

Response:

This rule does not finalize the proposed import RIN provisions. Therefore, those provisions are not expected to increase reliance on imported animal fats to the degree the commenter raised, including with respect to food safety concerns. We agree that the volumes finalized in this rulemaking could affect agricultural commodity prices, as described in RIA Chapter 9.3. However, under section 211(o)(2)(B)(ii) of the Clean Air Act, Congress directed EPA to consider a set of factors without prescribing specific analytical steps or how to weigh each factor. We believe we have appropriately considered potential food price impacts, as well as the price and supply of edible oils, within the full set of statutory factors in establishing these standards.

Comment:

A commenter stated that EPA's cost analysis fails to meet applicable legal standards and underestimates impacts to food and agricultural commodities prices. In particular, the commenter discussed that EPA unreasonably and insufficiently shifts projections in the use of feedstocks from non-biofuel markets to biofuel markets.

Response:

The commenter does not identify any specific deficiencies in EPA's examination of food and agricultural commodity supply and price impacts; rather they argue that such an examination should be part of a more comprehensive economic analysis. However, the commenter does not identify any analytical methodologies that they believe would be appropriate for such an analysis, nor do they explain why such an analysis would provide more robust results than that which we included in the DRIA. Since the Set 2 proposal, EPA has updated its analysis on commodity supply and pricing in RIA Chapters 9.2 and 9.3. We have also updated our assessment of impacts on rural economies, which we discuss further in RTC Section 9.1.6 and in RIA Chapter 9.1, and we have updated our analysis of impacts on food prices in RIA Chapter 9.4. Based on this updated analysis, we find that the volume requirements finalized in this action will strengthen the RFS program, boost renewable fuel use, and provide strong support to domestic feedstock producers, renewable fuel producers, and agricultural communities across the country. Absent any suggested alternative methodological suggestions from the commenter, it is not possible for us to know what they would have preferred to see, or whether their preferred analysis would be more robust than what we have included in the RIA. Lacking any such specific information to the contrary, we believe the analysis we have conducted is sufficiently robust to meet the statutory requirements. In summary, we believe we have appropriately considered food prices impacts, as well as the price and supply of edible oils, in the context of all the statutory factors in establishing the standards.

Comment:

Commenters argue the RFS is increasing overall costs and contributing to higher food prices. They say EPA's own projections show food expenditure increases but believe the real impact will be larger due to higher BBD obligations, proposed changes affecting import credits, and a lag in expanding soybean processing capacity. EPA's modeling is cited as indicating notable food and feed price increases for most directly affected commodities, with limited exceptions for certain livestock feed co-products.

They highlight feedstock competition as a key driver: a large share of corn and soy is already used for fuel, and demand that exceeds domestic availability could push crop and vegetable oil prices higher. Commenters warn that soybean oil demand is set to outpace production, squeezing food and export uses, forcing substitution to less economical inputs, and cascading costs onto livestock producers and consumers. They also contend the mandate would go well beyond domestic supply, diverting substantial vegetable oil from food to fuel, tightening global markets during the years needed to expand alternative supplies, and increasing reliance on imports of feedstocks and finished fuel-raising consumer costs while offering limited energy security benefits.

Response:

This rule does not finalize the proposed import RIN provisions. Therefore, they are not included in our assessment of how the final volumes affect the statutory factors. We have updated our price-impact analysis, as presented in RIA Chapters 9.3 and 9.4, using the most current data available at the time of analysis. The update incorporates a 2022 study by Lusk,[177] which finds that higher biofuel volumes are associated with a slight increase in soybean oil prices and a slight decrease in soybean meal prices. On net, we expect a small increase in food prices.

Finally, as described in RIA Chapter 7.2, we recognize that this rule is likely to increase demand for BBD. Consistent with market price signals, that additional demand is prompting new investment and expansions in soybean and canola crushing capacity in the United States and Canada, in addition to projects already underway. With domestic and Canadian feedstock supply expanding, we do not expect the mandate to require volumes well beyond domestic supply; rather, growth in U.S. and Canadian supply is expected to meet the incremental volumes.

Comment:

A commenter stated that the divergence of vegetable oils for use in biofuels led to a tripling of soy prices in 2021, and since then suppliers have had difficulty ensuring supply availability.

The commenter expressed concern that small- to medium-sized food producers would be unable to obtain vegetable oil if RVOs are set higher than actual food demand for any year.

The commenter added that if RIN generation for 2025 falls short of the total RVOs, the expected compliance deficit environment could once again lead to extreme fats and oils price movements and supply challenges.

Response:

We acknowledge that vegetable oil and soybean prices increased substantially in 2021 and recognize that multiple domestic and international factors contributed to higher market prices, including weather driven production declines and broader macroeconomic conditions, in addition to increased biofuel demand. We are unaware of any studies suggesting that the 2021 price surge is attributable to any single factor. Price changes are generally attributable to a confluence of many factors, and the commenter does not provide any literature or other evidence to demonstrate that this is not the case in this instance. Absent any such evidence, it is not appropriate to assume the 2021 price increase is attributable to biofuel demand, or to any other single factor.

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[177] Lusk, Jayson L. "Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil," November 10, 2022. https://ag.purdue.edu/cfdas/wp-content/uploads/2022/12/report_soymodel_revised13.pdf.

We acknowledge the concern that higher RVOs could constrain small- to mid-sized food producers' access to vegetable oils. Consistent with statutory requirements, we analyzed multiple factors when setting annual volume requirements. The projected volumes are achievable given feedstock availability. Further responses to comments on the proposed 2026–2027 volumes are provided in RTC Section 6.1.

We evaluated the potential for RIN generation in 2025 to fall short of the total RVOs. As discussed in RTC Section 6.1, should this occur, obligated parties have alternative avenues to meet their RFS obligations, including the use of RINs generated for imported renewable fuels, carryover RINs, and the deficit carryover provisions. Given these options, our cost analysis in RIA Chapter 10 indicates that the extreme feedstock price responses suggested by the commenter are unlikely to occur in response to the final volumes.

Comment:

A commenter argued that the RFS program skews markets toward biofuels and that EPA's assumptions about soy and canola crush capacity, feedstock availability, oil substitution, and imports are unrealistic and understate a significant vegetable oil shortfall that would divert supplies from food. The commenter urges EPA to avoid policies that offshore food production and fuel food inflation.

More specifically, they stated that:

1. The RFS program effectively provides a market-skewing monetary subsidy to biofuel producers that disadvantages food manufacturers in bidding for limited vegetable oil supplies.
2. EPA's projections that increased soy and canola crush capacity will stabilize the supply-demand curve are not plausible for two reasons: 1) there is a projected 2 billion pound shortfall in soybean oil supply for 2026 that will either drive imports or divert supplies from food and other markets, and 2) EPA overestimates feedstock availability and industry would need to divert 4.8 billion pounds of domestic fats and oils from current uses or import 9.6 billion pounds of foreign feedstocks.
3. EPA incorrectly assumes the oil substitution is feasible and that net BBD imports will not change.
4. EPA's process of using 2024 to forecast 2025 imports has understated the impact on feedstock demand by 5.6 billion pounds.
5. EPA should not force offshoring of America's food supply and consider the cumulative effects of RVO-driven food inflation in consideration of real-world price and supply shocks seen in recent years.

Response:

In response to the specific items raised by the commentor:

1. We acknowledge the commenter's concern that incentives to renewable fuel producers may affect competition for vegetable oil feedstock. We expect that in the long term, higher demand for these feedstocks will result in increased production and/or imports of

these feedstocks such that sufficient supplies will be available for both biofuel and non-biofuel markets. The RFS sets volume standards for qualifying renewable fuels and relies on tradable RINs for compliance. The program does not pay subsidies. RIN prices are determined by the market and the marginal cost of compliance, not by EPA. RIN values capture the marginal cost of compliance and provide incentives to supply renewable fuel.

2. We recognize that increases in soybean and canola crush capacity through 2027 alone will be insufficient to provide the feedstocks necessary to produce the increase in BBD production we are projecting in this final rule. We also expect that continued imports of FOG and diversions of these feedstocks from other markets will occur in these years. As detailed in RIA Chapter 7.2 and RTC Section 6.1, accounting for increased crush capacity, supply responses to price signals, and substitution within the global vegetable oil market, we do not project diversion of more than 20% of soybean oil from non-biofuel uses. Any displacement of soybean oil in food markets can be offset by eligible food-grade oils (including imports of soybean and canola oil), consistent with historical substitution patterns. The RIA Chapter 7 analysis does not require the magnitude of diversion or imports the commenter states.
3. We do not assume unconstrained oil substitution. Our analysis constrains substitution among oils based on technical suitability, end-use constraints, and observed own and cross price responses. We do not assume net BBD imports remain unchanged. EPA's statement on net BBD imports reflects a long-run projection: on average, we expect decreases in BBD imports to be largely offset by decreases in BBD exports, so we do not project significant changes to net BBD imports. It is not an assumption that net imports are fixed every year. Our modeling allows net BBD imports to vary year-to-year and includes sensitivity cases.
4. Based on available data from 2025 and changes to the 45Z credit since the Set 2 proposal, we have changed our projections of the imports of biofuels and feedstocks used to produce biofuels in this rule. We expect that imports of these products will be lower in 2026 and 2027 than observed in 2024. For more information on our projection of the imports of BBD and feedstocks used for BBD production, see RIA Chapter 7.2.
5. We do not expect that the final RVOs will force offshoring of U.S. food production or lead to significant food price inflation. We evaluated potential impacts on food and agricultural commodity prices in RIA Chapters 9.3 and 9.4. Our analysis does not indicate that the final volume standards will materially increase vegetable oil prices beyond the range driven by broader global market conditions. While it is possible that food producers may rely on imported vegetable oils in the short term, we expect that domestic production of these feedstocks will increase in the long term to satisfy demand in both biofuel and non-biofuel markets.

Comment:

A commenter said that EPA's RVO is pushing the feedstock demand curve beyond the capabilities of the supply curve economics. The commenter estimated that EPA's projected increase in soybean oil values for 2026 of just under $5 billion for 14.4 billion pounds consumed is in reality closer to $12.5 billion when accounting for total domestic food market impacts.

Response:

We acknowledge the commenter's concern about the link between renewable fuel demand and soybean oil markets. Our final volume standards reflect a balanced assessment of achievable renewable fuel supply. We do not agree that the RVOs push demand beyond the capabilities of the supply curve. We present analysis in RIA Chapter 7 describing the projected sources of feedstock for the final volumes which suggest sufficient supply will be available. We further observe that vegetable oil markets are driven by many factors and that the RFS program is only one of these factors. Regarding the claim on soybean oil values, our analysis on soybean oil price impact in RIA Chapter 9.3 implies marginal impacts attributable to the RFS program.

Comment:

A commenter stated that the combined policies of the RFS program, the Federal Blender's Tax Credit (BTC), and California's Low Carbon Fuel Standard (LCFS) program are causal factors contributing to soybean oil price spikes by adding a total program benefit of over $4.00 per gallon to transportation fuels. The commenter discussed the USDA July 2025 World Agricultural Supply and Demand Estimates report, stating that USDA projects for the first time in history that soybean oil use for biofuel production will be greater than soybean oil food use. The commenter presented data of feedstock projections for soybean oil and distillers corn oil in 2026-2027, stating that USDA's most recent forecast is 4.1 billion pounds less for soybean oil and 2.8 billion pounds less for distillers corn oil than EPA projects is needed to meet the proposed BBD RVOs in 2026.

Response:

We acknowledge the commenter's concerns regarding the role of multiple federal and state policies that provide incentives for renewable fuel production. We evaluate the impacts of the RFS program on feedstock markets as required by the statute but note that the Federal Biodiesel Blender's Tax Credit (BTC) and California's Low Carbon Fuel Standard (LCFS) program are administered by other entities.

We reviewed the commenter's reference to the USDA July 2025 report and recognize that USDA projects continued growth in renewable fuel use of soybean oil and that biofuel use may exceed food use in some years. EPA incorporates USDA projections into its feedstock analysis.

We evaluated the commenter's claim that USDA's most recent 2026–2027 projections for soybean oil and distillers corn oil are lower than the amounts EPA estimates would be needed to meet the proposed BBD volumes. EPA evaluates a set of feedstocks and factors in RIA Chapter 7 and finds that sufficient feedstock is available to meet the final volume standards without large diversion from food markets. In RIA Chapter 9, we present analysis describing the potential impacts on vegetable oil prices. As discussed elsewhere in this section, we believe those impacts are reasonable when balanced with the other projected impacts of the final volumes.

Comment:

A commenter asserted that EPA has not sufficiently studied the effects that importing higher levels of vegetable oil would have on agricultural commodities and food prices, making the DRIA arbitrary and capricious. The commenter urged EPA to adopt an analytical framework that informs the agency of the impact of the RVOs on vegetable oil price and supply to meaningfully evaluate the statutory factors.

Response:

We acknowledge the commenter's concern about the potential effects of increased vegetable oil imports on agricultural commodity markets and food prices. Since the Set 2 proposal, EPA has updated its analysis on supply and price of agricultural commodities in RIA Chapters 9.2 and 9.3. For example, in Chapter 9.3, our analysis for soybean oil price impact uses a rigorous linear equilibrium displacement model from the literature, which maps biofuel demand shocks to commodity prices. We then quantify 2026 and 2027 price impacts for the project volumes relative to the No RFS Baseline. This analysis represents a significant improvement in analytical robustness compared to the DRIA and we believe it is adequately responsive to the comment. This analysis makes clear that EPA is not ignoring these potential impacts but rather is making a good effort to analyze them robustly within available time and resources. We will continue to evaluate the statutory factors including impacts on food and agricultural commodities using the best available data and established analytical methods.

Comment:

A commenter urged EPA to partner with USDA to evaluate impacts on the price and supply of food and agricultural commodities.

Response:

EPA appropriately coordinated with USDA in relation to this rule pursuant to statutory requirements. In addition to ongoing interactions at the staff level, EPA also engages in formal interagency review of this rulemaking with several other federal agencies, including USDA.[178]

[178] See "Documentation of Coordination with USDA and DOE," available in the docket for this action.

9.1.6 Rural Economies (Rural GDP and Agricultural Employment) and Farm Income

Comment:

A commenter expressed support for EPA's analysis within the section titled "Jobs and Rural Economic Development" and EPA's recognition of the broader economic benefits associated with renewable fuel production. Similarly, other commenters expressed support for EPA's inclusion of benefits in the proposed rule and DRIA. A commenter said that expanding new markets for agricultural commodities, like renewable fuels, can place the nation at the forefront of renewable energy production and use. Several commenters highlighted the positive economic impacts of renewable fuels on rural economies, including revenue diversification, increased tax revenue, reduced input costs, local job creation, reduced waste volume, and improved energy access and reliability.

Response:

We appreciate the commenters' support for our jobs and rural economic development analysis and the additional information submitted regarding the ways in which renewable fuels may benefit rural economies (*e.g.*, revenue diversification, local job creation, increased tax revenues, reduced waste volumes, lower input costs, and improved energy access and reliability). Consistent with benefit-cost analysis practice, we treat these effects as distributional impacts rather than net social benefits. Increases in rural jobs or GDP in biofuel-related activities are likely accompanied by partially offsetting declines elsewhere in the economy as labor and capital reallocate. We therefore anticipate some job and GDP losses in other sectors or regions. To the extent these changes reflect transfers rather than changes in real resource use, they are viewed as distributional effects and not counted toward net social benefits. We agree that renewable fuel production can play an important role in supporting rural communities and have retained and clarified discussion of these effects in the final rule and RIA Chapter 9.1.

Comment:

A commenter, citing multiple studies, stated that the use of forest biomass to create paper products and wood products (including associated renewable energy production) provides significantly more jobs and economic value than using biomass solely to produce energy.

Another commenter discussed the important role that rail will play in the renewable fuels value chain and in transporting feedstocks and finished productions in support of the RVO. The commenter said that transporting the feedstocks via rail will further lower the carbon intensity of the biofuel and support high-paying rail jobs.

Response:

We acknowledge the commenter's submission and the cited studies regarding the relative employment and economic value associated with the use of forest biomass in paper and wood product manufacturing, compared to the use of biomass solely for energy generation. The RFS program applies to renewable fuels as defined under the Clean Air Act, and the RIA evaluates economic impacts associated with qualifying renewable fuel pathways within that statutory framework. Eligible forest biomass is defined by statute and regulation, and only approved pathways qualify for RINs. Although there is longer-term potential for growth, for 2026 and 2027, we project minimal RIN generation from qualifying forest biomass. Our discussion of these projections can be found in RIA Chapter 7.

We recognize that rail can serve as an important logistics pathway for certain feedstocks and that increased reliance on rail transportation may support employment in the rail sector. RIA Chapter 8 considers distribution infrastructure relevant to renewable fuel production and delivery. Transporting feedstocks and fuels by rail is considered as part of the climate change analysis for this rule (see RIA Chapter 5).

Comment:

A commenter raised concerns about EPA's economic impact analysis. The commenter said that EPA claims that the proposed volumes are supported by their positive impact on rural economies. For example, the commenter noted that while EPA claimed the proposed volumes for crop-based biofuels would lead to roughly 100,000 jobs and around $10 billion in economic development per year, EPA admitted that these estimates do not represent net increases in jobs and rural GDP, but rather likely some migration of jobs and capital from other sectors of the rural economy. The commenter concluded that, on a net level, EPA finds at best minimal benefit to rural economies.

Response:

We acknowledge the commenter's concern. As explained in the Executive Summary (Table ES-1) and RIA Chapter 9, we report projected employment and rural economic development impacts to describe the scale and regional distribution of economic activity associated with increased renewable fuel production. RIA Chapter 9.1 explicitly notes that these estimates do not necessarily represent net national increases in jobs or GDP and distinguishes between gross economic activity and net societal welfare effects. Increased demand for agricultural feedstocks may expand economic activity in certain rural regions, while adjustments in fuel markets may reduce activity in other sectors or regions, including fossil fuel-producing areas; some effects therefore reflect reallocation of labor and capital rather than net national gains, as mentioned earlier in this section. For this reason, rural economic impacts are presented separately and are not included in the monetized societal benefit totals in Table ES-1 and RIA Chapter 10.6.

Comment:

A commenter criticized EPA's treatment of biodiesel, renewable diesel, and jet fuel as one "biomass-based diesel" market, arguing that this approach ignores key differences between these fuels and markets and renders their review of the statutory factors fundamentally flawed. The commenter suggested that this allows renewable diesel to be credited with benefits associated with biodiesel production. The commenter also noted that EPA's DRIA did not reference biodiesel specifically, looking instead at a study that conflated biodiesel and renewable diesel in assessing job and economic impacts.

Response:

We disagree that EPA's analysis improperly conflates biodiesel, renewable diesel, and jet fuel. The Clean Air Act defines "biomass-based diesel" as a single statutory category that includes biodiesel and renewable diesel (and the co-located sustainable aviation fuel) meeting specified lifecycle GHG thresholds, and EPA's analysis is structured consistently with that statutory framework. The RIA evaluates impacts at the BBD category level while also discussing fuel-specific trends where relevant, including differences in production capacity, feedstock use, imports, and other factors (see, for example, RIA Chapter 7).

We acknowledge the commenter's concern that the RIA cited studies that evaluate biodiesel and renewable diesel jointly when assessing employment and economic impacts. We relied on the best available data that characterize economic activity within the BBD sector and established modeling tools that assess economic activity associated with BBD production. Because upstream effects (*e.g.*, feedstock procurement and transportation) are common to both biodiesel and renewable diesel, evaluating them at the category level is appropriate. The analysis does not attribute biodiesel-specific benefits to renewable diesel; rather, it estimates impacts associated with total BBD demand.

While fuel-specific market differences exist, we conclude that evaluating impacts at the statutory category level, supplemented by discussion of key distinctions, provides a reasonable and consistent basis for reviewing the statutory factors. However, should future analytical work and data support separate analysis of the impacts of biodiesel and renewable diesel on rural economic development, we may incorporate those findings into future rulemaking analyses.

Comment:

A commenter said that the RFS program failed to boost the domestic economy, and the proposal does not help achieve this goal. The commenter said that, as explained in the DRIA, the growth of biofuels contributes to the ongoing trend of U.S. farmland consolidation, pushing small farms out of business because crops like corn and soy are often cultivated in large monocropping operations. The decline of midsize and small farms has intensified economic and social difficulties in the rural Midwest and many local communities. Another commenter stated that the current proposal puts a strong emphasis on increasing the rural and economic benefits of the RFS program and the proposed imported feedstock RIN reduction mechanism is intended to maximize domestic economic benefits by rewarding producers sourcing domestic feedstocks. However, as described earlier, the commenter said that the proposed volumes significantly exceed domestic feedstock supplies, in effect forcing fuel producers to outbid existing non-fuel users of fats and oils or source supply from abroad.

Response:

We acknowledge the commenter's observation that broader structural trends in U.S. agriculture—such as consolidation of farmland and shifts in farm size—have contributed to economic and social challenges in some rural communities. However, we disagree that the RFS has failed to contribute to the domestic economy; we agree that the proposed volumes would benefit the rural economy and expect the final volumes to do so as well.

As detailed in RIA Chapter 9.1, we assess employment and rural economic development effects, including the types of impacts identified by commenters (*e.g.*, on farms of varying sizes). Many of these effects are distributional—shifting activity across sectors and regions—and do not necessarily imply net changes in national economic welfare. Overall, our analysis indicates positive net impacts on farms and the rural economy. Trends in farmland consolidation predate the RFS and reflect broader forces such as technological change, global markets, and productivity growth; the RIA does not identify the Analyzed Volumes as a primary driver of farm structure outcomes. Although we do not quantify potential effects of biofuel feedstock demand on farm size, to the extent these ongoing trends in farm size are linked to demand for biofuel feedstocks and continue into the future, they may affect the magnitude of employment and rural economic development impacts associated with our RFS program standards.

We acknowledge the commenter's view that the proposed volumes could exceed domestic feedstock availability, potentially requiring producers to compete with existing non-fuel markets or rely on imported feedstocks. We also note that we are not finalizing the import RIN reduction proposal in this action. We present analysis in RIA Chapter 7 describing the projected sources of feedstock for the final volumes which suggest sufficient supply will be available. As described further across RIA Chapter 7, we also project that a large majority of the incremental fuel associated with the final 2026 and 2027 volumes—relative to the No RFS Baseline and 2025 Baseline—will be sourced from domestic feedstocks.

Comment:

Some commenters reaffirmed the research EPA included in its analysis of the employment and economic output impacts of RNG, which showed that the RNG industry supported over 55,000 jobs and generated $7.2 billion in GDP in 2024. Multiple commenters provided detailed information about the economic benefits of RNG projects. The commenters stated that RNG projects can support rural economic development by offering a wide range of potential revenue streams.

Response:

We acknowledge the commenters' support for our analysis of the employment and economic output associated with RNG and appreciate the additional information submitted regarding the economic benefits of RNG projects and the ways in which such projects may contribute to rural economic development. We have reviewed the information provided by commenters and have retained discussion of these potential economic impacts in the final rule and RIA.

Comment:

A commenter highlighted that on-farm and municipal digesters can process waste from external sources, providing additional income from the sale of RNG and from providing an organic waste processing service.

Another commenter said their industry-leading projects could create an estimated $6-10 billion in economic benefit for farmers through RNG production and use of alternative fertilizers resulting from the biodigestion process.

Response:

EPA acknowledges the commenter's observation that on-farm and municipal anaerobic digestion facilities may accept organic waste from external sources and generate additional revenue and another commenter's assertion that industry-leading projects could generate substantial economic benefits for farmers through RNG production and the use or sale of alternative fertilizers produced via biodigestion. EPA recognizes that, by enabling multiple revenue streams, such projects may provide additional income for agricultural operations and support broader economic activity in some rural areas.

Comment:

A commenter noted that RNG projects "are complex and require a high degree of engineering sophistication, relying on the expertise of contractors, technicians, construction workers, and plant operators in the process."

Response:

We acknowledge the commenter's observation that RNG projects can be complex undertakings that require significant engineering expertise and the involvement of contractors, technicians, construction workers, and plant operators. We recognize that the development and operation of RNG facilities may support a range of skilled labor and technical occupations. We have reviewed the information submitted and have retained discussion of the technical and operational characteristics of RNG projects, as well as their associated labor needs, in the final rule and RIA.

Comment:

The commenter noted that increased RNG development and use results in millions of dollars in capital investment per project, with total capital costs for smaller landfill projects ranging from $5 million to $25 million, and upwards of $100 million for larger projects, including agricultural and wastewater projects. Based on information provided by member companies, the commenter estimates that the average RNG project requires $17 million of capital investment.

Response:

We recognize that RNG developments entail significant capital investments and such investments can contribute to economic activity in certain regions and sectors. As discussed in RIA Chapter 9, the impacts to the local economy from investment in new renewable fuel production facilities, including increases in employment, output and income, and the subsequent increases in demand for local goods and services all create additional beneficial ripple effects. EPA evaluates these capital expenditures as distributional impacts rather than net social benefits for purposes of benefit-cost analysis. We welcome project level documentation and may be able to incorporate verified data to improve transparency and refine assumptions in future analyses.

Comment:

A commenter suggested that EPA explicitly reference dairy-derived RNG and BBD in the final rule's environmental and economic impact analysis to highlight their contributions and encourage research and development funding for advanced anaerobic digestion technologies to enhance the efficiency and scalability of dairy biogas projects.

Another commenter stated that, given these benefits, the foundation of any "America Energy Dominance" strategy must include American RNG. As part of such a strategy, the commenter said that the federal government should take full advantage of the substantially under-leveraged and geographically dispersed energy resources available across the nation in the form of decaying, biomethane-producing organic waste that can be captured, converted, and beneficially utilized.

Response:

While decisions about federal research funding and national energy policy are beyond the scope of this rulemaking, EPA recognizes the potential of dairy-derived RNG and related technologies and acknowledges stakeholder views that RNG could be foundational given substantial underutilized organic waste resources. In evaluating the potential impacts of this rule, EPA considered dairy-derived RNG as well as RNG from other sources such as landfills and wastewater treatment facilities. In establishing the applicable volume requirements, EPA assessed the availability of qualifying feedstocks and the potential contributions of RNG in its evaluation of the statutory factors.

Comment:

Several commenters emphasized the importance of the RFS program for continued growth in the renewable fuels industry which supports thousands of jobs and generates billions in GDP. A commenter stated more specifically that the RNG industry has grown substantially thanks to the RFS program, increasing from 47 operating facilities before RNG qualified to generate D3 RINs to 505 operational facilities throughout North America as of July 2025. The commenter noted that the RFS program has helped create, protect, and expand market demand for RNG in exchange for the numerous economic, environmental, and energy security benefits the industry brings.

Response:

EPA acknowledges the commenters' views regarding the role of the RFS program in supporting growth within the renewable fuels industry, including the employment and economic activity associated with renewable fuel production. EPA also notes the information submitted regarding the expansion of the RNG industry since RNG first qualified to generate D3 RINs, including the commenter's statement that the number of operational facilities in North America has increased significantly through 2025. EPA recognizes that the RFS program has contributed to the development of markets for qualifying renewable fuels, including RNG, and that such development may support economic, environmental, and energy-related outcomes in certain regions and sectors.

We have reviewed the information submitted and have retained discussion of the growth of the renewable fuels industry, including RNG, in the final rule and RIA.

Comment:

A commenter expressed concern that elements of EPA's Set 2 proposal threaten to undermine progress in the biogas industry, especially for dairy and other livestock farmers, whose operations rely on RNG production and would be disproportionately harmed by a retreat from full recognition of this renewable fuel. The commenter stated that these farmers and small communities rely on the RFS program to turn waste into stable income. The commenter argued that full support for RNG in the RVO will ensure that farmers and other producers can continue to invest in domestically produced bioenergy.

Response:

We recognize that biogas-derived RNG can reduce methane emissions from organic waste management, contribute to the renewable fuel supply, and provide local economic benefits in rural communities. The projected final volumes balance the statutory factors, reflecting expected contributions from multiple pathways, including RNG. The RIA estimates incremental national impacts while acknowledging that local effects may be larger in some communities. Overall, we estimate that the projected final volumes will support meaningful additional growth in demand for RNG and that this will likely benefit producers of RNG on the whole. See RIA Chapters 7 and 9 for more information. EPA reviewed the information provided by commenters regarding RNG and its rural impacts and will continue to monitor RNG market developments.

Comment:

A commenter argued that ensuring an ongoing role for biodiesel would support incentives for the market to invest in infrastructure (versus "drop-in" renewable diesel) and provide benefits including positive impacts on employment and the economy, particularly for farmers and retailers that distribute biodiesel, reducing the need for petroleum imports, and providing greater GHG emissions reductions. The commenter expressed concern that while EPA is projecting a role for biodiesel with the increased volume requirements it is proposing, there are no assurances under EPA's proposal as to the actual gallons that will be required. Another commenter stated that with the RFS program and market certainty, BBD fuels will continue to drive job creation, energy security, and decarbonization.

Response:

EPA acknowledges the commenters' views regarding the roles of biodiesel and renewable diesel within the RFS program and the potential economic, employment, and energy security benefits associated with continued production and use of BBD fuels. EPA recognizes the commenter’s assertion that maintaining a meaningful role for biodiesel may support infrastructure investment, provide economic opportunities for farmers and fuel retailers, reduce reliance on petroleum imports, and contribute to GHG emissions reductions. EPA also notes the commenter’s concern that, although the proposed volume requirements project continued use of biodiesel, the proposal does not guarantee specific volumes of biodiesel relative to renewable diesel. EPA further acknowledges the additional commenter’s view that the RFS program and regulatory certainty can support job creation, energy security, and decarbonization through continued growth in BBD production.

We recognize biodiesel’s environmental and economic benefits and assess them in the RIA. The RFS is technology neutral; numerous biodiesel and renewable diesel pathways are approved to generate RINs and can contribute to the BBD, advanced, and total volume standards. EPA does not mandate or guarantee a specific biodiesel share within BBD and actual gallons depend on market conditions and infrastructure. Final volumes balance statutory factors, with expected contributions from biodiesel. EPA promotes predictability through multiyear standard setting, transparent methods, and program flexibilities, and will continue to monitor markets and consider relevant data consistent with statutory authority.

Comment:

A commenter stated that market volatility tied to negative RFS policy rumors, such as pending SRE petitions, has led to sharp commodity price swings, including at one point a 28-cent drop in soybean prices, and stifled SBO trading. The commenter said that these disruptions ripple through the entire supply chain, affecting farmers, processors, and renewable fuel producers. For every 100 acres of soybean production, that 28-cent drop translates to a direct loss of approximately $1,470—a meaningful hit to farm income.

Response:

We acknowledge the commenter’s concerns regarding market volatility associated with uncertainty surrounding the RFS program, including rumors related to SRE petitions.

Commodity price movements may be influenced by a range of factors, including global supply and demand conditions, weather variability, trade developments, energy prices, and market expectations. The RIA’s analysis focuses on projected incremental impacts associated with the projected Analyzed Volumes rather than short-term price fluctuations linked to external developments or market sentiment.

Comment:

A commenter stated that employing innovative digester systems with appropriate control of the nutrients, digestate solids and liquids, and air emissions could be a “win-win” for farmers, communities, the environment, and project investors. The commenter, along with another, noted that these efforts may lead to voluntary reductions in GHGs and other air pollutants, pathogen load in runoff from farms, and the amount of organic wastes going to landfills.

A commenter stated that dairy manure-to-RNG projects are critical to addressing environmental challenges through methane capture and renewable fuel production.

Response:

EPA acknowledges the commenters' observations that innovative anaerobic digester systems, may provide multiple benefits for farmers, local communities, project developers, and the environment. In RIA Chapter 4.1, we evaluate the environmental implications of renewable fuel pathways, including anaerobic digestion. Comments on GHG emissions associated with the Analyzed Volumes are addressed in RTC Section 9.2.1.

9.1.7 Jobs and Profitability of Biofuel Producers

Comment:

Multiple commenters stated that biodiesel and ethanol production deliver significant job creation and economic gains, particularly in rural states. They note that South Dakota is now the nation's fourth-largest ethanol producer, operating 16 plants with a combined annual capacity of 34 million barrels. A 2024 analysis projects more than 14,000 additional construction and permanent jobs from continued ethanol expansion. In Iowa, the biodiesel sector generated over $410 million in household income, underscoring its importance to rural economies. Nationally, biomass-based diesel activity in 2024 supported $60.25 billion in economic output and 145,700 jobs across both the energy and agricultural sectors.

Response:

We appreciate the comments describing the employment and economic activity associated with ethanol, biodiesel, and biomass-based diesel production, including the contributions of facilities in South Dakota, Iowa, and other rural states, as well as national estimates of economic output and jobs supported by the biomass-based diesel sector. Renewable fuel production can play a significant role in rural economies through construction employment, ongoing plant operations, and associated household income. We have reviewed the information provided and have incorporated updated data on renewable fuel production and related economic activity into the final RIA. See RIA Chapters 7 and 9 for more information.

Comment:

Several commenters state that strong renewable fuel standards stimulate domestic innovation, manufacturing, and job creation in rural America and across the bioeconomy—sending clear investment signals to producers and technology developers. Others caution that RVOs set above achievable consumption or domestic production can spike RIN costs, harm small and independent refiners, introduce market unpredictability, and risk refinery job losses—undermining sector profitability.

Response:

EPA sets volumes by balancing statutory factors and the best available data on renewable fuel supply and consumption, infrastructure, and feedstock availability. The final RVOs reflect updated projections of renewable fuel availability, consumption capacity, and RIN market dynamics to ensure the standards are achievable while supporting program stability.

We recognize rural economic benefits of strong standards and quantify these in the RIA. See more responses in RTC Section 9.1.6. We acknowledge concerns about RIN costs and rely on program flexibilities such as carryover RINs, trading, and waiver authorities to support feasibility. Evidence indicates substantial pass-through of RIN values to wholesale fuel prices, which can mitigate net compliance costs. For small refineries, EPA implements the statutory hardship provision. EPA will continue to monitor market conditions and pursue timely, transparent standard setting to promote predictability while achieving statutory objectives.

Comment:

Some commenters also contend that EPA understates the employment and income contributions of biodiesel plants operating in small rural communities.

Response:

We acknowledge commenters' concerns and recognize that the local economic importance of biodiesel plants in small rural communities can be substantial.

The RIA focuses on incremental changes from the final standards relative to the baseline, not on total existing employment. Because many biodiesel plants are already operating, incremental changes in volumes often translate into modest national employment impacts—even though the local significance of a plant in a small community can be substantial. We estimate direct, indirect, and induced employment and income effects using transparent, publicly available data and widely used economic relationships (*e.g.*, input–output multipliers from reputable sources) and believe the final RIA's estimates are reasonable and conservative.

We welcome additional plant-level employment and payroll data, county-specific multipliers, and documentation of local spending patterns for future analyses. We will continue to refine methods to better reflect rural heterogeneity while maintaining consistency with best practices.

9.1.8 Impact of the Standards on Refiners

Comment:

A commenter argued that EPA's proposal would dramatically and unnecessarily increase the cost of the RFS program by setting conventional biofuel volumes above the ethanol blendwall. Other commenters said that "haphazard and arbitrary" blending requirements have been particularly harmful to independent refiners, who generally do not have large-scale blending operations and are thus left with no alternative but to purchase RINs for program compliance.

Response:

If the conventional volume standard were set at or just below the E10 blendwall, D6 RIN prices would be expected to decrease substantially, potentially down near zero. However, lower D6 RIN prices would not reduce the cost of the RFS obligation on petroleum-based fuels if the standards cause the same mix and volume of biofuels. Lowering the conventional standard would increase the effective price of ethanol by reducing the value of the RIN generated when qualifying ethanol is produced, and it would likely shift some of the price impact from diesel fuel to gasoline. If the conventional standard were lowered to the blendwall, it would remove the requirement for blending in higher ethanol blends, such as E15 and E85 which would not be in line with the goals of the program.

Comment:

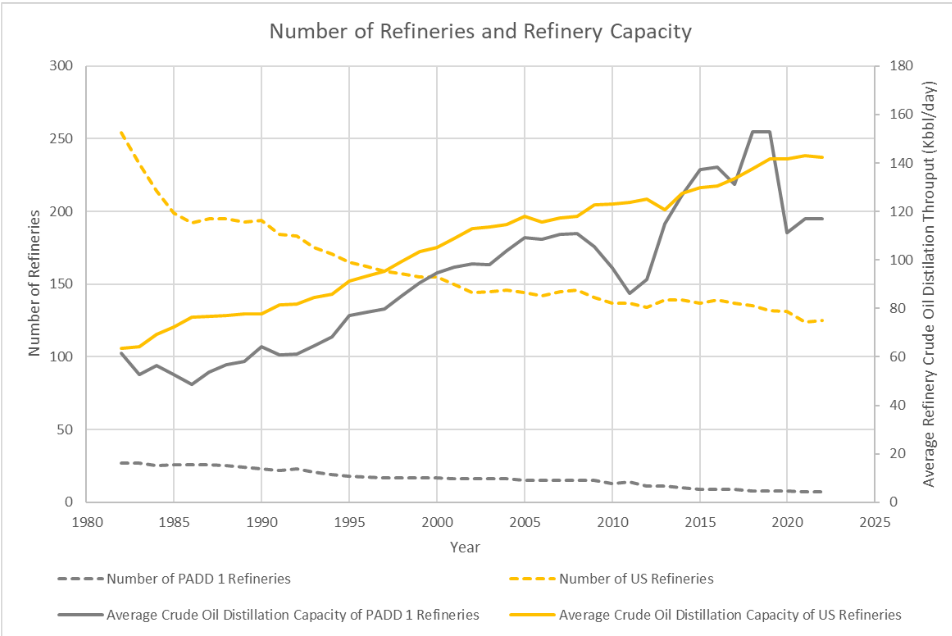
Several commenters noted that the surge in RIN prices, coupled with declining demand for refined products, puts the economic feasibility of some refineries at risk.

The U.S. has lost 1.4 million barrels per day of refining capacity on the East and West Coasts alone since 2010, while another commenter stated that the U.S. has lost over 1.4 million barrels per day of collective refining capacity since 2019. The commenters stated that on the East Coast where 35% of the U.S. population lives, just four large refineries remain. Other commenters pointed out that since January 1, 2025, one refinery has closed and two refineries have announced plans to close by the second quarter of 2026, resulting in the loss of more than 500,000 barrels per day of refining capacity and hundreds of jobs. Commenters were specifically concerned about the refineries in New Jersey, Pennsylvania and also Ohio. Commenters stated that the loss of U.S. refinery capacity has weakened our national energy security posture.

Many other commenters said that the current structure of the RFS program has led to the reduction of millions of barrels of daily collective refining capacity as a result of refinery closures.

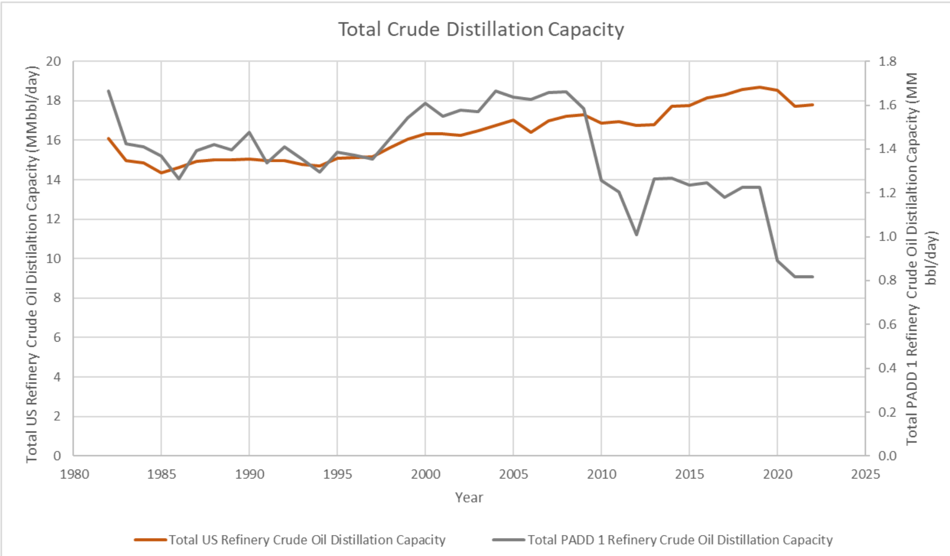
Response:

It is important to understand that the closure of some facilities and the expansion of others is a natural process of any industry as it matures, and the refining industry, including refineries located in PADD 1, has been experiencing this process for decades.[179] The figure below shows the decline of both total U.S. refineries and PADD 1 refineries from the early 1980s to 2022. While the number of refineries has been declining, U.S. production of refined products has not been declining and the crude oil atmospheric distillation capacity, and the associated downstream refining units, at the remaining refineries has been increasing to offset the reduction in the number of refineries. This change is also shown in the figure below.



The figure shows that the total number of U.S. refineries declined by 129, or slightly more than half since 1982. PADD 1 experienced a drop of 20 refineries during the same time period, which is a decline by about three quarters of the number of refineries which were operating back in the early 1980s in PADD 1. The PADD 1 average atmospheric crude oil distillation capacity vacillated in 2009 to 2022 timeframe due to various PADD 1 refinery shutdowns. The closure of those PADD 1 refineries had a large impact on total atmospheric crude oil distillation capacity in PADD 1 as shown in the next figure which compares the total atmospheric crude oil distillation capacity of PADD 1 to that capacity for the entire U.S.

[179] Meyer, David W., and Christopher T. Taylor. "The Determinants of Plant Exit: The Evolution of the U.S. Refining Industry." *Journal of Industry Competition and Trade* 18, no. 4 (March 14, 2018): 429–48. https://doi.org/10.1007/s10842-018-0273-8. PADD 1 is the petroleum distribution area that includes states along the East Coast.



The above figure shows that PADD 1 atmospheric crude distillation capacity decreased from 1.6 million barrels per day in 2008 to 1.2 million bbl/day in 2011, and then dropped down to about 0.8 MMbbl/day in 2020.

It is important to understand the economic environment in which the PADD 1 refineries operated because it is this economic environment and certain economic impacts, and probably not the RFS program, which led to the closure of the refineries there. There were three different economic impacts on the PADD 1 refineries. The most important factor affecting the refining economics of the PADD 1 refineries is the lack of access to sufficiently low-priced crude oil.[180] For the most part, PADD 1 refineries relies on outside sources of crude oil at the going market price plus distribution cost, while at the same time competing with the refined products produced by Gulf Coast and European refineries. The above figure shows that PADD 1 refineries were increasing their crude oil refining capacity, consistent with all U.S. refiners, up until 2007, and then declined in 2009. What changed in that timeframe is that crude oil prices began to increase above their $25–$35/bbl range up to over $100/bbl in 2008. The PADD 1 refineries are predominantly sweet crude refineries. As the price of the light, sweet crude that PADD 1 refineries processed increased these refineries were undercut by the heavy-sour crude refineries in the Gulf Coast processing cheaper crude oil, which could send their product up the Colonial pipeline into PADD 1.[181]

Furthermore, PADD 1 refineries pay more than Gulf Coast refineries for natural gas which is an important input to refineries for providing heat and producing hydrogen for its refining processes. During the years 2008 to 2013, natural gas prices for industrial consumers in Pennsylvania were paying over $4 per thousand cubic feet higher prices than industrial consumers in Texas.

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[180] American Fuel & Petrochemical Manufacturers, "U.S. Refineries Competitive Position," 2014 EIA Energy Conference, July 14, 2014.
[181] The Colonial pipeline has a throughput capacity of 2.5 million barrels per day. Colonial Pipeline, "Our Operations," https://www.colpipe.com/our-operations.

The third factor is the lower demand for refined products due to the Great Recession which began at the end of 2007. From 2008 to 2013, U.S. gasoline demand dropped by 4.7 billion gallons per year, or 3.4%. The reduced gasoline demand reduced refinery utilization rates to the low to mid-80% range, much lower than the typical 90–95% range. This challenging period placed significant economic pressure on the refineries with the lowest margins, such as those refineries in PADD 1 which were paying higher prices for crude oil and natural gas. It was this challenging 4-year period from 2008 to 2012 which resulted in the closure of four PADD 1 refineries.

The period from 2013 to 2020 started out as a good economic period for PADD 1 refineries. This period saw dramatically increasing U.S. light, sweet crude oil production due to fracking of shale oil deposits in the Bakken and Eagle Ford shale plays in Bakken North Dakota and Southwest Texas, respectively, and some modest crude oil production from shale plays in Pennsylvania and East Ohio. Due to the lack of pipelines for moving crude oil out of North Dakota, this light sweet crude oil became available to the PADD 1 refineries by rail from the upper Midwest at a discount even with the rail transportation cost added on.[182] As a price marker, WTI crude oil was discounted to Brent by over $6/bbl. Until late 2015, a crude oil export ban was in place which forced this light sweet crude to be used in the U.S. and Canada, causing it to be priced even lower to WTI.

When the U.S. crude oil export ban was ended by Congress at the end of 2015, the U.S. began to export some of this fracked oil and its price increased somewhat, but WTI still remained at a discount to Brent by about $4/bbl. But PADD 1 refiners did not find it advantageous to refine this domestic crude oil anymore and instead went back to purchasing foreign crude oils, but paying a price premium compared to other domestic refineries which could purchase the U.S.-produced discounted light sweet crude oils or discounted heavy crude oils.[183] In addition to more expensive crude oil, the natural gas price premium paid by Pennsylvania refiners increased to over $5/thousand cubic feet compared to that of refineries in Texas. During this time, PADD 1's largest refinery, the 335,000 bbl/day Philadelphia Energy Solutions refinery closed. In addition to the challenges facing other refiners in PADD 1, a high debt to equity ratio and apparent mismanagement of its renewable fuels blending obligations under the RFS program were additional reasons provided for why the company and this refinery struggled.[184] The company declared bankruptcy in 2018, but the continued tough market conditions along with a major explosion at the Philadelphia refinery caused the company to cease operations at the refinery in mid-2019.

Ultimately, while we do not dispute that the total number of operating refineries and total refining capacity in PADD 1 has declined since 2010, these reductions are largely due to the broader market conditions described above, rather than the impacts of the RFS program on PADD 1 refiners. Since we find that refiner closures in PADD 1 mentioned by the commenter are

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[182] EIA, "East Coast refiners receiving more domestic crude oil from Gulf Coast by tanker and barge, *Today in Energy*, September 20, 2018.

[183] U.S. Government Accountability Office, "Crude Oil Markets: Effects of the Repeal of the Crude Oil Export Ban," GAO-21-118; October 2020.

[184] Stone, Anthony, "After Explosion, Philadelphia Refinery to be Permanently Shutdown," *Forbes*, February 17, 2020. https://www.forbes.com/sites/andystone/2020/02/17/with-ample-drama-largest-east-coast-refinery-meets-its-end.

due to broader market conditions and not the RFS program, if the PADD 1 refinery closures are impacting the U.S.' energy security position in any way, it cannot primarily be attributed to the RFS program.

Other factors also affect petroleum fuel demand. Today's internal combustion engines are more efficient, traveling the same distance while consuming less fuel. Also, while still small, the purchase of electric vehicles is increasing, slowly displacing petroleum demand.

The RFS program is not the cause for all the increased volume of renewable fuels consumed in the U.S. Our analysis shows that all the corn ethanol consumed as E10 and some of the BBD fuel would be consumed regardless of the RFS program which is depicted in our estimate of the No RFS baseline. Incentives outside the RFS program, such as federal subsidies and state mandates and incentives help to make renewable fuels more economic.

Comment:

Commenters stated that RIN prices are so expensive that refineries have reported spending more on RINs than they do on salaries, benefits, maintenance, and utility costs. One commenter said that this year alone, RIN prices have increased 75% since January 2025, but without any corresponding increase in biofuel production or in the percentage of ethanol blended into gasoline. The commenter said that the excessively high cost of RIN credits threatens economic vitality and diverts capital from being invested into facilities and local economies.

Response:

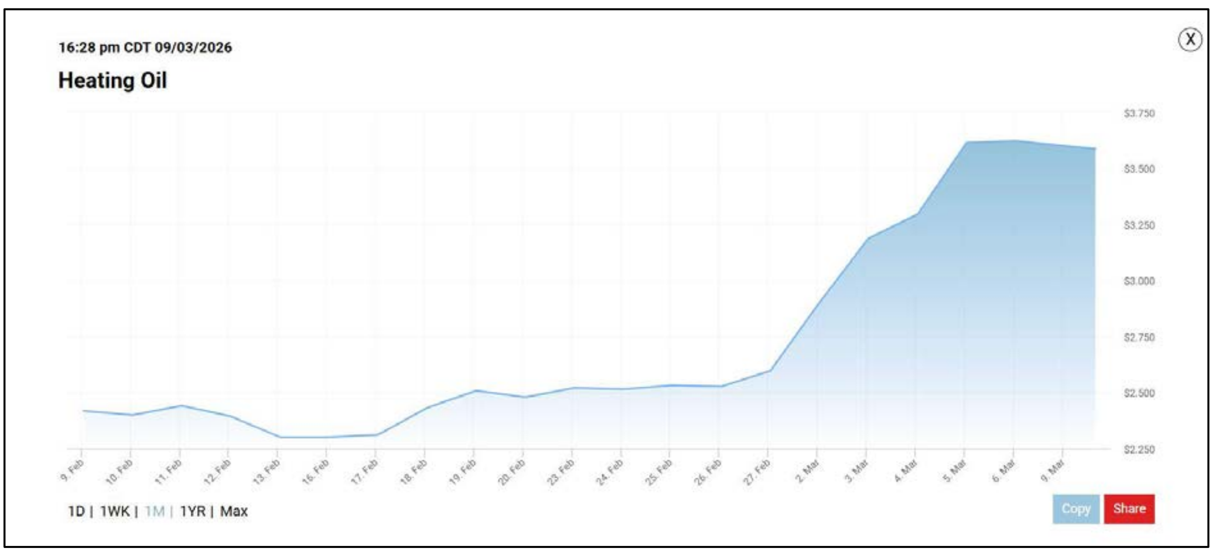
As discussed in greater detail in RTC Section 9.1.1, RIN prices are amortized over the refiner's fuel production and, on average at the nationwide scale, is passed on to the consumer. Thus, the RIN cost is recovered from the refinery sales.

Comment:

A commenter said that EPA ignores the unique operational and economic realities of small refineries. The commenter said that throughout the DRIA, EPA relies on outdated projections and comparisons "divorced" from the reality faced by small refiners. Additionally, the commenter said that EPA's discussion of "supply" and price competitiveness assumes all refiners can respond similarly to market signals. The commenter said that EPA stated both (1) "Crude oil prices have a significant impact on the economics of increased use of renewable fuels. When crude oil prices increase, both renewable fuel feedstock prices and gasoline and diesel prices tend to increase as well, although gasoline and diesel prices generally increase more relative to renewable fuel feedstock prices"; and, (2) "Additional use of renewable fuels and renewable fuel feedstocks can dampen price impacts from oil price shocks, if these prices are largely uncorrelated, but will result in new exposure in the renewable fuel markets." The commenter stated that EPA cannot contradict itself, stating that prices are related but also "uncorrelated." The commenter also said that it is inaccurate for EPA to claim that renewables can dampen price impacts from oil price shocks, as renewables are only 5–10% of the composition of fuel. This is insufficient to dampen price impacts from any “shock.” Additionally, the commenter said that comparing imports or heavy oil to a renewable fuel program volume mandate is arbitrary.

Response:

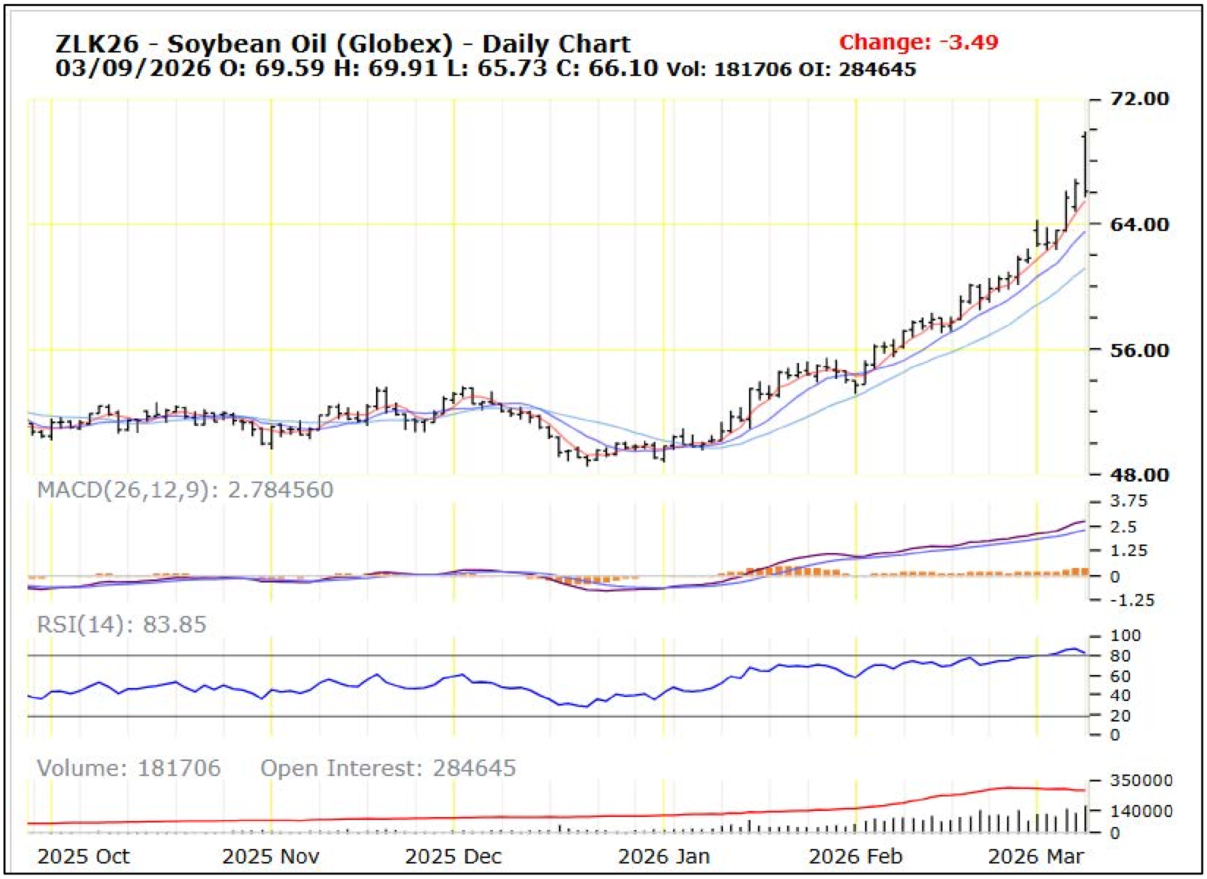
In RIA Chapter 10, we estimate an association between crude oil prices and vegetable oil, fat, and corn prices which are feedstocks for renewable fuels. This association most likely exists over a medium to longer term basis. Thus, when crude oil prices rise, it will impact the cost of planting, growing, harvesting and distributing these renewable fuels feedstocks. On a shorter term basis where the price of renewable fuels feedstocks are determined when they were produced, which is likely months in the past, but petroleum prices are determined by a recent very near term price spike, we likely will see a distinct, much smaller, price association. Current events help to show the price impact disconnect for shorter term petroleum price spikes. There has been a significant price impact on petroleum prices attributed to military activity in the Middle East which has impacted the flow of petroleum transported through the Straits of Hormuz. The figure below shows U.S. heating oil prices from February 9 to March 9, and captures the price impact after the start of the military activity (February 28) and reduced petroleum transport impact on prices.



Source: Oilprice.com, “Oil Price Charts,” March 9, 2026. https://oilprice.com/oil-price-charts/#Heating-Oil.

The above figure shows the increase in heating oil prices from about $2.60 per gallon when the military action started to about $3.60 per gallon when the data was recorded.

The figure below summarizes the soybean oil prices for the same time period.



Source: Futures TradingCharts.com, "Soybean Oil," March 9, 2026. https://futures.tradingcharts.com/chart/ZL.

For the same time period that petroleum prices increased, the price of soybean oil increased from 62¢ per pound to 68¢ per pound. Thus, while petroleum prices increased by 38%, soybean oil prices increased by 10%. Conversely, our estimate of the association between higher crude oil prices and impact on soybean oil prices in Chapter 10, which is over a longer time period, shows that for a 38% increase in crude oil prices, soybean oil prices are estimated to increase by about 25%. There is clearly a smaller association between petroleum price changes and soybean oil price changes for short-term price spikes compared to longer-term changes in these prices, and other agricultural feedstocks likely will respond similarly. To the extent that soybean and other feedstocks increase less than petroleum during petroleum price increases, there is a modest dampening effect.

Thus, when petroleum prices increase, because renewable fuel feedstock prices increase less than that of petroleum, the cost of the RFS program decreases.

We further discuss how renewable fuels can dampen fuel price shocks in RTC Section 9.1.2.

Comment:

A commenter said that EPA's analysis focuses only on the proposal's impact on crude oil, while ignoring that this rule increases dependence on imported feedstocks and the potential reduction of U.S. refining capacity. The commenter stated that EPA must meaningfully consider the impact of refining capacity loss on refined product markets and in specialized applications such as military- spec jet fuel. Other commenters said that independent refiners are critical to energy and national security as they provide much-needed diversity for the national fuel production capabilities. Commenters said absent meaningful reform, beginning with revisions to the proposed RVOs, these refiners may disappear forever, taking with them thousands of direct jobs along with the tens of thousands more that indirectly rely on these facilities, all while also greatly diminishing national energy security.

Response:

EPA has not ignored the potential impacts of the RFS volume requirements on the quantity of imported biofuels and biofuels produced from imported feedstocks in this rule. First, we note that by diversifying the source of transportation fuel used in the U.S., biofuels—including imported biofuels—can positively impact the energy security of the U.S.[185] We recognize, however, that imported biofuels and biofuels produced from imported feedstocks generally provide fewer benefits to rural economic development in the U.S. than biofuels produced in the U.S. from domestic feedstocks. EPA projects that the volumes we are finalizing in this rule could be met entirely with biofuels produced in the U.S. at existing renewable fuel production facilities. While we project that some imported feedstocks will continue to be used to produce biofuels (particularly BBD), we expect that due to the current structure of the 45Z credit, biofuels produced in the U.S. from North American feedstocks will generally be advantaged over imported biofuels and those produced from feedstocks outside of North America. Further, while EPA is not finalizing the proposed IRR provisions in this rule, we have stated our intention to finalize such provisions starting in 2028. These provisions, when finalized, will further support the use of domestic biofuels and feedstocks and will provide strong support for further investment in domestic production of biofuels and feedstocks.

To the extent that the RFS program does displace petroleum fuels, we have concluded based on a study by McKinsey and Co. that U.S. refinery production would only decrease by half of the displaced petroleum demand.[186] U.S. refineries typically produce refined fuels at a lower cost than refineries elsewhere, thus, they are less likely to shutdown than nondomestic refineries. Instead, the U.S. will otherwise import less, or U.S. refineries will increase their exports. As a rough estimate, for a given decrease in refined product demand, decreased U.S. refinery production would account for about half of that decrease in petroleum consumption, while for the other half of the decrease refiners would continue to produce gasoline and diesel fuel and either imports would decrease, or that refinery production would be exported.[187]

One conclusion from the McKinsey study is that as U.S. petroleum demand decreases, U.S. refinery production will not shut down at the same rate, thus, the U.S. refining system becomes increasingly more capable of supplying the U.S. market.

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[185] See RIA Chapter 6 for a further discussion of the projected impacts of this rule on energy security.
[186] McKinsey & Company, "Refining in het energy transition through 2040," October 2022. https://www.mckinsey.com/industries/oil-and-gas/our-insights/refining-in-the-energy-transition-through-2040.
[187] "Estimate of the impact of decreased petroleum consumption on US refinery production based on a study by McKinsey and Co.," available in the docket for this action.

Another conclusion from the McKinsey study is that refineries which produce multiple products, such as refineries which co-produce feedstocks for the petrochemical industry (*i.e.*, aromatics, propylene), tend to remain operating due to the diversity of products they produce. Thus, refineries that produce the military-spec jet fuel, which could be considered a specialty product, are more likely to keep operating as petroleum demand decreases due to the diversity of their product slate.

While some refineries permanently shut down, which means that their labor force must look elsewhere for employment, some refineries have chosen to convert some of their refining assets to produce renewable diesel fuel. The following table lists the refineries which have partially or completely converted their refineries to produce renewable diesel fuel.

Refining Company	Location	Capacity (million gallons per year)
BP Products	Blaine, WA	66
CVR Energy Inc.	Wynnewood, OK	100
Chevron	El Segundo	31
HF Sinclair	Artesia, NM	125
HF Sinclair	Cheyenne, WY	90
HF Sinclair	Sinclair, WY	117
Kern Oil Refining	Bakersfield, CA	6
Marathon Petroleum	Dickinson, ND	184
Marathon Petroleum	Martinez, CA	260
Montana Renewables	Calumet, MT	175
Phillips 66	Rodeo, CA	120
World Energy	Paramount, CA	42

The conversion of refineries to renewable diesel production facilities preserves some of their capital assets and also provides the opportunity to maintain some or much of the same workforce which was employed at the petroleum refinery. For the total increased volume of renewable fuels caused by the final volumes, we estimate the number of jobs created, which is described in RIA Chapter 9.1 and RTC Section 9.1.7.

Comment:

A few commenters expressed concern about uncertainty regarding the volume of gasoline and diesel that EPA will exempt through SREs, given recent court decisions and the potential that EPA will reallocate exempt volumes by adjusting the percentage standards. The commenters stated this creates an extra burden on non-exempt parties, even if some costs are passed on to consumers, and that lowering program costs by 55% would alleviate this burden and lower consumer costs. One of the commenters said that merchant refiners that do not blend fuel face the same struggle as small refiners because they do not generate RINs and are left to buy RINs on the open market.

Response:

We acknowledge that there is some level of uncertainty regarding SREs in future years as SRE decisions are made on a case-by-case basis and depend on the facts in each year. We recognize that reallocating exempted volumes, whether prospectively or retrospectively, increases the obligations for non-exempt obligated parties. However, we believe that reallocation is necessary to preserve the intended effect of the renewable volume requirements, as failure to reallocate the exempted volumes would result in less demand for renewable fuels.

We also recognize that EPA's decision to finalize an implied 15-billion-gallon conventional renewable fuel volume requirement for 2026 and 2027 will likely result in higher D6 RIN prices relative to setting the implied conventional RIN volume at or below the E10 blendwall. As discussed in Preamble Section III and RIA Chapter 7, we expect that the 15-billon-gallon conventional renewable fuel volume requirement is justified as it will continue to provide incentives for investment in infrastructure necessary to increase the availability and sales of higher-level ethanol blends. Increased availability of higher-level ethanol blends could result in increased ethanol production and consumption, which has the potential to provide many domestic benefits. Finally, while we recognize that higher D6 RIN prices will increase the cost of acquiring RINs for obligated parties, we do not expect that these prices will negatively impact refiners. Rather, we find 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.[188] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs.

[188] 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 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.

9.2 Environmental Impacts and Considerations

9.2.1 Climate Change

Comment:

Numerous commenters stated in various ways that EPA should update or modify our lifecycle greenhouse gas analysis of various fuel pathways using different tools, data, and/or assumptions. Commenters provided diverse justifications for why EPA should do so. Requests for changes to our LCA methodology by commenters included incorporating accounting for carbon capture and storage, incorporating consideration of climate-smart agriculture, and updating electricity, hydrogen, and RNG accounting methods. Commenters argued these changes would expand pathway opportunities, incentivize on-farm sustainability practices, and replace current values with inputs they considered out of date.

Response:

EPA did not propose and is not finalizing in this rulemaking any updates to the methodology for assessing lifecycle GHG emissions under the RFS program, nor is EPA reassessing any lifecycle determinations for existing crop-based fuel pathways under the program. EPA stresses that the analysis of climate change impacts it conducts pursuant to CAA section 211(o)(2)(B)(ii) and the lifecycle greenhouse gas assessments it conducts for the purpose of determining whether biofuels qualify as renewable fuel under the RFS program are, despite having methodological similarities, separate sets of analyses. For this reason, comments on EPA's methodology for assessing lifecycle GHG emissions under the RFS program are summarized in Section 12.3 ("Beyond the Scope") and are not otherwise addressed in this document.

Comment:

Several commenters referred to a letter issued by EPA in January 2025 and stated that EPA has confirmed that 45ZCF-GREET is compliant with CAA and RFS provisions on biofuel lifecycle analysis.

Response:

While we are not addressing the methodologies for assessing lifecycle GHG emissions under CAA section 211(o)(1)(H) in this action, we would like to clarify one matter regarding the scope of the January 2025 letter referenced by several commenters. As described in that letter, EPA has interpreted CAA 211(o)(1)(H) to require consideration of, *inter alia*, significant indirect emissions from land use, crop, production, and livestock.[189] The letter then confirms that the 45ZCF-GREET model "includes consideration" of these three particular categories of emissions. It does not purport to speak to the any other aspect of 45ZCF-GREET vis-à-vis the RFS program's statutory requirements.

[189] Letter from Joseph Goffman, EPA, to Aviva Aron-Dine, U.S. Department of Treasury, January 8, 2025.

Comment:

Some commenters pointed to EPA's climate change analysis for the current and prior Set Rules, which they claimed raised questions as to whether crop-based biofuels meet the statutory emissions reduction thresholds. Several commenters specifically point to the modeled scenarios for the climate change analysis conducted for this rule to argue that crop-based biofuels generally and oilseed oil-based biofuels in particular may not meet emissions reductions thresholds for categories of renewable fuels defined in the CAA.

Additionally, some commenters recommended that EPA break out results in the climate change analysis for individual crop-based fuels to allow for comparison and demonstrate emissions reductions specific to corn starch ethanol, similar to the level of disaggregation that occurs in evaluations of secondary product-based fuels.

Response:

While we are not addressing the methodologies for assessing lifecycle GHG emissions under CAA section 211(o)(1)(H) in this action, we would like to clarify that the climate change analysis conducted for purposes of CAA section 211(o)(2)(B)(ii)(I) and analyses conducted for fuel pathway threshold determination under CAA section 211(o)(1)(H) serve substantially different purposes with differing methodological considerations.

Scenarios presented in the climate change analysis for this rule combine volumes for multiple crop-based fuels simultaneously. Interactions between fuel markets, the different feedstocks needed to produce these fuels, and the land needed to grow these feedstock crops make it inappropriate to attribute a subset of the land use or emissions impacts under the modeling conducted for this rule to any individual fuel pathway. Because of these interactions, results in combined volume target scenarios are likely to differ significantly from scaled and summed results from scenarios representing individual fuel pathways—the type of modeling that would be necessary for the purpose of lifecycle GHG threshold determination. Furthermore, for these reasons we are unable to disaggregate the impacts of individual crop-based fuels within the GCAM and GLOBIOM modeling results, as a commenter suggested.

Additionally, there are fundamental methodological differences in the appropriate scope and baseline of comparison that reflect the different statutory requirements and contexts for climate change analysis conducted for purposes of CAA section 211(o)(2)(B)(ii)(I) and analyses conducted for fuel pathway threshold determination. For example, statutory emissions reductions for categories of renewable fuel under the RFS program are defined relative to emissions associated with production and use of gasoline or diesel that was produced in 2005. Use of this fossil fuel comparative baseline is specifically required for consideration of lifecycle GHG emissions for the purpose of pathway approval, but is not aligned with the climate change analysis conducted for purposes of CAA section 211(o)(2)(B)(ii)(I), which is intended to assess the actual impacts of volume standards in the years in which they are in effect. Additionally, GHG emissions estimates in RIA Chapter 5 derived from GCAM modeling are further distinct methodologically from EPA's analysis of individual pathways because GCAM endogenously represents energy sector impacts and includes oil rebound, whereas all completed pathway lifecycle GHG assessments under the RFS program have compared lifecycle GHG emissions estimates with baseline fuels on a one-for-one energy equivalent basis.

For these reasons, we caution against imputing crop-based fuel pathway LCA results based on the modeling presented in the climate change analysis for this rule as that would not be a proper use of these results. We do not do so in the RIA for this final rule.

Comment:

Several commenters recommended that EPA include GREET and GTAP-BIO models in its climate change analysis, arguing that the combination of GREET and GTAP-BIO provides comprehensive coverage of a fuel's lifecycle across both supply chain and market-mediated emissions. Commenters also disputed EPA's rationale for excluding GREET/GTAP-BIO in its climate change analysis. Some commenters stated that estimates of land use impacts of biofuels derived from GTAP-BIO are more closely aligned with historical data than comparable modeling conducted with GCAM or GLOBIOM. Some commenters argued that land use change estimates in these models are not supported by real-world data, pointing to stability in U.S. ethanol production, corn used for ethanol, corn production in total, and corn acreage over the past ten years. One commenter suggested that EPA include model accuracy and validation using empirical data in its model selection criteria and leverage a risk-based approach that relies on empirical data to validate the results from multi-model ensembles.

Response:

We agree with commenters that including estimates from additional models in our climate change analysis better represents the diversity of results and uncertainty across modeling methods. For this reason, while we were unable to conduct new modeling of comparable combined volume scenarios using the GTAP-BIO model for this final rule, we have included an additional assessment based on emissions factors derived from GTAP-BIO modeling that are distributed with R&D GREET. Reasons for this addition and caveats for consideration of these estimates alongside the GCAM and GLOBIOM estimates are discussed in RIA Chapter 5.1.

Modeling of land use and agriculture sector impacts of future biofuel policies using the three economic models presented in this final rule is necessarily compared against forward-looking counterfactual scenarios in which biofuel policies are absent (*i.e.*, the No RFS Baseline). Commenters suggest EPA assess the modeled results using empirical data, which are necessarily historical. However, historical data reflect extant biofuel policies at the time and thus are of limited utility in assessing impacts of future biofuel policy relative to a forward-looking counterfactual scenario. However, we agree with commenters that validating economic modeling tools capable of assessing land use change impacts of biofuels, to the extent possible, would be a valuable area for future research. At this time, we are unaware of any evaluation studies comparing the relative validity of these or other similar modeling tools. This type of scientific work would be a necessary precursor to confirming or denying the assertions made by the commenters regarding the validity of these tools. The comments summarized above did not present suitable evidence of this type which could be used to support such an assessment. As such, we conclude there is currently no adequate basis for determining whether one of these tools is more appropriate than the others for this type of impact assessment.

Additionally, we note that the updated methodology for conducting the climate change analysis described in RIA Chapter 5 does not constitute a change in position from our previous analyses. The updated methodology is simply a different way of estimating net greenhouse gas emissions associated with the RFS final volume standards. While in the past we have used different methodologies to derive estimated ranges of emissions, in this rule we use models to estimate ranges of emissions. The Agency has not reversed its prior view that it is appropriate to consider climate change impacts by assessing the net greenhouse gas emissions associated with the production and use of the biofuels that comprise volumes under consideration. Nor is it rescinding a prior action.[190] Again, the updated methodology is simply a different way of arriving at the emissions estimates. And even if the updated methodology *was* a change in position, EPA has provided ample compelling reasons for updating our methodology in RIA Chapter 5.[191]

Where EPA has changed position in this rulemaking is in its weighing of the climate change impacts factor vis-à-vis the other statutory factors in determining the volumes in this final rule. This change is discussed in Preamble Section III.E.5.

Comment:

One commenter stated that it is inappropriate for EPA to consider emissions impacts outside of the United States from activities that are not directly regulated by EPA. Another commenter expressed skepticism about EPA's reliance on economic models to quantify market-mediated effects of biofuel production and use, stating that EPA should use consistent assumptions and system boundaries for all fuels, including petroleum-based fuels that are being displaced. Other commenters noted that conducting consequential analyses for assessing RVO climate impacts is aligned with NASEM recommendations on assessments of biofuel impacts,[192] and that an assessment of induced land use change impacts is an integral component of a consequential analysis of biofuels.

Response:

The purpose of the analysis of the statutory factors assessed when setting volume standards under the RFS program is to assess the impacts that are likely to occur as a *consequence* of those standards. For many of the assessed factors, impacts arise from actions of, and are felt by, unregulated parties. That does not exclude these likely consequences of an action from consideration in our assessment of the statutory factors presented in the RIA.

[190] See *FDA v. Wages and White Lion, Invs., L.L.C.*, 604 U.S. 542, 569-570 (2025).
[191] Id.
[192] National Academies of Sciences, Engineering, and Medicine. 2022. Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels. Washington, DC: The National Academies Press. https://doi.org/10.17226/26402.

As discussed in RIA Chapter 5, we believe consequential analyses using economic models that integrate as many relevant economic sectors as possible constitute the most appropriate method of assessing the potential GHG emissions impacts of policies influencing the production and use of biofuels. This method aligns with findings in EPA's 2023 Model Comparison Exercise Technical Report and recommendations made in the NASEM report on methods of assessing impacts of biofuels, as noted by several commenters.

Comment:

Several commenters stated that EPA misestimated the potential ILUC impacts associated with the proposed volume scenarios. Different commenters asserted that EPA's assessments in the proposal either under- or over-estimated GHG emissions impacts of the volume standards, citing different studies of agriculture and land use impacts of biofuels to support their arguments. Some commenters recommended that EPA reconsider how it incorporates ILUC estimates and/or clarify that the presented analysis represents a conservative estimate of climate benefits. These commenters contend that the assumptions employed to classify land use and land available for conversion to biofuel feedstock production led to an overestimation of land use change stimulated by the proposed volume scenarios and therefore overestimate GHG emissions from indirect land-use change associated with the proposed volumes. One commenter suggested that a different body of evidence refutes the idea that the RFS program has stimulated the conversion of natural, intact grasslands or forests to cropland in the United States, suggesting that any trends in cropland expansion are driven by unrelated market and sociological factors. Conversely, other commenters argue that EPA's analysis does not fully consider or underrepresents land-use conversion resulting from biofuel production.

Response:

As discussed in RIA Chapter 5 and reflected in EPA's prior work in the literature review of biofuel lifecycle analyses conducted for the Set 1 RIA, there is substantial and irreducible uncertainty in the potential future impacts on GHG emissions of changes in biofuel consumption levels. However, as discussed in RIA Chapter 5, we believe using a multi-model approach is the best available method to characterize that uncertainty and illustrate the range of potential outcomes. While we believe that some of the historical data cited by commenters are not directly relevant to the counterfactual comparative analysis of climate change we conducted for the purposes of CAA section 211(o)(2)(B)(ii)(I) (as we explain in other comment responses in this section), we believe the range of comments and studies referenced by commenters broadly reflect the uncertainty we have identified in the literature on biofuel LCA. For this reason, we believe that including additional assessments, rather than fewer, is the most informative approach to characterizing the potential emissions of the impacts of the standards. Therefore, as discussed in other responses within this section, we have included additional estimates in the final rule based on GREET and GTAP-BIO in RIA Chapter 5.

Comment:

A commenter stated that, as a partial equilibrium model designed to primarily cover the energy sector, GCAM's modeling of the agricultural sector and its relationship to the clean fuels sector is too underdeveloped to address potential induced land use change questions. The commenter stated that GCAM currently only specifies three biodiesel pathways (soybean oil, palm oil, and jatropha), while all other oilseeds and waste oils are not explicitly represented in the model.

Response:

The commenter inaccurately describes the representation of biofuel commodities and the agricultural sector in GCAM. The representation of crops in GCAM is comparable to the other two economic models used for the climate change analysis in this final rule; GCAM represents global consumption, production, and trade of 14 major crop categories, including corn, soy, and rapeseed, while GLOBIOM and GTAP-BIO represent 18 and nine distinct crop commodities respectively. A comparison of commodities represented in these three models was presented in Table 5.1-1 of EPA's 2023 Model Comparison Exercise report.[193] The version of GCAM used in the climate change chapter of this rule represents major sources of vegetable oil that are used for biodiesel production, including soybean oil, rapeseed oil, palm oil, and an aggregate category representing all other vegetable oils. GCAM represents production, trade, and consumption of these oils for food and industrial uses, and production of biodiesel from these oils and trade and consumption of the finished biofuel commodities differentiated by feedstock oil and finished fuel type. Additional information on GCAM's representation of key markets for biofuel impacts analysis is provided in RIA Chapter 5.4.

Comment:

A commenter stated that GCAM's representation of animal feed should be further developed to represent livestock dietary requirements fulfilled by different agricultural products and byproducts.

Response:

We agree with the commenter that additional detail in GCAM's representation of animal feed requirements could be a valuable development for assessing biofuel impacts on agriculture sectors and land use. We will continue to consider future developments in GCAM and other analytical tools where appropriate for future analyses.

Comment:

Commenters expressed concerns about GCAM's methodology for land allocation, which uses logistic functional form equations that they say tend to be highly sensitive. Commenters questioned GCAM's land nesting structure, particularly the distinction between "other arable land" and "cropland" in the figures presented in the DRIA and assumptions on land available for conversion.

[193] EPA, "Model Comparison Exercise Technical Document," EPA-420-R-23-017, June 2023.

Response:

The logistic functions used in GCAM's economic logic are tuned with multiple parameters that affect the sensitivity of the represented market to changes in prices. These parameters for each market are tuned to reflect the best available historical data and information at the time of implementation and are updated over the course of ongoing GCAM model development. Markets in GCAM can and do range from highly responsive to price signals to totally inelastic depending on the parameterization. Additionally, we note that the logistic function form used in GCAM results in *decreasing* implied elasticities with respect to cropland expansion (*i.e.*, the more cropland expands, the harder additional expansion becomes). This real-world phenomenon is well-understood in the economic literature, but is not well represented with static elasticity parameters used by many other models, as these parameters assume that all cropland expansion is equally easy/difficult at a given cost of conversion. In this way, GCAM's mathematical structure provides a useful complementary frame to the static elasticity structures used by GLOBIOM and GTAP-BIO. Additional information on the mathematical logic used to represent land allocation can be found in GCAM's online documentation (see https://jgcri.github.io/gcam-doc/land.html) and in documentation for recent updates to the GCAM core model.[194]

GCAM's land nesting structure is explained in the online documentation cited above. As depicted in the figures in that documentation, "other arable land" and the land used for active production of each of the crop categories represented in GCAM are all contained within a node called "cropland" in the model's land nesting structure. This representation means that substitution of land between different crops and between actively productive cropland and "other arable land" is more elastic than changing from land categories in other nodes to crop production. The figures in the DRIA depict "Cropland" – which represents the aggregate area used for active crop production – and "Other Arable Land" distinctly in order to illustrate the extent to which additional agricultural commodity production comes from use of what was previously "other arable land."

We agree with the commenter that representation of availability and unavailability of land for conversion to other uses can have a material impact on biofuel modeling, a finding which has been explored in detail in the academic literature.[195] GCAM's default representation of "protected" land—land that is unavailable for conversion to other uses—is described in the model documentation cited above, and is based on published land suitability levels and land protection categories defined by the International Union for Conservation of Nature. We welcome continued consideration and refinement of these important assumptions across the modeling community working on impact assessments for biofuels.

[194] Global Change Analysis Model (GCAM) Core Model Proposal #393, available at http://jgcri.github.io/gcam-doc/cmp/393-AgLU_Parameters_Update.pdf

[195] Plevin, Richard J., Jason Jones, Page Kyle, Aaron W. Levy, Michael J. Shell, and Daniel J. Tanner. 2022. "Choices in land representation materially affect modeled biofuel carbon intensity estimates." Journal of Cleaner Production 349 (March): 131477. https://doi.org/10.1016/j.jclepro.2022.131477.

Comment:

Commenters expressed concern that GCAM responds to volume scenarios with significant increased U.S. imports of biofuels that would otherwise be consumed in other regions, which may not reflect policy support for biofuels in those countries.

Response:

The commenter highlights a key difference between the models presented in RIA Chapter 5; while all three economic models used in our climate change analysis in the final rule can meet the biofuel demand targets in the policy scenario through increased feedstock imports, only GCAM represents trade in biofuels, thus allowing for the targets to be met partially through increased imports of biofuels. We agree with the commenter that development of alternative scenarios which represent biofuel policies in non-U.S. regions could provide useful additional information. While we were unable to conduct new modeling for the final rule, we will consider alternative scenario designs as appropriate for future assessments under the RFS program.

Comment:

A commenter criticized GCAM for undervaluing the benefits of biofuels by assigning an emissions factor for petroleum that is significantly lower than other widely accepted estimates. The commenter stated that GCAM uses an emissions factor for refined petroleum of roughly 72 gCO_2e/MJ, while GREET estimates cited by EPA are roughly 93 gCO_2e/MJ and 91 gCO_2e/MJ for gasoline and diesel respectively.

Response:

It appears that this comment improperly compares an emissions factor identified in GCAM, which represents only combustion emissions for refined oil, with emissions factors from GREET for gasoline and diesel, which represent the full lifecycle emissions of the fuel, including oil extraction, transport, refinery inputs, and end use combustion. For comparison, the version of GREET used in the climate change analysis in the proposal estimates combustion emissions for gasoline and diesel as 73 gCO_2e/MJ and 76 gCO_2e/MJ respectively.[196] These appear to be sufficiently close to the coefficient cited by the commenter that we believe it is appropriate and reasonable, especially considering that the comparison is not apples-to-apples. The GCAM coefficient is an average combustion coefficient for all refined petroleum products (*i.e.*, jet fuel, propane gas, bunker fuel, etc., in addition to gasoline and diesel fuel), so it would not be expected to be identical to a gasoline- or diesel-specific coefficient. Energy inputs and associated emissions are represented endogenously in GCAM for oil extraction, transport, and refining, and are therefore appropriately not represented in the emissions factor cited by the commenter.

[196] See DRIA Table 5.1.2.4-1.

Comment:

A commenter argued that EPA should not use linear interpolation with GCAM results as a method for estimating cumulative impacts of RFS volumes because the mathematical form of land competition in GCAM is non-linear.

Response:

We disagree with the commenter that our use of linear interpolation to assess cumulative impacts, including over years not represented in GCAM, is inappropriate or misaligned with the structure and assumptions of the model. GCAM's economic logic uses logistic functions that are non-linear with respect to commodity prices. However, GCAM does not make any universal assumptions about how markets might develop in years that are not solved (*e.g.*, GCAM solves markets and outputs are available for 2030 and 2035, but there are not explicit or implicit assumptions about activity in represented sectors in the years 2031-2034). A notable exception is that GCAM outputs include estimated annual land use change emissions. This accounting is done to represent the non-linear (with respect to time) emissions associated with soil carbon fluxes following a change from one land use type to another. Notably, however, the reported annual land use change emissions estimates from GCAM are based on linear interpolation of actual land areas between time steps. As an illustrative example, if 100 hectares of land transition from one use to another between 2025 and 2030 in a GCAM simulation, then the annual land use change emissions accounting reported by GCAM assumes that 20 hectares transition in each year from 2026 through 2030. The non-linear loss or uptake of soil carbon on those 20-hectare parcels is then tracked and accounted for in annual land use change emissions outputs. As an additional example, drawdown of fossil resources is also estimated with an assumption of linear interpolation of the quantities in years between timesteps.

These examples illustrate that many GCAM outputs, including several related specifically to land cover and land use change, are based on assumptions of linear interpolation of change in physical quantities between model timesteps.

Comment:

Commenters noted that the endogenous representation of energy sector impacts in GCAM resulted in substantially lower displacement of fossil fuels when compared to GLOBIOM-based estimates, in which EPA assumed one-for-one energy equivalent displacement of fossil fuels. Based on this observation, several commenters criticized the use of GLOBIOM for estimating climate change impacts of the proposed standards because GLOBIOM does not represent the "rebound effect"— the price-induced increases in oil demand partially theoretically offsetting the renewable fuel displacement effect—and therefore may lead to an overestimation of emissions reductions from the standards.

One commenter recommended that EPA adjust GLOBIOM-based estimates to account for market-mediated energy sector impacts by combining emissions estimates from land and agricultural sector impacts in GLOBIOM with energy sector impacts in GCAM. Other commenters argued that fossil fuel displacement effect in GCAM results was unrealistically low and that this biased the GCAM-based estimates towards greater emissions impacts of biofuels. One commenter stated that the emissions effects of oil rebound should not be considered in climate change analysis for RIA under the RFS.

Response:

The purpose of EPA's analysis of the statutory factors assessed when setting volume standards under the RFS program is to assess the impacts that are likely to occur as a consequence of those standards. Thus, we agree with commenters that argue consideration of impacts of biofuel policies on energy markets and oil consumption are within the scope of appropriate analyses in the assessment of impacts of this rule.

While we agree with commenters that there would likely be some non-zero rebound effect, we are unable to assess the magnitude of the effect with enough confidence to apply a single rebound adjustment to our one-for-one oil displacement assumption used with models that don't internally represent energy market impacts. Thus, the central estimates presented in RIA Chapter 5.2 do not include post-hoc adjustments to represent oil rebound. However, we agree with commenters that illustrating the sensitivity of emissions estimates to different magnitudes of rebound provides valuable information about the uncertainty of GHG emissions associated with the final volumes. For this reason, in this final rule we include sensitivities in RIA Chapter 5.3 that present GHG emissions estimates under a range of scenarios representing different magnitudes of oil rebound. See RIA Chapter 5.3 for more information about these sensitivities and uncertainty in the oil rebound response to increasing use of biofuels.

Comment:

While numerous commenters commended EPA on the advancements in modeling associated with the proposed RFS climate change analysis, other commenters expressed concerns about EPA's proposed approach to address uncertainty in the modeling it conducted in the DRIA. They argued that using both GCAM and GLOBIOM and synthesizing their output does not add additional certainty to the results, as the models have vastly different origins with distinct assumptions on market structure and response based on divergent datasets. Other commenters recommended that EPA transparently document uncertainties in modeling tools. They welcomed EPA's sensitivity analysis of some parameters in DRIA Appendix 5-A but noted that the analysis does not include consideration of the Shared Socioeconomic Pathways that predict factors like GDP.

Response:

As discussed in RIA Chapter 5, EPA includes multiple models in the assessment of potential climate impacts of the Analyzed Volumes precisely because doing so better characterizes uncertainty by representing a range of different mathematical approaches and structural representations of the key market sectors, economic relationships, and biophysical attributes and phenomena under evaluation. As we described in the DRIA and discuss in RIA Chapter 5, as well as in other portions of this RTC section, it is presently highly uncertain which of these approaches and structures is most appropriate for this type of analysis. Absent scientific clarity regarding the most appropriate approach and model structure, representing a range of plausible and well-published options best covers the breadth of potential outcomes. For this reason, we have included additional estimates in the final rule relative to the analysis conducted for the NPRM. These estimates are based on an additional modeling framework which incorporates economic modeling conducted using GTAP-BIO with other supply chain modeling in R&D GREET.

We agree with commenters that assert the importance of assessing and documenting uncertainty in the modeling used to evaluate climate change impacts of the Analyzed Volumes. For this reason, we conducted the parametric uncertainty analysis in GCAM which was presented in DRIA Appendix 5-A and is maintained in the final rule in a memo to the docket. While the monte-carlo sensitivity analysis conducted with GCAM did include adjustments to population, we agree that additional sensitivities into macro-economic indicators in GCAM and the other models considered would be valuable. We will continue to assess what sensitivity modeling would be most informative in future actions, given resource and timing constraints. Additionally, based on comments received, we have included additional sensitivity analyses illustrating the potential impact that oil market rebound could have on emissions estimates (see RIA Chapter 5.3).

Comment:

A commenter argued that EPA's climate analysis underestimates the GHG emissions benefits of RNG by comparing RNG emissions to natural gas rather than diesel fuel.

Response:

As discussed in RIA Chapter 2.1.2.1, EPA projects that future growth in RNG use for transportation will predominantly coincide with new CNG/LNG vehicles being adopted (thus displacing diesel vehicles). However, the climate change analysis assesses the GHG emissions impacts of the Analyzed Volumes relative to volumes of renewable fuels projected to be consumed under the No RFS Baseline. Relative to current volumes used in 2025, the Analyzed Volumes in 2026 and 2027 represent a modest increase in RNG use, while RNG volumes under the No RFS Baseline Scenario represent a relatively substantial decline; greater than 90% of the assessed difference in RNG volumes between the Analyzed Volumes and No RFS Baseline Scenario represents a decrease relative to volumes currently used in 2025. Thus, fossil natural gas is the appropriate baseline for the majority of volumes analyzed because under a scenario in which RNG use declines, existing vehicles would presumably continue operation using fossil natural gas as fuel. To the extent that the final RVO standards result in expansion of CNG/LNG vehicles, a diesel baseline may be appropriate for a portion of the volumes considered. However, as discussed above, growth relative to 2025 volumes represents less than 10% of the assessed differences in volumes. Thus, while our assessment of GHG emissions reductions from RNG use could be considered a conservative estimate for this portion of the volumes, the impact on overall GHG emissions estimates would be limited.

Comment:

A commenter recommended disaggregating crop-based fuel emissions impacts estimates from emissions impact estimates of secondary product-based fuels, arguing that the aggregated total of these two categories obscures the relative uncertainty and range of potential impacts of crop-based fuels.

Response:

We thank the commenter for their suggestion. Table 5.2-1 in the RIA presents the cumulative emissions estimate for each modeling framework, disaggregating estimates for crop-based fuels and secondary product-based fuels. Additionally, these estimates are provided in more detailed disaggregation in a spreadsheet in the docket.

Comment:

Multiple commenters stated that ethanol, crop-based biofuels, and the RFS program in general reduce GHG emissions. Several commenters specifically state that bioethanol and canola oil BBD provide climate benefits. Commenters state that EPA's findings confirm emissions benefits of biofuels. Several commenters state that EPA's methodology for the proposed rule represents a meaningful improvement over the methodology use to assess climate change impacts of the 2010 RFS2 rule.

Response:

We appreciate commenters' acknowledgement that the modeling conducted for the climate change analysis of this final rule represents an advancement in methods for quantifying potential impacts of volume standards under the RFS program. We agree that the estimates presented show the potential for reductions in GHG emissions from these fuels.

9.2.2 Air Quality

Comment:

A commenter argued that the air quality impacts of corn ethanol, biodiesel, and renewable diesel are plainly harmful, despite EPA's attempt to frame the results of its air quality impacts assessment as "ambiguous or mixed." The commenter, along with another, noted that compared to the No RFS Baseline, EPA predicts that the ethanol, biodiesel, and renewable diesel fuels associated with the proposed volumes will result in hundreds of net tons of CO, NH_3, NO_X, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions. While EPA does predict some air pollution reductions from the production of biogas CNG/LNG, the commenter argued that these reductions cannot be used to discount the harmful air pollution that will result from the volumes proposed for BBD and ethanol. Commenters stated that these results clearly suggest that lower BBD and conventional renewable fuel volumes would be significantly better for air quality, and it is disingenuous to call these impacts "ambiguous." Another commenter said that given that EPA's RFS program contributes to deterioration of ambient air quality, EPA should not propose increases to the RVO for 2026 and 2027.

One commenter noted that EPA's statement that growth in cellulosic biofuel production can occur "with little to no impact on other environmental factors, such as air or water quality" is contradicted by EPA's own analysis in the DRIA showing air quality benefits of using renewable natural gas instead of fossil natural gas and to replace diesel vehicles.

One commenter argued that EPA's air quality analysis failed to consider the geographic heterogeneity of the emissions impacts from ethanol and petroleum. The commenter stated that ethanol's tailpipe emissions reductions are most beneficial in high-traffic areas such as urban centers, and that the public health benefits from reducing emissions in high-risk urban centers are expected to be greater than the costs in emissions in low-density rural areas. In contrast, another commenter said that increased infrastructure associated with biofuel production in rural areas poses risks to the air quality and environmental health of their reservation and surrounding lands.

One commenter noted that EPA states that as the biofuels industry matures, increases in emissions of air pollutants from the production of biofuels are likely to become smaller without providing any rationale or explanation for this statement. Another commenter said that there have been measurable reductions in toxic aromatics, particulate matter, brown carbon/carbon monoxide, and other pollutants in ethanol plants.

Response:

With regard to EPA's assessment of the air quality impacts as "ambiguous or mixed," EPA believes this is an accurate statement of the results of our analysis. As presented in RIA Chapter 4.1.2.1, our quantitative analysis of biofuel production emissions determined increased emissions of some air pollutants associated with some biofuels and decreased emissions of some air pollutants with some biofuels. These findings of increased emissions in some cases and decreased emissions in others are not meant to imply that such emissions offset one another, but rather demonstrate that impacts may vary across geography.

However, as discussed in Chapter 4.1.3, detailed inventories of emissions and photochemical air quality modeling would be necessary to accurately understand the spatial impacts of biofuel use. Public health benefits are a result of the location of the emissions as well as the magnitude and species of pollutants emitted. Some pollutants are formed secondarily and transported long distances, and determining where public health benefits would occur is not possible without photochemical air quality modeling. There could be areas with localized air quality improvements as well as areas with localized worsening of air quality as a result of the proposed volumes. Additionally, the spatial resolution of air quality modeling data (12 km by 12 km grid cells) are not sufficient to capture very local impacts associated with the proposed volumes.

We did not evaluate trends in biorefinery emissions over time as part of the air quality impacts analysis. We have provided clarification and citation in the RIA on our statements on future biofuel production emissions with industry maturity and appreciate the identification of the unclear language of the DRIA.

Comment:

Several commenters disagreed with EPA's assessment of the impacts of transporting biofuels or of the use of biofuels on end-use/vehicle emissions. A commenter questioned whether EPA considered the reduction of emissions associated with vehicle emissions in considering air quality impacts, noting that EPA has found that "[r]eplacing traditional diesel or gasoline with RNG can significantly reduce emissions of nitrogen oxides and particulate matter, resulting in improved local air quality."

Additionally, one commenter argued that EPA's draft analysis incorrectly concluded that the rule would "not have a significant impact" on tailpipe emissions without discussing the substantial benefits of ethanol-blended fuels. The commenter stated that EPA failed to adequately acknowledge the tailpipe emissions reductions of fuel blends with higher ethanol content compared to fuels with lower ethanol content. The commenter cited multiple studies showing that ethanol boosts octane in fuel and results in lower tailpipe emissions compared to other octane-boosting fuel additives such as methyl tert-butyl ether (MTBE), lead, and aromatics.

A commenter stated that biodiesel provides benefits for air quality and its emissions significantly outperform petroleum-based diesel, and that EPA acknowledged that. However, the commenter noted that EPA found no emissions impacts (*i.e.*, no reductions) when using renewable diesel in lieu of petroleum diesel because they are "chemically analogous." In contrast, another commenter highlighted studies finding increased emissions of NO_X, CO, and hydrocarbons from vehicles using biodiesel in comparison to fossil diesel and low-sulfur diesel.

One commenter also noted that EPA's inconsistent use of E10 as the fuel of comparison when analyzing tailpipe emissions and E0 as the fuel of comparison when analyzing transport emissions improperly understates the benefits and overstates the disbenefits of the proposal.

Response:

In the air quality impacts analysis for Set 2, EPA evaluated the emissions impact from transporting biofuels and end use of biofuels qualitatively and did not estimate quantitative emissions impacts. Additionally, only the impact of biofuels transport or end use due to the volumes of biofuels finalized in this rulemaking were considered, and not general emissions impacts of biofuels in comparison to fossil or petroleum-based fuels. This analysis also did not evaluate differences in emissions of criteria or hazardous air pollutants from vehicles utilizing renewable natural gas in comparison to fossil fuels like gasoline or diesel fuel.

In evaluating the impacts of the Set 2 Final Volumes on emissions from vehicles utilizing biofuels, EPA disagrees with the conclusions reached by some commenters. Some commenters chose to selectively focus on individual studies or a subset of results from individual studies rather than the entirety of the literature. While some studies show biofuel use can potentially lead to reduced end use emissions for some air pollutants, other studies show biofuels can potentially lead to increased emissions of air pollutants. The end use emissions assessment reflects EPA's data and modeling of impacts from biofuel on vehicle emissions and is supported by EPA's analyses and comprehensive assessment of the literature. This includes a 2018 review of the range of published studies on the effects of fuel properties, including ethanol, on emissions.[197] Regarding the end use emissions of biodiesel, we appreciate the consideration of recent literature and identification of relevant studies on biodiesel emissions. EPA is currently examining the literature on this topic and will be considering what it implies for future updates to EPA's motor vehicle emissions model and emissions research needs.

With regard to the comments on EPA's use of E0 as the fuel of comparison in evaluating transport emissions, clarification has been added to Chapter 4.1.2.2 discussing emissions from the transport of biofuels. As the difference in the 2026-2027 ethanol volumes when compared to the No RFS baseline is greater than zero, emissions resulting from the transport of this additional volume of ethanol will result in an air quality impact; however, the text has been expanded to reflect the magnitude of this impact in RIA Chapter 4.1.2.2.

Comment:

Several commenters questioned EPA's methodology for determining emissions from the production of biofuels. One commenter criticized EPA's assessment of air quality impacts comparing ethanol, biodiesel, and renewable diesel to a "no-RFS baseline," calling it a false comparison. The commenter stated that EPA is not estimating biodiesel production to increase under the proposed volumes and the use of 1716 million gallons of biodiesel production used to determine potential emissions appeared arbitrary. The commenter stated they were unable to re-create EPA's emissions factors for biodiesel based on the limited information provided by EPA and also noted the lack of reference to biodiesel in the document cited in the DRIA. The commenter questioned how EPA was using higher emissions factors for biodiesel production for certain pollutants than for renewable diesel production, when biodiesel uses less energy to

[197] EPA, "Agency Response to Request for Correction of Information: Petition #17001, Concerning the EPAct/V2/E-89 Fuel Effects Study and the Motor Vehicle Emissions Simulator (MOVES2014) Developed by the USEPA Office of Transportation and Air Quality," August 31, 2018.

produce and uses the same feedstocks as renewable diesel. This commenter also stated that in contrast to the production of renewable diesel, the production of biodiesel produces little to no emissions of air toxics and that EPA recognized this difference in 2017 when noting air emissions from the production of renewable diesel would be similar to air emissions of a petroleum refinery. The commenter also questioned the biodiesel production emission factors in the DRIA given EPA's analysis of 175 biodiesel facilities in 2017 showed significantly less SO_2 and volatile organic compound (VOC) emissions.

Commenters noted that in Chapter 4 of the DRIA, EPA found that recent studies show that utilizing biogas results in an overall reduction of criteria air pollutant emissions compared to allowing the waste to decompose in a landfill or by natural composting or decomposition. However, one of the commenters said that EPA did not account for these avoided emissions in its quantitative analysis, stating that simply comparing modeled emissions to a "no-RFS" baseline does not accurately reflect the potential beneficial impacts of RNG production on air quality. The commenter also noted that RNG systems reduce odors from food wastes and manures, and reduce local criteria pollutants caused by the flaring of raw biogas.

Response:

In this analysis, EPA estimated emissions associated with the production of biofuels as a result of the RFS program rather than estimating emissions from all domestic production of biofuels. To do this, the emissions were estimated only for the difference in the biofuel volumes for the years covered in this rule (2026–2027) as compared to the No RFS Baseline. Therefore, the annual production of biodiesel may remain constant under the set volumes, but the difference in the estimated production compared to the No RFS Baseline volumes may be non-zero; in the 2026 estimation, the difference in the volume to the No RFS Baseline of biodiesel was 1,716 million gallons. For more information on how the No RFS Baseline volumes were determined, see RIA Chapter 2.1.

EPA has outlined the methodology used to calculate biofuel production emissions factors in RIA Chapter 4.1.2.1. Additional details were also provided in a technical memorandum to the docket, and calculations and results were made available in a docketed spreadsheet.[198] As stated in the DRIA, the analysis utilized CBI provided to EPA through EMTS that could not be disclosed publicly. As only 21 biodiesel production facilities generated RINs and also reported annual air emissions in 2022, EPA chose not to publish the individual biodiesel or renewable diesel facility emission factors due to the risk of disclosing CBI. However, the steps to calculate biodiesel production emissions factors were outlined in the technical memo and performed analogously to the ethanol production emission factors in the docketed spreadsheet.

To determine air emissions impacts, EPA used individual facility RINs generated in 2022 and the air emissions reported by those facilities in 2022. EPA did not determine processes within production facilities responsible for emissions or compare process emissions associated with the production of differing biofuel types such as biodiesel or renewable diesel. In determining the

[198] The methodology for determining pollutant emission rates from biofuel production is discussed in "Determination of Air Pollutant Emissions Factors from the Production of Biofuels," available in the docket for this action.

emissions impacts of air toxics from biodiesel production facilities, EPA used the annual emissions of air toxics from biodiesel facilities, as reported by the facilities. EPA did not compare air toxics emissions from the production of biodiesel or renewable diesel to petroleum refineries in this analysis.

EPA refined its methodology for estimating the criteria pollutant and air toxics emissions impacts from the production of renewable fuels in the DRIA for the proposed rule. We believe the emissions factors presented in the DRIA, and used in the final rule RIA as well, represent accurate estimates given the current available data and are an improvement on the methodology previously published in other RFS regulatory impact analyses.

As stated in the RIA Chapter 4.1.2.1.2, the lack of quantitative estimates of avoided emissions from biogas flaring is a limitation and source of uncertainty in this analysis. However, EPA believes the emissions estimates for the production of renewable CNG and LNG from biogas are the most accurate possible given the information currently available. The biogas CNG/LNG analysis only accounted for emissions from processes that wouldn't exist absent fuel production from biogas. For example, emissions associated with the transport of animal waste were not included, but emissions associated with the purification of biogas were.

9.2.3 Water Quality and Quantity

Comment:

Several commenters were focused on soil and water quality and quantity impacts from the production of biofuels compared to fossil fuels. With respect to water quantity, there was both concern for water needs as well as disputes on the claim that biofuel production is more water intensive.

A commenter stated that EPA correctly recognizes that conversion of grasslands or other lands to production of agriculture for biofuel feedstocks adversely affects soil quality, and leads to an increase in pesticide use which detrimentally affects nearby and downstream water quality. The commenter noted that EPA found that ethanol, biodiesel, and renewable diesel made from vegetable oils are substantially more water intensive than the petroleum fuels they would displace, and therefore there will likely be some increased irrigation pressure on water resources due to the proposed volumes.

However, another commenter disputed this claim, arguing that biodiesel production has been found to have minimal impacts on water quantity and availability, citing studies that showed overall oil refinery water consumption is 0.29–0.63 gallon water per gallon of refinery products, while estimated water consumption for biodiesel production is 0.31 gal/gal. The commenter also noted that EPA has previously recognized that more water is needed for renewable diesel plants than biodiesel plants. The commenter criticized EPA for only minimally recognizing that conservation practices can help mitigate any potential effects without providing much analysis of the positive environmental impact of maintaining existing farmland and preventing land development which increases stream bank erosion and sediment. The commenter noted that EPA acknowledges that soy crops may have reduced impacts on water quality than corn crops. The commenter stated that soybeans require less fertilizer, pesticide, and irrigation inputs than most commoditized row crops, and therefore represent significantly less potential water quality and quantity impacts.

Additionally, the commenter stated that EPA references the potential for spills but ignores that biodiesel is substantially less toxic than petroleum diesel, which it replaces, making biodiesel highly suitable for marine and farm uses and reducing its potential impact on soil and water. The commenter contrasted this with oil, which is often shipped over long distances with greater risk of leakage and spills.

Another commenter stated that where EPA's analysis focuses on the potential impacts of crop-based biofuels on soil and water quality associated with increased corn and soybean production, these statements in passing are unsupported and unexplained. In addition, the commenter said that EPA has previously acknowledged that petroleum used to produce gasoline and diesel fuel also impacts soil and water quality, but the DRIA does not include any such analysis to conduct a comparison here.

Response:

CAA section 211(o)(2)(B)(ii) requires EPA to analyze a number of environmental factors (*e.g.*, water quantity) in its determination of the appropriate volumes to establish under the set authority. In doing this analysis EPA is focused on the impacts from this rulemaking, and not in comparison to those from petroleum fuels that would be displaced. Nevertheless, EPA appreciates these comments related to this topic.

In analyzing the environmental factors in Chapter 4, EPA makes qualitative conclusions about potential effects from this rulemaking by leveraging findings from the 2025 Third Triennial Biofuels and the Environment: Report to Congress (RtC3) in addition to other studies, which are the best available information and most current science.

Regarding potential water and soil quality impacts associated with the renewable fuel volumes, we discuss this in RIA Chapter 4.3. To support and explain how production of crop-based feedstocks affects soil quality for example, we draw from a study from the RtC3 that used the Environmental Policy Integrated Climate (EPIC) model to quantify the increased erosion, nitrogen loss, and soil organic carbon loss due to the RFS program from 2008–2016. EPA notes that the true impacts are difficult to determine and depend on a variety of factors. For example, whether soybean or corn or another crop is cultivated is one factor, as soybeans require less fertilizer than other crops as one commenter acknowledged.

Comment:

A commenter expressed concern about their reservation, and stated that expanded agricultural production to meet biofuel targets—especially in areas upstream or adjacent to the San Luis Rey River watershed—could exacerbate water withdrawals, introduce increased pesticide and fertilizer runoff, and strain already limited groundwater supplies. The commenter said that these impacts may directly affect the availability and quality of water resources critical not only for their community's health, but for the protection of culturally significant plants and habitats. The commenter said that these impacts cannot be treated as secondary, and must be acknowledged, evaluated, and protected against through culturally informed environmental review processes.

Response:

EPA addresses potential water quantity, water quality, and wildlife effects in RIA Chapter 4. EPA draws from scientific studies and analyses to make qualitative conclusions about potential impacts from this rulemaking and acknowledges that understanding the true impacts at the local level remains a challenge due to a long causal chain relationship between the RFS standards and the land use effects that could result from increased production of crop-based feedstocks.

Comment:

A commenter argued that EPA's concerns about biogas systems are unsupported and unexplained. The commenter stated that the addition of RNG upgrading technology to an anaerobic digester helps financially incentivize better waste stream management, mitigate water quality impacts from waste, and reduce nutrient runoff. Additionally, the commenter noted that EPA previously found that there were no water requirements for consumption and withdrawals for biogas from landfills, wastewater, and animal manure digesters, and there were negligible water requirements for the processing and treatment of biogas. The commenter concluded that biogas collection and treatment do not have significant water requirements and, therefore, would not impact water quantity.

Response:

The use of manure management systems such as digesters can be a useful tool in nutrient management, if utilized properly. Water quality issues on animal farms often stem from runoff that is high in phosphorus and nitrogen due to manure. Digesters allow for the collection of manure and concentration of this nutrient-rich runoff into a single effluent stream, making it easily treatable. However, some farms may not utilize this secondary treatment technology. This decision-making is largely based on state and local regulations. More information on water quality can be found in RIA Chapter 4.3.

9.2.4 Ecosystems, Wildlife Habitat, and Conversion of Wetlands

Comment:

A commenter stated that increasing U.S. demand for biofuels from the RFS program is likely driving millions of acres of international cropland conversion, with associated climate, soil, and water harms, in violation of EISA requirements. The commenter also stated that EPA's analyses in the RtC3 estimated that the RFS program resulted in up to 1.9 million acres of domestic cropland expansion and up to 3.5 million acres of corn expansion between 2005 and 2016, with even greater potential land use changes likely estimated for soybean production relative to corn production. The commenter noted that these estimates did not account for direct or indirect international land use impacts.

Response:

Though we acknowledge that impacts outside the U.S. may occur, as we note in Chapter 4 of RIA, for statutory and program evaluation purposes we limit our scope to environmental impacts (*e.g.*, natural land conversion, water quality) within the U.S. For more information, EPA has evaluated international effects from biofuels and the RFS program in Chapter 16 of the RtC3. EPA has also modeled international effects as part of the climate change analysis discussed in RIA Chapter 5.

Comment:

Another commenter noted that the RTC3 conclusion that there may be zero acres of land use conversion attributable to corn ethanol becomes lost in EPA's discussions of environmental impacts. The commenter stated that the RTC3 includes several flawed and conservative assumptions, and that it is inappropriate for EPA to rely upon the discredited work of Lark et al. The commenter also criticized EPA for citing studies that were never intended to evaluate the impacts of renewable fuels. The commenter urged EPA to clarify the relevance of cited studies and provide appropriate context.

Response:

In RIA Chapter 4.2, EPA summarizes findings from the RtC3 that include zero in the range, for example: "…the RtC3 completed an attribution analysis for corn ethanol and estimated that 0–9% of corn ethanol production and consumption is likely attributable to the RFS program historically from 2006–2019" and "…the report recognized that only a percentage of [wetlands converted in the Prairie Pothole Region from 2008-2016] (0–20%) may be attributable to the RFS program." EPA believes that the analyses in the RtC3 used the best currently available science and information to evaluate the historical effects of the RFS program on land use conversion, and that this information can help us understand potential future effects assuming that land use change patterns mirror past trends.

To further assess how land conversion to agriculture could affect environmental end points such as water quality, EPA completed a review of more recent literature. EPA cited studies examining the effects from agricultural conversion broadly in addition to studies that examined effects from increased demand for renewable fuel production specifically. EPA believes including such studies is helpful in qualitatively drawing conclusions regarding the potential impacts from this rulemaking due to the long causal chain connecting the RFS standards to potential land use change impacts. With regard to work of Lark et al., EPA cited the same studies that were included in the RtC3 as well as some of their more recent work[199]. EPA clarified in the final RIA how the coefficients used in Lark et al. (2022) differed from the coefficients used in EPA's RtC3 as well as the Set 1 Rule Biological Evaluation, leading to different results. In summary, in the RtC3, EPA estimates a smaller effect from the RFS based on an additional attribution analysis that separated the effects of the RFS program from the impacts of biofuels generally.

Comment:

A couple of commenters further discussed that EPA's analysis of the impacts of the 2026-2027 proposed volumes indicate a potential increase in land conversion to produce more feedstock to meet extra BBD volume demands, which could contribute to loss of natural lands. One commenter stated that EPA does not offer estimates of the amount of land conversion and attempts to downplay the associated harms, in part by focusing the DRIA discussion of land conversion largely on U.S.-based studies and data. The commenter requested that EPA account for global emissions stemming from expanding cropland in the U.S. or abroad and consider the potential harms from international land conversion in setting volumes.

Response:

Though we acknowledge that impacts outside the U.S. may occur, as we note in Chapter 4 of RIA, for statutory and program evaluation purposes we limit our scope to environmental impacts (*e.g.*, natural land conversion and associated effects) within the U.S. For more information, EPA has evaluated international effects from biofuels and the RFS program in Chapter 16 of the RtC3. EPA has also modeled international effects as part of the climate change analysis discussed in RIA Chapter 5.

Comment:

A commenter discussed that for crops to count towards the renewable fuels volume mandate, the land must meet three criteria: (1) cleared or cultivated prior to 2007, (2) actively managed or fallow in 2007, and (3) non-forested in 2007. These requirements prevent land not cultivated before 2007 from being used to increase biofuel production, thereby reducing GHG emissions from initial soil cultivation while avoiding negative environmental impacts associated with land conversion.

The commenter argued that EPA's enforcement strategies for these restrictions have achieved questionable past success, citing EPA's estimates that the RFS program's effects on corn ethanol

[199] Lark, Tyler J., Nathan P. Hendricks, Aaron Smith, Nicholas Pates, Seth A. Spawn-Lee, Matthew Bougie, Eric G. Booth, Christopher J. Kucharik, and Holly K. Gibbs. "Environmental outcomes of the US Renewable Fuel Standard." *Proceedings of the National Academy of Sciences* 119, no. 9 (February 14, 2022). https://doi.org/10.1073/pnas.2101084119.

could have driven up to 1.9 million acres of domestic cropland expansion and up to 1.6 million acres of international cropland expansion. The commenter noted that while not quantified, EPA finds that the RFS program's effects on soy biodiesel global land conversion are uncertain but potentially significant. The commenter suggested that with 50 million acres of U.S. cropland already dedicated to biofuel production, these estimates of past land conversion are likely underestimates, and meeting the restrictions for the proposed volumes is highly doubtful given EPA's own climate modeling predicts conversion of millions of acres globally.

Response:

EPA established the aggregate compliance provision in the 2010 final rule[200]. Codified in 40 CFR 80.1454(g), this provision ensures that the total amount of agricultural land does not exceed that which existed in 2007. Insofar as additional crop-based feedstocks may be used to produce biofuel in the 2026–2027 timeframe, the aggregate compliance provision ensures that it cannot result in a net increase in the conversion of non-cropland to cropland.

Further, though we acknowledge that impacts outside the U.S. may occur, for statutory and program evaluation purposes we limit our scope in RIA Chapter 4 to environmental impacts (*e.g.*, natural land conversion and associated effects) within the U.S. For more information, EPA has evaluated international effects from biofuels and the RFS program in Chapter 16 of the RtC3. EPA has also modeled international effects as part of the climate change analysis discussed in RIA Chapter 5.

Comment:

In contrast, a commenter argued that any connection between setting annual consumption standards for renewable fuel and purported environmental impacts from crop production is "most likely de minimis or non-existent." The commenter discussed that the proposed standards maintain the same implied conventional volume of 15 billion gallons first prescribed in 2015, but that at the current annual U.S. production and export rates, not a single additional gallon of ethanol would need to be produced to comply with the 2026 and 2027 standards.

The commenter further argued that even if the proposal did incentivize an increase in corn production, this would not likely result in cropland expansion into natural lands. The commenter cited experts who explained that "the least costly option [to increase crop production] is to increase yields on previously farmed lands." The commenter noted that U.S. corn planting acres have been stable for decades as increases in demand have consistently been met with increases in yield, and agricultural land area even decreased by 38 million acres when annual ethanol production increased by 13.8 billion gallons from 2002-2017.

Relatedly, a commenter stated that agricultural land under production has been declining since 2007, and in the meantime that use of conservation practices is increasing. The commenter criticized EPA for continuing to reference disputed studies by Lark et al. that attribute conversion of grassland to cropland to the RFS program. The commenter discussed that the impacts identified on wetlands, ecosystems, and wildlife habitat from land use change by EPA are largely

[200] 75 FR 14701 (March 26, 2010)

based on crop production. However, the commenter argued that EPA's reference to analysis from 2024 regarding the impact of the RFS program on biodiesel production seems irrelevant, given that the commenter requested a biodiesel-specific target less than what industry achieved in prior years and that EPA projects no increases in biodiesel through 2030. The commenter expressed the belief that supporting biodiesel through the RFS program will not result in any impacts on wetlands, ecosystems, and wildlife habitat from any land use changes, and instead the program would incentivize new entrants into the renewable diesel market to look for new or alternative feedstocks.

Response:

In RIA Chapter 4.2, EPA summarizes findings from the RtC3 that indicate the RFS program contributed to no ethanol-driven land use change in certain years in the past. For example: "…the RtC3 completed an attribution analysis for corn ethanol and estimated that 0–9% of corn ethanol production and consumption is likely attributable to the RFS program historically from 2006–2019." EPA believes that the analyses in the RtC3 used the best currently available science and information to evaluate the historical effects of the RFS program on land use change. With regard to the work of Lark et al., EPA clarified in the final RIA how the coefficients used in Lark et al. (2022)[201] differed from the coefficients used in EPA's RtC3 as well as the Set 1 Rule Biological Evaluation, leading to different results. In summary, EPA estimates a smaller effect from the RFS based on an additional attribution analysis that separated the effects of the RFS program from the impacts of biofuels generally.

To make qualitative conclusions about the potential Set 2 Rule impacts on environmental end points, EPA relies on the volume changes expected from this rule relative to the No RFS and 2025 Baselines. With regard to conventional renewable fuel volumes, the analyses suggest increases in conventional volumes from this rule, which could lead to further land use conversion to agriculture.

However, as noted in the RIA, it is challenging to understand the true impacts of the RFS program and the Set 2 Rule due to a long causal chain relationship between the RFS standards and the land use effects that could result from increased production of crop-based feedstocks. There is high uncertainty inherent in every step in the underlying causal relationship. This includes, for example, unpredictable shifts in imports and export dynamics which complicate our understanding of actual land conversion effects from this rule.

Comment:

A commenter discussed that through the EISA, Congress established program goals to develop less resource- and land-intensive feedstocks and to require systematic evaluation of environmental impacts of expanded biofuel production. However, the commenter argued that EPA's own analyses establish that the RFS program has not advanced the environmental benefits

[201] Lark, Tyler J., Nathan P. Hendricks, Aaron Smith, Nicholas Pates, Seth A. Spawn-Lee, Matthew Bougie, Eric G. Booth, Christopher J. Kucharik, and Holly K. Gibbs. "Environmental outcomes of the US Renewable Fuel Standard." *Proceedings of the National Academy of Sciences* 119, no. 9 (February 14, 2022). https://doi.org/10.1073/pnas.2101084119.

Congress intended. The commenter noted that the RFS program overwhelmingly is based on the production of crop-based biofuels, which has previously caused extensive land conversion both domestically and abroad and has led to detrimental climate and environmental impacts. In addition, the commenter stated that the RTC3 identified adverse effects on ecosystems and wildlife habitat, which the commenter argues supports lower volumes for BBD and conventional renewable fuel. In particular, the commenter expressed concern that the production of crop-based biofuels can cause pesticide drift or agricultural runoff which can affect ecosystems and species.

Another commenter said that the RFS program remains the single largest Federal agency action impacting land use and land conversion decisions across the U.S. and it continues to increase nutrient pollution, pesticide pollution, and substantial habitat loss for the nation's threatened and endangered species. The commenter said that EPA should use RINs to properly incentivize the sustainable production of feedstocks to ensure that harmful pollution is minimized. The commenter said that EPA can and should develop a "no net loss" policy for biofuels and land conversion similar to EPA and Army Corps approach to wetland conservation under the Clean Water Act.

Response:

CAA section 211(o)(2)(B)(ii) requires EPA to analyze a number of environmental factors in its determination of the appropriate volumes to establish under the set authority, including factors on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply. RIA Chapter 4 analyzes the rulemaking's potential effects on many of these environmental factors (climate change is assessed in Chapter 5). The discussions leverage the findings from the RtC3, finalized in January 2025, which provides additional information on environmental impacts from biofuels and the RFS program.

EPA makes qualitative conclusions about potential effects from this rulemaking based on the best currently available science and information on the effects of the RFS program and renewable fuels production in general. EPA acknowledges the long causal chain relationship between the RFS standards and the environmental effects that could result from increased production of crop-based feedstocks.

Comment:

Another commenter stated that the expansion of renewable fuel infrastructure poses risk to historic properties and cultural resources on reservation land. The commenter said that no action that may disturb or degrade these spaces should move forward without thorough identification, assessment, and mitigation in partnership with Tribal governments.

Response:

To the extent that the federal government is involved in the expansion of renewable fuel infrastructure, the identification, assessment, and mitigation of risk shall be undertaken in partnership with impacted Tribal governments during the permitting process.

Comment:

Commenters said that when soy oil is shifted from non-energy sectors to energy sectors, palm oil is the marginal product on the global market that fills the gap. The commenters said that the expansion of soybean and palm oil is a major driver of tropical deforestation, and are the largest drivers of deforestation after cattle. One of the commenters said that EPA's new volume requirements will create high demand for new production of other feedstocks to backfill qualifying feedstocks, which will in turn cause new lands to be cleared, in direct violation of the CAA. A commenter argued that EPA failed to analyze the environmental impacts of feedstock shifts on other non-fuel markets as required by the statute. The commenter argued that EPA must assess the environmental impacts of increasing the use of other vegetable oils to replace SBO.

Response:

CAA section 211(o)(2)(B)(ii) requires EPA to analyze a number of environmental factors in its determination of the appropriate volumes to establish under the set authority, including factors on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply. RIA Chapter 4 analyzes the rulemaking's potential effects on many of these environmental factors. Regarding the conversion of lands, including conversion of wetlands and ecosystems, EPA focused on the potential effects from the domestic growth of crop-based feedstocks. Though we acknowledge that impacts outside the U.S. may occur, as we note in the RIA, for statutory and program evaluation purposes we limit our scope to impacts within the U.S.

For more information, EPA has evaluated international effects from biofuels and the RFS program in Chapter 16 of the RtC3. EPA has also modeled international effects as part of the climate change analysis discussed in RIA Chapter 5. For this analysis, EPA used three global economic models to evaluate the impacts of the increased volumes of crop-based biofuels (such as soybean oil BBD). This analysis included estimates of the impact of the rule on global vegetable oil markets, including for non-fuel purposes.

Comment:

In contrast, a commenter stated that the proposed rule properly recognizes that cellulosic biofuels are not anticipated to cause substantial land use changes or significant adverse environmental impacts. The commenter added that while some RNG projects may require minimal additional infrastructure, no impacts on wetlands, ecosystems or wildlife habitat are expected. Another commenter said that any concerns with the propagation of palm oil trees is irrelevant to Canadian-sourced RNG, and randomly lumping clean RNG with these suspect and unlawful feedstocks is arbitrary and capricious. A commenter said that corrected, updated analyses relying on improved methods, consistent land classification systems, and the accumulation of copious verifiable historic data, combined with life-cycle assessments from diverse sources, have repeatedly confirmed that low-carbon biofuels reduce GHG emissions and environmental impacts because the farmland used to produce biofuel crops was previously in agricultural production and not converted from untilled prairie grasslands or forests. Additionally, the commenter said that there are fewer acres in principle crop production since the RFS program was established, not more. Other commenters stated that historical trends show that U.S. SBO and corn use for biofuels has been met through improved yields, expanded domestic processing, and reduced exports, rather than through cropland expansion or conversion of natural lands. The commenters said that EPA's recognition of these dynamics is important.

Response:

EPA appreciates this comment related to RNG projects, however for our analyses EPA focused on the potential effects from crop-based feedstocks including those from corn, soy, and canola, as they are the primary concern when it comes to potential land conversion effects. EPA notes in its analyses that the true effects from the rulemaking will depend on a variety of factors, including domestic processing capacities and shifting import and export dynamics.

Comment:

A commenter stated that EPA's analysis of the proposal's impact on wetlands, ecosystems, wildlife habitat, water quality, water supply, and soils suffers from fundamental and overlapping flaws. The commenter, along with another, argued that EPA relies upon studies that fail to establish any causal connection to the proposal, the RFS program, or renewable fuel production in general.

Response:

RIA Chapter 4 analyzes the rulemaking's potential effects on these environmental end points including wetlands, ecosystems, wildlife habitat, water quality, soil quality, and water quantity. EPA makes qualitative conclusions about potential effects from this rulemaking based on the best currently available science and information on the effects of the RFS program and renewable fuels production in general. EPA acknowledges the long causal chain relationship between the RFS standards and the environmental effects that could result from increased production of crop-based feedstocks.

9.2.5 Endangered Species Act

Comment:

A commenter suggested that EPA should have developed a program under ESA section 7(a)(1) to conserve species and habitats.

Response:

EPA is engaged in consultation for this action under ESA section 7(a)(2). Because ESA section 7(a)(1) addresses broader programmatic issues related to how federal agencies and the Services are to use their authorities to carry out programs for the conservation of endangered species and threatened species listed pursuant to ESA section 4, this comment is outside the scope of this action.

Comment:

Several commenters supported EPA's "not likely to adversely affect" Endangered Species Act (ESA) determination from the Set I Rule and recommended the same determination for Set II. The commenters noted that the D.C. Circuit upheld this determination against challenges by environmental groups, concluding it was "reasonable and reasonably explained."

One of the commenters described the lengthy causal chain that would need to occur for the RFS program to impact endangered species: (1) RFS volumes would need to drive increased biofuel demand; (2) producers would need to purchase more feedstock rather than divert existing biofuel surplus; (3) this would need to cause a sufficient spike in crop prices to spur farmers to produce more crops; (4) farmers would need to plant new acres instead of intensifying yields or diverting crop exports; (5) farmers would need to plant those new acres on uncultivated land; and (6) those new acres would need to be located where species could be impacted. The commenter argued that recent developments have rendered it less likely that species will be impacted. The commenter noted that increased volumes can be met without any need for additional planting of soy, much less planting of soy on uncultivated land in areas where endangered species live.

Another commenter similarly argued that any connection between setting annual consumption standards for renewable fuel and purported environmental impacts from crop production is extremely attenuated at best, and most likely de minimis or non-existent. Another commenter said that there is no evidence linking the RFS program to the conversion of grasslands, and loss of, or adverse effect to, ESA-linked species.

Response:

EPA is engaged in consultation for this action under ESA section 7(a)(2). Our ESA analysis is provided in the Biological Evaluation, available in the docket for this action.

Comment:

A commenter noted that EPA plans to complete its Biological Evaluation for Set 2 using the same analytical approaches used in Set 1’s Biological Evaluation; however, EPA itself admits that Set 1’s Biological Evaluation overestimated cropland increases from the Rule. The commenter said that employing the same analytical approach to determine natural land conversions for Set 2 will continue to overestimate the dependent environmental impacts of the RFS program from natural land conversion as market dynamics heavily mitigate land use change.

Another commenter similarly criticized EPA’s analysis of the proposal’s impact on wetlands, ecosystems, wildlife habitat, water quality, water supply, and soils, arguing it suffers from fundamental and overlapping flaws. They stated that across each of these analyses, EPA relies upon studies that fail to establish—and in most cases do not even attempt to establish—any causal connection to the proposal, the RFS program, or even renewable fuel production in general. They argued that EPA instead recites various environmental impacts purportedly resulting from agricultural activity generally, rather than analyzing the likely “impact of the production and use of renewable fuels” on the listed environmental factors as required by statute.

The commenters recommended that EPA should reconsider its analytical approach and revise its approach to its Biological Evaluation, including capturing the net cropland acre impacts that take crop-switching into account and feedstock imports and exports that prevent natural land conversion to cropland. They also suggested that EPA should avail itself of the latest Annual National Land Cover Database data from the U.S. Geological Survey to inform its Evaluation. One of the commenters recommended that EPA should instead consider analyses by Austin et al. 2022 and Taheripour et al. 2022, which they claimed provide a more reasonable, yet still very conservative, starting point. The commenter also recommended that EPA and the Services utilize screening tools to focus on areas and species most relevant to agricultural expansion. They suggested using county-level data from the Cropland Data Layer to evaluate recent land use trends, categorizing land cover into at least five broad categories: 1) corn/soy/canola; 2) other crops; 3) grassland/pasture; 4) forest/shrubland/wetland; and 5) non-crop. They proposed comparing Cropland Data Layer maps between years to identify how frequently transitions between land categories occur, and excluding counties where the conversion of natural lands into cropland is shown to be very uncommon from EPA’s action areas. They further suggested comparing a species’ total range to the portion of that range overlapping with natural lands within the remaining counties not excluded by the first screening step. By comparing the area of overlap with the likelihood of land conversion based on historical trends, the agencies could approximate a probability of impact on the species and exclude species where this probability is below a certain threshold. After screening out species where impacts are extremely unlikely, EPA and the Services would have a more manageable list of remaining species for which to conduct species-specific analysis. Similarly, a commenter said that while EPA may not be able to specifically predict exactly which particular areas of corn of soy or other crop might be grown on, this fact does not obviate EPA’s duty to make a landscape level assessment of the overall, aggregate impact of its decisions as they apply to listed species.

Response:

EPA is engaged in consultation for this action under ESA section 7(a)(2). Our ESA analysis is provided in the Biological Evaluation the docket for this action.

Comment:

A commenter applauded the attention that EPA, National Marine Fisheries Service, and Fish and Wildlife Service are paying to compliance with ESA Section 7 but argued that the deficiencies identified by the D.C. Circuit Court in *Center for Biological Diversity v. EPA*, such as potential tensions within the ESA Section 7 regulations, and between the Section 7 regulations and the National Marine Fisheries Service and Fish and Wildlife Service Section 7 Handbook, likely require further explanation from all three agencies—and a greater level of coordination—in order to produce a unified, consistent approach to Section 7 compliance. The commenter recommended that all three agencies should take a combined approach: explain why the facts support a "no effects" determination under a proper reading of the regulations and Handbook, but go on to conduct a "not likely to adversely affect" analysis and make a "not likely to adversely affect" finding. The commenter said that this combined, comprehensive approach is the most conservative strategy for bolstering the defensibility of the rule while preserving all legal arguments moving forward.

Response:

EPA is engaged in consultation for this action under ESA section 7(a)(2). Our ESA analysis is provided in the Biological Evaluation the docket for this action.

Comment:

A commenter expressed opposition to EPA's approach in the Set I rule to create an action area based on the entire area "where corn, soybean, and canola are currently grown and could be grown", which covered about two-thirds of the continental United States. The commenter stated that EPA expressly disavowed that its estimates represented acreage of crop expansion that was "reasonably certain" to occur, and instead described its process as a "hypothetical," "worst-case" exercise. The commenter argued that EPA's probabilistic analysis was not a tool designed to address the threshold question of whether potential environmental effects are capable of meeting the regulatory definition of "effects of the action."

Response:

EPA is engaged in consultation for this action under ESA section 7(a)(2). Our ESA analysis is provided in the Biological Evaluation the docket for this action.

9.3 Comparison of Costs and Benefits

Comment:

A number of commenters stated that the proposed standards are too high because the costs estimates in the analysis of the proposed standards out-weigh the benefits estimates. Some commenters stated that EPA's analysis of the statutory factors overstates societal benefits, while other commenters stated that additional benefits were not represented in EPA's analysis of the statutory factors, or that EPA's analysis otherwise underestimated benefits. One commenter argued that standards should be based on what volumes are achievable rather than minimizing program costs.

Response:

EPA evaluated a range of factors, as required by statute, when determining the appropriate volume standards set in this rulemaking, including but not limited to environmental and economic factors for which impacts were monetized. We note that the statute does not require EPA to weigh these factors in isolation, but rather to weigh all the statutory factors, nor does the statute indicate how to weigh the factors. The D.C. Circuit has concluded that Congress gave EPA "considerable discretion to weigh and balance the various factors" in determining volumes under CAA section 211(o)(2)(B)(ii).[202]As discussed in Preamble Section II.B and Section III.D, EPA considered all of the assessed impacts and found the final volumes to be appropriate.

We note that the D.C. Circuit has acknowledged 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."[203]

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[202] *CBD* at 171, citing *Sinclair Wyoming*, 101 F.4th 887.
[203] Id.

10. Removal of Renewable Electricity from the RFS Program

10.1 Statutory Basis for Removal of eRINs

Comment:

A commenter suggested that CAA section 211(o)(5) prohibits RIN generation for eRINs. The commenter noted that CAA section 211(o)(5) enumerates specific circumstances under which credits can be generated. The commenter suggested that because there is no explicit or implicit discussion of credits for renewable electricity within CAA section 211(o)(5), the RFS program cannot allow RIN generation for renewable electricity.

Response:

While EPA agrees that the CAA prohibits RIN generation for renewable electricity for the reasons set forth in Preamble Section VII and within this document, we do not adopt the commenter's reasoning as a basis for our removal of renewable electricity from the RFS program. EPA has stated in the past that while CAA section 211(o)(5) sets the floor for what must be included in a credit program under CAA section 211(o), other provisions within CAA section 211(o) such as CAA section 211(o)(2)(A) provide additional authority for EPA to set up a compliance scheme that allows for the generation of credits. The "RIN" system, while fulfilling and implementing EPA's statutory obligations under CAA section 211(o)(5), also establishes a general compliance mechanism, established under CAA section 211(o)(2)(A) and section 301 that extends beyond the specific elements required in CAA section 211(o)(5).

The commenter's suggestion that credit generation is only permissible for the elements identified in CAA section 211(o)(5) and that credit generation for any other renewable fuel is prohibited is contrary to how EPA has implemented the program. For example, a foundation of the credit generation program is the provision for renewable fuel producers to generate credits; renewable fuel producers are not specifically enumerated in CAA section 211(o)(5). The current RIN system was established in the 2010 RFS2 Rule and has been consistently implemented since that time.

Comment:

A number of commenters were critical of EPA's use of the following definition of "fuel" to propose that renewable electricity was not a fuel under the CAA: "a material used to produce heat or power by burning.'' The commenters suggested that the use of this definition is inappropriate, particularly in light of the differing purposes between the RFS program and EPA's Risk Management Program (the origin of this definition of "fuel"). Some commenters suggested that such a definition is too narrow and would exclude other potential renewable fuels such as hydrogen.

Some commenters suggested that a more appropriate definition would be the one in the Energy Policy Act of 1992, which defined "replacement fuel" to include electricity, among other fuel types such as methanol, ethanol, and natural gas. Commenters also suggested that the

Automotive Propulsion Research and Development Act of 1978's definition of fuel as "any energy source capable of propelling an automobile" is more appropriate.

A commenter suggested that even under the definition provided at proposal, renewable electricity could still qualify as a fuel given the following definition of burn to mean "to consume fuel and give off heat, light, and gases."

A commenter also highlighted the use of the term "fuel" to include electricity within EISA. A comment noted that EPA itself has referred to electricity as a fuel within the RFS program, including in the 2010 and 2014 rulemakings. A commenter also highlighted the description of electricity as a fuel in the context of transportation on DOE's Alternative Fuels Data Center website. The commenter also highlighted the recognition of electricity as a fuel by Edison Electric Institute. The commenter pointed to the fuel economy ratings required under the Energy Policy and Conservation Act of 1975, and issued by EPA and the Department of Transportation (DOT), and noted that these ratings described electricity as a fuel.

Response:

In the Set 2 proposal, EPA put forward an argument that renewable electricity was not a "fuel" under common definitions such as "a material used to produce heat or power by burning." EPA recognizes that this definition is one used under EPA's Risk Management Program and is similar to dictionary definitions. Nevertheless, in this final rule, we take no position on whether electricity is a "fuel" and this argument is not a basis for our determination that renewable electricity is not a "renewable fuel" as defined by CAA section 211(o)(1)(J) within the RFS program.[204] We find that renewable electricity is not a renewable fuel under the RFS program for the reasons described in Preamble Section VII.

Comment:

A commenter suggested that the requirement to submit a report to Congress under Section 206 of EISA on renewable electricity is an indication that Congress did not permit renewable electricity under the RFS program. The commenter indicated that the phrase "adjunct to a renewable fuels mandate" is further indication that the inclusion of renewable electricity in the RFS program was not authorized.

Another commenter read Section 206 of EISA differently, suggesting that the Congressional direction to conduct a study as to the "feasibility" of issuing credits for renewable electricity was an indication that renewable electricity was intended to be a renewable fuel. The commenter reasoned that such a study would be unnecessary if renewable electricity was not a renewable fuel.

Finally, a commenter noted that EPA's action in the RFS2 final rule in 2010 to permit renewable electricity to generate RINs under the RFS program "more quickly satisf[ied] Congress's desire

[204] We also take no position on the definition of "fuel" as used in the RFS program more generally, and find that doing so is appropriate because the statute provides specific definitions for terms such as "renewable fuel" and "transportation fuel."

to ‘move the United States toward greater energy independence and security [and] increase the production of clean renewable fuels.’”

Response:

At proposal, EPA did not utilize section 206 of EISA as a basis for removing renewable electricity from the RFS program. We take no position in this action on the meaning of section 206 of EISA and again do not utilize the language in section 206 to justify our action to remove renewable electricity from the RFS program. We find that renewable electricity is not a renewable fuel under the RFS program for the reasons described in Preamble Section VII.

Comment:

A commenter suggested that EPA’s interpretation is “supported by the major questions doctrine,” because “including any form of electricity in a renewable fuel program would constitute a major question of political and economic significance for which Congress must provide a clear statement.”

Response:

The commenter did not provide sufficient explanation as to why including electricity in the RFS program would be a major question for EPA to meaningfully engage with this comment. We are aware of comments on the December 2021 Set 1 proposal that suggested that the eRINs program proposed there would implicate the major questions doctrine. Given that in this action we are withdrawing that proposal and finding that there is no statutory basis for including electricity in the RFS program for other reasons, we need not engage with those comments.

Comment:

Commenters highlighted seven occasions since 2019 where Congressional appropriators have spoken to eRINs. In particular, a commenter highlighted an appropriations bill explanatory statement that encouraged EPA to process pending eRIN registration requests within 90 days,[205] and a separate $500,000 appropriation “to address the backlog of eRIN registration applications.”[206] The commenters also cited additional appropriations language.[207] The commenters suggested these Congressional directives are “clear statements regarding” or “endorsements of” EPA’s authority to administer the eRIN program. A commenter also highlighted a recent bill “prohibit[ing] EPA from allowing eRINs;” the commenter suggested such a bill would not be necessary if the statute clearly did not include electricity.

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[205] S. Rept. 116-123 —Accompanies S.2580 Department of The Interior, Environment, And Related Agencies Appropriations Bill, 2020 (demanding EPA Take action on existing applications within 90 days of enactment).
[206] Explanation of the Consolidated Appropriations Act, Congressional Record 166:218 (December 21, 2020) p. H8539 (directing action on existing applications within 90 days of enactment).
[207] H. Rept. 117-83 Dept. of the Interior, Environment, and Related Agencies Appropriations Bill, 2022. 117th Cong. House Committee on Appropriations (July 2021) (action within 10 days for applications pending for more than 12 months). See also Explanation of the Consolidated Appropriations Act, Congressional Record 166:218 (Dec. 21, 2020) at H8539.

Response:

While commenters are correct that congressional appropriations language has in the past seemed to implicitly sanction an eRINs program within the RFS program, we note that such language does not have the same force of law as a statute that is enacted by the whole of Congress. Additionally, these statements are being made after the enactment of EISA in 2007 and thus have less persuasive weight about the meaning of the statute.

The instructions to EPA in the various congressional reports do not represent “congressional intent” regarding the eRINs provisions and do not obligate EPA to act in any particular way, given such language does not modify the statutory provisions of CAA section 211(o).

We note as well that it is possible the bill language prohibiting eRINs could be in response to EPA’s prior actions regarding eRINs, including the Set 1 proposal, and other regulatory actions to facilitate the participation of eRINs in the RFS program. As noted above, later proposed legislation is less persuasive about the meaning of the legislation when enacted. The bill language is not dispositive as to whether eRINs are a renewable fuel under CAA section 211(o)(1)(J).

Comment:

Multiple commenters supported EPA’s proposed interpretation that CAA section 211(o)(1)(J)’s definition of “renewable fuel” excludes electricity because it is limited to biofuels that physically displace a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine. One commenter supported EPA’s application of *Loper Bright Enterprises v. Raimondo* to interpret the statute as laid out in the proposal, and the corresponding change to remove electricity from the RFS program. Another commenter stated that there is no support in the statute for including electricity generation in the RFS program and such inclusion is in conflict with the plain language of the statute. This commenter pointed to the statutory definitions of transportation fuel, renewable fuel, and additional renewable fuel and asserted that electricity is not a fuel or renewable fuel under these definitions.

Another commenter noted that renewable electricity does not displace liquid fossil fuels in the transportation sector in the same direct and quantifiable manner as liquid or gaseous renewable fuels.

One commenter noted that the definition of “additional renewable fuel” in CAA section 211(o)(1)(A) reinforces that renewable electricity is not a renewable fuel. The commenter stated that “additional renewable fuel” means “fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in home heating oil or jet fuel,” emphasizing that this definition again provides that renewable fuel must “replace or reduce the quantity of fossil fuel *present in* home heating oil or jet fuel” (emphasis added). While electricity can substitute for heating oil, it cannot reduce the fossil fuel *present in* home heating oil or jet fuel because electricity is not fungible with fuels.

Multiple commenters stated that the RFS program is a liquid biofuel program. One commenter stated that including eRINs in the RFS program dilutes the value of RINs generated from tangible, combustion-based renewable fuels—such as RNG—that are used directly in vehicles and infrastructure designed for petroleum fuels. This commenter further stated that using RNG for vehicle fuel applications allows for the direct displacement of diesel and gasoline.

Commenters also engaged with the definition of "transportation fuel" in CAA section 211(o)(1)(L). One commenter stated that this definition reinforces that transportation fuels must be within the meaning of a fuel and that, since electricity is not a fuel, it cannot be a transportation fuel that qualifies for the RFS program.

Response:

EPA acknowledges these comments. As noted elsewhere in this section, the Agency is taking no position in this final rule on whether electricity is a "fuel." EPA is not basing the determination that renewable electricity is not a "renewable fuel" under CAA section 211(o)(1)(J) on whether or not electricity is a "fuel" for purposes of the RFS program.

EPA reinforces that its rationale for removing renewable electricity from the RFS program does not preclude gaseous fuels such as renewable CNG/LNG from qualifying as renewable fuel. As explained in Preamble Section VII, EPA believes the statute's references to "volumes" and "gallons" indicates that Congress intended the RFS program to include fuels that could be measured in physical quantities. Renewable CNG/LNG is quantified in terms of physical volume (see, *e.g.*, 40 CFR 80.155(a)) and replaces fossil natural gas that is present in a motor vehicle or motor vehicle engine and thus qualifies as renewable fuel. EPA does not take the position that renewable fuels are limited to *liquid* biofuels, but rather to fuels that have physical volumes that can, in turn, physically displace fossil fuels.

Relatedly, the displacement that is relevant for purposes of CAA section 211(o)(1)(J) is displacement of fossil fuel that is present in a transportation fuel—not necessarily displacement of fossil-based gasoline or diesel. While such gasoline and diesel represent the baseline for purposes of determining lifecycle GHG emissions under CAA section 211(o)(1)(C) and (H), the definition of renewable fuel provides that a renewable fuel must "replace or reduce the quantity of *fossil fuel* present in a transportation fuel."[208] That is, the displacement that is relevant for purposes of determining lifecycle GHG emissions and emission reductions under CAA section 211(o)(1)(C) (fossil-based *gasoline or diesel*) is distinct from the displacement required under section 211(o)(1)(J) (fossil fuel). The former is an assumption for purposes of performing a calculation, while the latter is a definitional requirement.

Comment:

Multiple commenters disagreed with EPA's proposed interpretation of CAA section 211(o)(1)(J) and with its proposed determination that the statute does not give EPA the authority to include electricity in the RFS program. Commenters pointed out that it has been EPA's interpretation since the 2010 RFS2 rule that electricity can be a renewable fuel under the RFS program, and

[208] CAA section 211(o)(1)(J) (emphasis added).

that there were no concerns raised at that time regarding the eligibility of electricity under the statute. Multiple commenters stated that EPA is now proposing a novel interpretation of the statute but provides no rationale for revisiting the statutory analysis after 15 years with respect to renewable electricity. One commenter stated that delays due to concerns over how to implement a part of the program is not a reason to revise a long-standing reading of the statute, particularly where it might have broader implications that may not have been considered.

Multiple commenters stated that the statute is not limited to liquid fuels, or to liquid and gaseous fuels. One commenter noted that while EPA stated that there are "over fifty references to liquid fuels," the term "liquid fuel" is not used. Instead, CAA section 211(o)(1)(B)(ii)(V) provides that "biogas" is an advanced biofuel. However, commenter noted, biogas cannot be used directly in vehicles. As such, Congress's use of the term is more appropriately read as relating to any biogas-derived fuel that is from renewable biomass and meets the 50% or 60% lifecycle greenhouse gas emissions reduction to be advanced biofuel or cellulosic biofuel, which includes renewable electricity. The commenter argued that because biogas is produced from the decomposition of organic wastes, it stands to reason that Congress would have considered it a source of advanced biofuels. Had Congress only wanted CNG/LNG to be included, it could have easily said so. EPA does not treat natural gas as an obligated fuel and, as such, the fossil fuel being replaced is the gasoline or diesel fuel that otherwise would be used in lieu of renewable electricity in an electric vehicle or CNG/LNG in a natural gas vehicle. Further, biogas displaces fossil fuel use in the electricity grid. As such, it fully complies with the purposes and express language of the Clean Air Act. The commenter stated that there is no reasoned justification to find that, while Congress sought to support biogas, it did not intend to include biogas used to generate electricity that is used as transportation fuel.

Multiple commenters stated that EPA's reference to the statute's use of "volume" and "gallons" does not indicate that renewable electricity is not eligible. One commenter asserted that Congress provided authority to generate an "appropriate" amount of credits under CAA section 211(o)(5)(A). EPA has long had regulations that convert both biogas and renewable electricity to "volumes" in "gallons." Where the renewable fuel is displacing fossil-based gasoline and diesel fuel, it makes sense that EPA used the terms volume and gallon. Where units are easily converted, this does not evidence that Congress only sought to limit the types of renewable fuels allowed under the program, so long as those fuels are produced from renewable biomass and meet the required greenhouse gas emission reductions.

A commenter stated that when Congress expanded the scope of the RFS is 2007, it adopted an expansive definition of "renewable fuel" that includes *any* fuel for use in *any* type of motor vehicle. This clearly includes fuel used in an electric vehicle, so long as it is (a) "produced from renewable biomass" and (b) "used to replace or reduce the quantity of fossil fuel present in a transportation fuel." The commenter argued that, moving beyond the narrower version of the RFS program first created by EPAct in 2005, the definition was no longer tied to a "fuel mixture" but instead referred more broadly to "transportation fuel." Nothing in the definition limited renewable fuels to liquid fuels or gaseous fuels measured in "gallons" or "volumes."

The commenter noted that EPA's suggestion that because there is no mention of electricity and over fifty references to liquid fuels would also disqualify RNG because there is no mention of gaseous fuels, either. The Energy Independence and Security Act of 2007's definitions of renewable fuel, cellulosic biofuel, and advanced biofuel do not include any specifications based on the physical characteristics of the fuel, other than that it is produced from renewable biomass, used in a motor vehicle, and results in certain greenhouse gas reductions as compared to the gasoline or diesel it "replaces." The commenter stated that in this respect, again, electricity is identical to RNG. Neither can it be measured in "gallons" but instead "volumes," which in both cases are determined to be in "gasoline gallon equivalents." The commenter noted that equivalence values for electricity were determined fifteen years ago in the RFS2 final rule and stated that there are further examples of measuring electricity as a "fuel" for other compliance purposes.

One commenter noted there is nothing in either the original RFS (2005) or the expanded RFS (2007) to suggest that Congress intended to narrow the definition of transportation fuel to exclude electricity. In fact, Congress explicitly included electricity from renewable biomass as a part of the RFS program in 2007. EPA's own regulations in 2010 recognized that electricity from renewable biomass could generate RINs if used as a transportation fuel, and in 2014 the Agency establish initial regulatory pathways for biogas-to-electricity RIN generation. The legislative intent to include electricity is clear and EPA has both the authority and precedent to enact the electric pathway now.

Response:

EPA disagrees with these comments. In addition to the explanation provided in Preamble Section VII, the Agency notes that when it determined, in 2010, that renewable electricity can qualify as a renewable fuel under the RFS program, it did so without undertaking an analysis of the relevant statutory language or requirements.[209] The Agency believes it is appropriate to undertake such an analysis at this time to ensure that ongoing implementation of the RFS program is consistent with Congressional direction. When EPA took a closer look at the relevant statutory provisions, it concluded that the best reading of the CAA is that it does not, in fact, permit renewable electricity to qualify as a renewable fuel.

While EPA acknowledges that electricity can be produced from RFS-qualifying biogas and that its lifecycle GHG emissions may meet the 50% or 60% reduction threshold, it is not renewable fuel because it does not satisfy the independent requirement that it replace or reduce the quantity of fossil fuel present in a transportation fuel. It is conceivable that Congress wanted both to allow biogas-derived fuels to be eligible under the RFS program and to exclude one particular form of biogas-derived "fuel"—electricity—from participating because it does not displace fossil fuel that is present in a motor vehicle or motor vehicle engine. Additionally, the relevant displacement for the purposes of CAA section 211(o)(1)(J) is whether something replaces or reduces the quantity of fossil fuel that is present in a transportation fuel, not whether it replaces an obligated fuel (gasoline or diesel). As explained in Preamble Section VII, the definition of renewable fuel makes clear that the relevant scale and location for displacement of fossil fuel is in a motor vehicle, not in the overall U.S. transportation fuel supply, in an electric generating unit, or on the electricity grid.

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[209] 74 FR 14670, 14686 (March 26, 2010).

EPA continues to believe that the statute's references to "volumes" and "gallons" indicates its intent to exclude electricity, which cannot be expressed in these terms. The Agency acknowledges that it uses equivalence values in the RFS program in order to assign RINs to different types of renewable fuel based on their energy and renewable contents. EPA also acknowledges that it has had an equivalence value for electricity in the RFS regulations since 2010.[210] However, the fact that electricity can be converted to a gallon equivalent based on a formula does not change the fact that the statute uses language indicating that Congress was considering biofuels that can be expressed in volumes and gallons. That is, the fact that a regulatory workaround is available does not override Congress's use of terms that show it intended the RFS program to cover fuels that exist as physical volumes. Additionally, EPA disagrees that electricity is "identical to" RNG in this respect—RNG is a tangible chemical substance with mass and volume that can be physically stored and measured. CNG can be measured in pounds, and LNG can be measured in gallons.

When Congress revised the definition of renewable fuel in the 2007 Energy Independence and Security Act (EISA), it broadened the universe of biofuels that could potentially qualify under the RFS program. However, EPA disputes that the current definition includes "*any* fuel for use in *any* type of motor vehicle." While it is true that renewable fuel is not, under EISA's revised definition, restricted to a replacing or reducing fossil fuel in a "fuel mixture used to operate a motor vehicle," it still must be "used to replace or reduce the quantity of fossil fuel present in a transportation fuel." While the limitations of the 2005 definition have been loosened by EISA, it is not the case that anything used in a motor vehicle can be renewable fuel. As explained in Preamble Section VII, a renewable fuel must be physically and actively involved in replacing a measurable unit of fossil fuel that is present in a motor vehicle.

Comment:

Multiple commenters argued that EPA's proposed interpretation of the statute is not consistent with the statutory intent or the plain terms of the statute. Commenters noted that the definition of "renewable fuel" in CAA section 211(o)(1)(J) is broad and includes electricity produced from renewable biomass. One commenter stated that statutory interpretation depends on the context of the definition of renewable fuel and the overall structure of the program. CAA section 211(o)(2)(A)(i) requires that "transportation fuel sold or introduced into commerce" contains the applicable volume of renewable fuel, not the transportation fuel *used*. Several commenters noted that Congress adopted a broad definition of transportation fuel to include "fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels)." CAA section 211(o)(1)(L). "Motor vehicle" broadly encompasses "any self-propelled vehicle designed for transporting persons or property on a street or highway"—a definition inclusive of internal combustion engines vehicles, natural gas-powered vehicles, and electric vehicles. CAA section 216(2). The key is that the fuel reduces or replaces fossil fuel in the transportation fuel market, not in any particular physical gallon or any particular vehicle. Fuel produced from biogas that powes an electric vehicle is a renewable fuel under a simple reading of the statute.

[210] 75 FR 14670, 14869 (March 26, 2010).

A commenter stated that EPA has long recognized the ability to use "neat" renewable fuel (*i.e.*, without blending with fossil fuel) because it displaces use of fossil-based gasoline or diesel fuel. Use of renewable electricity also reduces fossil-based gasoline and diesel fuel use. The commenter argued that this, contrary to EPA's new interpretation, is actually consistent with the inclusion of biogas in the definition of advanced biofuel where EPA's lifecycle GHG emissions reduction analysis is based on displacement of gasoline or diesel, not natural gas.

The same commenter also stated that it is irrelevant that renewable electricity and gasoline or diesel may be used in different types of motor vehicles or rely on different types of engines. They noted that plug-in hybrid electric vehicles use both electricity, which may be charged through the grid, and liquid fuels for their operation. Running on electricity allows less use of the petroleum-based fuel in these vehicles, thereby "physically displac[ing] a volume of fossil fuel that is present in a motor vehicle." The commenter stated that EPA's interpretation constituted arbitrary line drawing and offered a further example of a new engine designed to run on 100% ethanol. There is no question that Congress viewed ethanol as a renewable fuel. However, under EPA's reading, the ethanol used in such an engine would not physically displace fossil fuel used in a motor vehicle because it was not designed to run on gasoline. Any ethanol used to power those vehicles would not be considered renewable fuel, despite Congress's clear inclusion of ethanol in the program.

The commenter stated that it is not clear the line EPA is drawing with respect to its new definition of "transportation fuel" as it applies to renewable electricity. The commenter noted that while EPA recognizes that CNG/LNG is not implicated by the Agency's new interpretation of the statute, its reading draws an incomprehensible line that might impact other biogas-derived fuels that should be eligible under the program. As such, the commenter strongly opposed EPA's proposal to remove renewable electricity from the RFS program.

Another commenter asserted that renewable electricity fits the definition of renewable fuel in CAA section 211(o)(1)(J) because it will replace or reduce the quantity of obligated fuel present in transportation fuel, just as RFS fuels such as ethanol or renewable natural gas.

Response:

As explained in Preamble Section VII and elsewhere in this section, although the definition of renewable fuel is relatively broad, it remains limited to biofuels that physically replace or reduce amounts of fossil fuel. Additionally, the definition of renewable fuel provides that such fuel must replace or reduce the quantity of fossil fuel present in "a" transportation fuel. Congress's use of the article "a" reinforces that the displacement of fossil fuel must take place in an identifiable volume of transportation fuel, rather than in the transportation fuel supply in the abstract. EPA therefore disagrees that the relevant displacement of fossil fuel is in the transportation fuel market—it must be in a specific, identifiable volume of transportation fuel.

EPA recognizes that "neat" biofuels can qualify as renewable fuel. For the purposes of satisfying the definition of renewable fuel, a biofuel must be capable of replacing or reducing the quantity of fossil fuel that is present in a transportation fuel in a motor vehicle. Ethanol clearly meets these requirements, such that it would be fungible with fossil fuel in a motor vehicle or motor vehicle engine. Renewable diesel also meets this requirement, as a renewable fuel that is fully fungible with fossil fuel in a motor vehicle engine. Electricity is not. With regard to plug-in hybrid vehicles, the Agency emphasizes that any renewable electricity used replaces or reduces the fossil-derived electricity that would have been used when the vehicle is operating on its battery. The electricity is not, however, replacing fossil-based gasoline in a direct and quantifiable manner. Displacement of fossil-derived electricity is not, as explained elsewhere, the relevant displacement for purposes of determining whether something is a renewable fuel. Electricity derived from qualifying biogas replaces or reduces fossil fuel in an electric generating unit, not in a motor vehicle. That is, EPA disagrees that any "renewable electricity" used in a plug-in hybrid motor vehicle replaces or reduces gasoline; rather, it replaces or reduces fossil-derived electricity in such a motor vehicle.

Comment:

A commenter stated that EPA has a legal basis to conclude that electricity can meet the "physical displacement" test since electricity derived from biomass can displace electricity derived from fossil sources. Further, according to the commenter, EPA can point to the fact that there is no physical displacement test in the statute. The reason is that renewable fuels are *presumed* to replace "gasoline or diesel" when they are introduced into commerce as transportation fuels, an assumption that Congress built into its calculation of "baseline lifecycle greenhouse gas emissions." CAA section 211(o)(1)(C). Just like RNG, renewable biomass-based electricity used in electric vehicles displaces gasoline and diesel by "reducing" the precent of fossil fuel in the *aggregate* across the country's transportation fuel supply—the level at which Congress directed EPA to ensure that fossil fuels are displaced by renewable biomass-based fuels.

The commenter stated that a qualified fuel need not be "present in transportation fuel" and "contained" within the fuel as opposed to a "substitute." If that were the law, RNG could not qualify. It is physically impossible to blend "biogas" with conventional gas in an engine. In 2014, EPA changed the definition of "fuel" form "biogas" to "renewable LNG and renewable CNG." EPA allowed RNG to become a fuel only by abandoning a physical displacement test in favor of a virtual contract approach, and allowing the attributes of cleaned up biogas to be contractually pathed with conventional CNG and LNG.

Response:

EPA responds to this comment in Preamble Section VII and elsewhere in this section. The Agency emphasizes that, under the best reading of the definition of renewable fuel, the relevant displacement is the replacement or reduction of fossil fuel—not limited to gasoline or diesel—that is present in a transportation fuel. EPA disagrees with the commenter that a renewable fuel need not be capable of being present in a fossil-based transportation fuel.

Additionally, EPA notes that the "virtual contract approach" to which the commenter refers is a different matter that concerns how RNG is tracked and how parties demonstrate that pipeline RNG is used for transportation. This "book-and-claim" approach is an implementation tool that is not relevant to the definitional inquiry of whether a biofuel replaces or reduces a physical quantity of fossil fuel that is present in a transportation fuel. As explained elsewhere, fossil natural gas is a fossil fuel and renewable CNG/LNG can physically replace or reduce fossil natural gas that is present in a motor vehicle. Renewable CNG/LNG therefore qualifies as a renewable fuel (assuming the other relevant requirements are also met).

Comment:

A commenter pointed to the evolution of the statutory definition of "renewable fuel" from when it was defined by Congress in the 2005 Energy Policy Act, then revised in 2007 in the Energy Independence and Security Act, and how, in 2025, EPA proposed to interpret the 2007 definition. The commenter said that the still operative 2007 revised definition of renewable fuel, combined with the definition of transportation fuel, is as follows: renewable fuel means 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, *i.e.*, in a fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels). The commenter continued that EPA's proposed best reading of the 2007 statutory definition reads as follows: renewable fuel means a fuel, *i.e.*, a material used to produce heat or power by burning, that is produced from renewable biomass and that is used to physically displace a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine.

The commenter stated that EPA's best reading is misguided and arbitrary. It limits renewable fuels to only those that: (i) constitute a "material," (ii) are used to produce heat or power by burning, and (iii) are used to "physically displace a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine" (instead of "*used to replace or reduce the quantity of fossil fuel present in a transportation fuel*"). Given that the only two obligated fuels subject to replacement or reduction under the RFS program are gasoline and diesel, that reading would appear to limit renewable fuels to only liquid renewable fuels that are fungible with either of those two liquid fossil fuels in a motor vehicle or engine.

The commenter stated that grid electricity, which inevitably includes fossil electricity, is being used in a significant number of electric vehicles and is therefore now displacing a significant amount of gasoline. Renewable electricity is perfectly fungible with grid electricity, and it can certainly be used to displace any grid electricity used in those vehicles. But if renewable electricity is produced with biogas and used in electric vehicles in accordance with RFS regulations, it will be used just as grid electricity is now being used, *i.e.*, to displace gasoline.

The commenter further noted that EPA provided information in its draft Regulatory Impact Analysis for the Set 2 proposal concerning the ability of electricity to displace petroleum fuels and reduce their consumption. In the draft RIA, EPA stated that electric vehicles and plug-in hybrid electric vehicles reduce consumption of petroleum fuel by either partially displacing petroleum fuels (in the case of PHEVs) or completely displacing petroleum demand (in the case of EVs). EPA also estimated the gallons of gasoline displaced by EVs and PHEVs. The commenter stated that this is one fuel – electricity – replacing or reducing the quantity of another fuel – gasoline – present in a transportation fuel, *i.e.*, in motor vehicle fuel.

The commenter summarized by stating they believe that renewable electricity is a fully qualified RFS renewable fuel, and the best reading of the CAA definition of renewable fuel should incorporate: (i) language of the statutory definition of fuel included in the Automotive Propulsion Research and Development Act of 1978, (ii) language from the statutory definitions of "renewable fuel" and "transportation fuel" included in the CAA, and (iii) the term "obligated fuel" as it has been used by EPA, as follows: Renewable fuel means any energy source capable of propelling a motor vehicle that is produced from renewable biomass and that is used to replace or reduce the quantity of obligated fuel present in a transportation fuel (*i.e.*, present in a fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels)).

Ethanol, renewable diesel, and RNG all replace or reduce the quantity of obligated fuel present in a transportation fuel. Renewable electricity will likewise replace or reduce the quantity of obligated fuel present in a transportation fuel. As such, renewable electricity fully qualifies as RFS renewable fuel and should not be removed from the RFS program.

Response:

EPA responds to this comment in Preamble Section VII and elsewhere in this section. The Agency also notes that its statement regarding electric vehicles reducing petroleum fuel consumption in the DRIA was part of an overview of transportation fuel demand. While consideration of the impacts of vehicle electrification on such demand is relevant to EPA's review of the implementation of the RFS program (which is the context of this discussion in the DRIA), it is not pertinent to determining whether electricity from renewable biomass can satisfy the statutory requirements to be a renewable fuel. That is, the DRIA merely discussed the factors that have contributed to lowering transportation fuel demand, which is relevant to assessing the impacts of implementation of the RFS program.

Additionally, the Agency disagrees that the term "obligated fuel" is interchangeable with "fossil fuel" in CAA section 211(o)(1)(J). "Obligated fuel" is not a defined term in the statute and it does not appear in CAA section 211(o)(1)(J). That provision uses the phrase "fossil fuel present in a transportation fuel." As explained elsewhere, EPA interprets this phrase to refer to any type of fossil fuel, including gasoline, diesel, and fossil natural gas, that is physically present in a transportation fuel in a motor vehicle.

Comment:

Several commenters supported EPA's decision to move away from the eRINs program it proposed in the December 2022 Set 1 rulemaking. One commenter stated that they opposed the Set 1 electricity proposal based on the material changes that proposal would have had on the RFS program, and because it was never Congress's intent to include electricity in the RFS program. However, this commenter also noted that they believe that EPA's analysis for completely disallowing electricity to be considered a renewable fuel is flawed and that the rationale presented could also be used to exclude other non-liquid renewable fuels from the RFS program. Another commenter similarly agreed that EPA's past eRINs proposals were wholly inconsistent with both the existing RFS regulations and the statute and supported abandoning the Set 1 proposal. This commenter stated that if EPA is unable to design a reliable eRIN system that is consistent with the regulatory history and statutory requirements of the RFS program, then entirely removing electricity from the program may be the most prudent approach. A third commenter supported EPA's recognition that electricity was not contemplated by Congress as part of the RFS framework, as well as the Agency's decision to move away from the previous proposal. This commenter also stated that they believed EPA's rationale for fully excluding electricity from consideration as a renewable fuel warrants further examination.

Response:

EPA acknowledges these comments.

Comment:

A commenter stated that RNG and biogas producers have long anticipated EPA finalizing regulations to allow for generation of RINs for renewable electricity, relying on a long-established and previously unquestioned belief that renewable electricity qualified under the RFS program. This reliance has supported business decisions, particularly with respect to what to do with projects that have expiring power purchase agreements.

Response:

EPA acknowledges this comment. However, the Agency has taken the position since 2016 that the regulations it issued between 2010 and 2014 cannot support implementation of a renewable electricity program, and it has never registered any party to generate RINs for renewable electricity. While EPA did propose new regulations that would have governed RIN generation for renewable electricity in 2022, it then declined to finalize these regulations with the rest of the Set 1 Rule in 2023. Given the longstanding dormancy of the program, we do not believe that parties could have reasonably and substantially relied on it to support business decisions.

10.2 General Comments on Removal of eRINs

Comment:

Multiple commenters expressed support for the exclusion of eRINs from the RFS program. A commenter stated that incorporating eRINs into the RFS program has the potential to have significant and negative unintended consequences for future renewable jet fuel and other renewable fuel supplies. The commenter stated that a viable renewable jet fuel market cannot be developed without a vibrant and viable renewable fuels industry and encouraging the diversion of current and potential future feedstocks and RINs towards electricity production would inhibit the development of that market.

Response:

EPA acknowledges these comments and is finalizing the removal of renewable electricity from the RFS program for the reasons laid out in Preamble Section VII.

Comment:

A few commenters highlighted their concerns over the potential negative impacts which could potentially accrue to America's forested habitats if EPA were to allow electricity in the RFS program and also allow for the generation of RINs for electricity produced from woody biomass. Under these circumstances, they expressed concerns that electricity in the RFS program could cause ecological harm to forests and would incent biomass electricity over non-emitting electricity sources.

Response:

EPA acknowledges these comments and is finalizing the removal of renewable electricity from the RFS program for the reasons laid out in Preamble Section VII.

Comment:

EPA received many comments in opposition to the program for including electricity in the RFS program which was proposed in Set 1. One commenter stated that there are two fundamental flaws with the Biden era eRIN proposal: (1) the complexity of the program, and (2) the designation of OEMs as the RIN "producer," thus creating a subsidy that was never intended and not consistent with the law. The commenter suggested that EPA amend the current law by designating the generator of electricity from renewable biomass as the RIN generator, and explicitly eliminate the ability of OEMs to generate RIN credits. This would align the program with existing law and with the intent of Congress.

Another commenter noted that they previously opposed EPA's proposed eRIN program from the RFS Set 1 proposed rule; however, their opposition was largely focused on the material changes that this proposal would have had on the program – namely, changing the RIN generator for one specific fuel. The commenter noted that the structure of the proposed eRIN program would have deviated from the existing structure of the RFS program in which the renewable fuel producer is the RIN generator compared to other renewable fuels.

Response:

EPA acknowledges these comments. EPA agrees that the complexity and inability to implement the program is another reason why electricity was not intended to be included within the RFS program. Because the Agency is now finding that it lacks a statutory basis for including renewable electricity in the RFS program, the previous proposal is moot. Additionally, to ensure there is no confusion amongst RFS stakeholders about the status of the Set 1 proposal for the inclusion of renewable electricity in the RFS program, we are withdrawing the previously proposed program as part of this final rule. For additional details on the withdrawal, please refer to Preamble Section VII and elsewhere in this section.

Comment:

A related topic which received a substantial quantity of comments, from parties interested in keeping electricity part of the RFS program, was suggestions and critiques about how EPA should design an eRIN program were electricity kept in the RFS program. The majority of these comments focused on either the type of data which should be used for RIN generation or which parties in the biogas electricity to transportation use value chain should be permitted to be the RIN generator. We have summarized a few of these themes in the following paragraphs:

One commenter suggested that EPA simplify the program by allowing all registered facilities to participate, and award a RIN based on the fraction of electricity consumed for transportation over the amount of qualified generation. The commenter stated that, under their proposal, EPA would, on an annual basis, establish both the consumption and generation, and establish a fraction of a RIN that would then be generated by registered producers.

Another commenter noted that they provided substantive comments on how EPA could implement the eRINs program in a way that would, as Congress intended, support increased production of cellulosic biofuels (*e.g.*, RNG). The commenter, along with another commenter, stated that they opposed the previous Administration’s proposal to have the original engine manufacturers be the RIN generators. These commenters argued that the electricity producers or charging station operators should be allowed to generate RINs

A commenter stated that there is no technical barrier to implementing the eRIN pathway. The commenter stated that renewable electricity can be metered, tracked, and verified for use in electric vehicle charging. While some have claimed in the past that administering electric RINs would be complex, the commenter said that these challenges can be managed with available technology and sound oversight, just as other environmental credit programs handle measurement and fraud prevention.

A commenter urged EPA to retain renewable electricity as an eligible pathway under the RFS program and suggested the establishment of third-party verification pathways for electricity derived from biomass that is aggregated, chipped, or transported in bulk from restoration units. The commenter said that this would reduce compliance burdens while maintaining RIN integrity.

Another commenter said that EPA should activate the eRIN pathway and let electricity producers generate RINs. The commenter said that credit generation should be tied to delivered transportation energy rather than specific vehicle makers.

Response:

Competing and disparate arguments over how best to incorporate electricity into the RFS program have been presented to EPA for over a decade. The lack of consensus surrounding if, and by what means, EPA should have implemented electricity in the RFS program was always a substantial impediment to the successful inclusion and implementation of renewable electricity in the RFS program. The inability to establish a consensus around implementing electricity within the RFS program is another example of why Congress never intended electricity to be included within the RFS program. However, as articulated is Preamble Section VII and elsewhere in this section, we are removing renewable electricity from the RFS program based upon statutory interpretation.

Comment:

Several commenters raised concerns over EPA removing electricity from the RFS due to the adverse impact that may be felt by small RNG producers (*e.g.*, farmers and dairies) not being able to participate in the RFS program as currently constructed.

According to commenters, eRINs create markets for underutilized biomass, such as landfill gas and agricultural waste, supporting rural economies and American farmers. EPA's prior analyses (2023–2025 rulemaking) acknowledged eRINs' potential to boost cellulosic biofuel use, a category consistently below statutory targets. Organizations like the American Biogas Council, Partnership to Electrical Pathways, RNG Coalition, and oil companies (*e.g.*, BP) have expressed strong support for eRINs, citing their ability to drive investment in renewable energy infrastructure. Removing eRINs eliminates these economic opportunities, contradicting EPA's commitment to rural communities and stakeholder feedback from the 2023 rulemaking.

Commenters asserted that electricity produced from biogas enables an entire sector of potential fuel producers to access the transportation market. RNG derived from biogas is not always cost-effective, due to lack of gas infrastructure or due to lack of scale to support the expensive upgrading equipment needed. The commenters stated that electricity from biomass fills this sizeable gap in market access, which disproportionately impacts farmers and rural communities where gas infrastructure may be limited, or where farms and rural wastewater systems are too small to support the expense of RNG production. Pathways that recognize biogas derived electricity allow these small farms and small rural communities to benefit from the RFS program. Without an electric pathway, commenters argued, these opportunities are lost.

Response:

As correctly pointed out by commenters, EPA has, in the past, acknowledged that there are structural reasons why adding renewable electricity to the RFS program would likely enable smaller and/or remote biogas producers to benefit from the RFS program. However, given that EPA has taken the position since 2016 that the regulations it issued between 2010 and 2014 cannot support implementation of a renewable electricity program and that the Agency has never registered any party to generate RINs for renewable electricity, we do not believe any small and/or remote biogas producers will incur a material loss as a result of this action. EPA stresses that it is not taking this action on policy grounds. Rather, as articulated in Preamble Section VII and elsewhere in this section, we are removing renewable electricity from the RFS program because it does not satisfy the fundamental statutory requirements to qualify as a renewable fuel.

Comment:

Commenters argued that the elimination of electricity from the RFS program will stifle innovation and exclude fuel sources which could otherwise qualify for the RFS program. These commenters believe EPA should reconsider the removal of electricity from the RFS program and that participation in the program could play a crucial role in promoting the development and production of renewable electricity derived from biomass. These commenters assert that by removing electricity from the program, EPA will stifle innovation, reduce energy security, and potentially exclude other fuel sources.

There was a broad range of comments which relate to this general theme of benefits which may not be achieved if electricity is not part of the RFS program. For instance, a commenter said that the inclusion of eRINs in the RFS program provides additional incentives for publicly owned treatment works to recover energy from their continuous, renewable supplies of municipal wastewater and biosolids. Production of renewable electricity through recycling of this organic material will contribute to the nation’s energy independence, according to the commenter.

Another commenter stated that retaining eRINs would incentivize landfill gas-to-electricity projects that support electric vehicles and reduce air emissions, aligning with the RFS program’s environmental goals and EPA’s role in protecting the environment. There were many comments which conveyed a similar message: eRINs should be used to support baseload electricity generation from many forms of renewable biomass which would support energy dominance and reduce imports, etc.

Other commenters provided arguments which were in support of keeping electricity in the RFS program but focused on other potential associated benefits. For instance, a commenter stated that maintaining the pathway for renewable electricity strengthens U.S. supply chains and provides certainty for grid modernization. The commenter also said that electric vehicle batteries present unique opportunity for advanced energy independent, global economic competitiveness and defense readiness in the U.S. the commenter recommended that EPA retain the existing regulatory provisions in 40 CFR 80.1426(f)(10)(i) to enable future pathways for renewable electricity and eRINs, at minimum for biogas and waste digesters.

Response:

EPA acknowledges these comments. While the Agency takes no position on their merit, it further acknowledges that a potential renewable electricity program could play various roles and have a range of impacts. However, EPA emphasizes that it has never implemented the existing renewable electricity regulations under the RFS program or registered any party to generate RINs for renewable electricity. Any benefits are therefore hypothetical. EPA also stresses that it is not taking this action regarding renewable electricity in the RFS program on policy grounds. Rather, as articulated in Preamble Section VII and elsewhere in this section, we are removing renewable electricity from the RFS program because it does not satisfy the fundamental statutory requirements to qualify as a renewable fuel.

Comment:

EPA received many comments on the topic of woody biomass and the potential benefits which keeping electricity in the RFS program and allowing for certain types of woody biomass to generate eRINs may provide.

One commenter stated: Recent years have seen the U.S. forest products industry collapse, with dozens of sawmill and biomass power facility closures. With his Timber Expansion Executive Order, President Trump is attempting to reinvigorate the forest products sector. A key component of this is to ensure that there are markets for wood residues, the largest of which is the U.S. biomass power sector. As the EO states, “bioenergy is critical to the nation’s well-being.” Enabling sawmill residues to qualify will help to create a new revenue stream for struggling sawmill operators, and it will put discarded fibers that have no other use to work in biomass power facilities. Allowing biomass electricity to participate in the RFS would help accomplish the goals set by President Trump’s executive order, and it would improve the economic competitiveness of 24/7 renewable technologies like biomass.

Another commenter stated that woody biomass provides reliable, safe, dispatchable baseload power that is critical for large factories. The commenter stated that using biomass for energy has the same in-forest, economic and carbon benefits as using wood for biofuels. With some modifications, the commenter said that the RFS program could incentivize utilization of more biomass to strengthen domestic electrical energy production.

Similarly, other commenters said that electricity inclusion in the RFS program would support much needed wood markets and baseload power generation. Some commenters stated that retaining eRINs for fuel derived from wood and forest residues sources from Federal lands would help clear out the buildup or “hazardous ladder fuels” from high-risk forests, help reduce enormous costs associated with catastrophic wildfires, and support forest health.

Lastly, a commenter stated that by excluding electricity from the RFS program, the proposed rule may unintentionally discourage or devalue Tribal energy initiatives that directly align with Federal and State drought and wildfire prevention and goals.

Response:

EPA notes that there has never been an approved pathway in the RFS program for the generation of renewable electricity using woody biomass. EPA is not acting to remove electricity from the RFS program on policy grounds. Rather, as articulated in Preamble Section VII and elsewhere in this section, we are removing renewable electricity from the RFS program because it does not satisfy the fundamental statutory requirements to qualify as a renewable fuel.

11. Amendments to the RFS Program Regulations

11.1 Renewable Diesel, Naphtha, and Jet Fuel Equivalence Values

Comment:

Several commenters expressed support for EPA's decision to revise equivalence values to account for non-renewable content in certain fuels. A commenter expressed support for EPA's decision to change the equivalence value for renewable diesel, naphtha, and jet fuel while not offering a new definition for "produced from renewable biomass" to maintain a broad and flexible approach to the definition. In particular, a commenter expressed support for EPA's simplified approach of changing the equivalence value by a fixed amount rather than requiring batch-by-batch analysis to determine the qualified proportion of renewable content. A commenter stated that the 1.6 baseline equivalence value for renewable diesel aligns with the energy content of the renewable diesel and hydrogen bonds in the finished fuel.

Response:

In this action we are finalizing changes to the equivalence values for renewable diesel, naphtha, and jet fuel. The equivalence values we are finalizing are based on our updated analysis and consideration of the comments received on the proposed rule and take into account the portion of these fuels that is derived from renewable biomass and the energy content of these fuels.

Comment:

A commenter expressed support for EPA's revision of the equivalence value for renewable diesel to account for fossil hydrogen in the fuel production process. Another commenter supported an adjusted equivalence value for renewable diesel based on lower renewable content due to fossil hydrogen used in fuel production. The commenter supported the adoption of a 1.6 equivalence value for renewable diesel with a minimum energy content of 123,800 BTU per gallon. The commenter also supported downward revisions for renewable jet fuel (to 1.5) and renewable naphtha (to 1.4) based on non-renewable energy content.

Response:

The equivalence values we are establishing in this rule for renewable diesel (1.5), renewable jet fuel (1.5), and renewable naphtha (1.4) based on our updated analysis are generally consistent with the recommendations from this commenter. Based on input from commenters and a review of the available data, we revised our technical assessment of properties of UCO. Our previous technical assessment has treated UCO as more similar to tallow and animal fats (with fewer unsaturated bonds). Our analysis for this final rule treats used cooking oil as more similar to vegetable oil (with relatively more unsaturated bonds) as vegetable oils are the primary source of used cooking oil in the U.S. We also updated our estimates of the feedstock mix likely to be used to produce renewable diesel based on more recently available information. Renewable diesel producers that produce fuel that meets a minimum energy content specified by EPA in the technical memorandum may submit an application under 40 CFR 80.1415(c) for an equivalence value of 1.6.[211]

Comment:

A commenter expressed concern that the equivalence value for renewable diesel is unlawful, the proposal perpetuates existing bias favoring renewable diesel, and that D4 and D5 RIN prices do not accurately reflect the market for these fuels and RINs. The commenter stated that EPA has not provided its methodology for approving equivalence values, and urged EPA to revise the equivalence values for renewable diesel as soon as possible to help renewable fuel displace fossil fuel.

Response:

Our calculation of equivalence values is based on a clear methodology established in 2010.[212] The equivalence values we are finalizing in this rule for renewable diesel, jet fuel, and naphtha use this same methodology, but the calculations have been updated to properly reflect the contribution of non-renewable hydrogen to the energy content of these fuels. The equivalence values for these fuels we are finalizing in this rule are based on the same methodology as the RFS2 Rule in 2010 and the Set 2 proposal, but with slightly updated inputs into the formula for calculating the equivalence value. Under the RFS program, the equivalence values account for both the renewable content of the qualifying fuel and the energy content of the fuel.

Comment:

A few commenters expressed concern regarding EPA's use of higher heating values for determining combustion energies and lower heating values for the equivalence value calculation, leading to an inconsistent comparison basis.

Response:

For estimating the renewability of renewable diesel, naphtha, and jet fuel in the Set 2 proposal analysis, the heat contents of the various hydrocarbons produced from the renewable diesel reaction process, and its hydrogen content, were inadvertently based on higher heating values. The commenter correctly points out that this is inconsistent with the use of lower heating values required elsewhere. For calculating the renewability of renewable diesel, naphtha, and jet fuel for the final rule, all heating values used are lower heating values.[213]

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[211] See "Calculation of Equivalence Values and Energy Content for Renewable Diesel, Naphtha, and Jet Fuel for Set 2 FRM," available in the docket for this action.
[212] 75 FR 14670 (March 26, 2010).
[213] We note that since higher heating values were used consistently (for both the products and reactants) for the Set 2 proposal, the shift to lower heating values for both feedstocks and products in the final rule caused only minor differences in renewability values compared to those estimated for the proposal.

Comment:

A commenter stated that EPA's consideration of hydrogen as a feedstock is inappropriate and inconsistent with well-established principles of GREET, California Air Resources Board, and International Civil Aviation Organization lifecycle analyses upon which the RFS program relies. The commenter further stated that EPA's proposed method to determine renewability "is not settled science," discussed the flaws in four different methods to calculate renewability, and suggested that EPA consider the motivations of other proposals previously submitted to EPA for determination of renewability. The commenter recommended that EPA not proceed with the proposed equivalence value reductions.

Response:

The calculation of the renewable content of fuels under the RFS program is used to determine the appropriate equivalence value for qualifying fuels. In contrast, the calculation of the lifecycle GHG emissions of fuels (which can be estimated using GREET and other methods mentioned by the commenter) are used to determine whether fuels produced from renewable biomass meet the statutory criteria established by Congress for each type of renewable fuel in the RFS program. While there are some similarities between these two calculations, they are not the same nor are they used for the same purposes. For example, a fuel produced from waste plastics could have no renewable content but very low lifecycle emissions. Conversely, a fuel produced from agricultural residue with very high fossil energy inputs in the fuel production process could have high renewable content and very high lifecycle GHG emissions. These two calculations serve different purposes in the RFS program and are not interchangeable. The use of methods to estimate lifecycle GHG emissions are not appropriate for estimating the renewable content of renewable diesel, naphtha, and jet fuel.

The use of the energy content of feedstocks to a renewable diesel reactor is consistent with how the renewability of biodiesel was calculated. Since biodiesel and renewable diesel compete for both feedstocks and market share under the RFS program, it is important to use a consistent methodology for the two processes to avoid arbitrarily favoring one either of these fuels over the other. For calculating the renewability of biodiesel, we account for the use of non-renewable methanol in the production process. Accounting for the non-renewable hydrogen in production process for renewable diesel (and jet fuel and naphtha) is therefore using a consistent methodology to calculate the renewable content and equivalence values across these fuels.

For producing renewable diesel fuel, all renewable diesel plants feed their renewable diesel reactors with hydrogen, so this is the primary feedstock that could be used for calculating the renewability of renewable diesel. As indicated by the commenter, EPA also considered other methodologies that treated fossil natural gas (from which hydrogen is produced) or hydrogen produced in the reforming process as a feedstocks for the production of renewable diesel rather than the hydrogen produced from natural gas. In many cases, renewable diesel plants have a hydrogen plant to produce the necessary hydrogen, and in that case the natural gas feedstock to the combined hydrogen plant and renewable diesel plant could be considered a renewable diesel feedstock. However, some other renewable diesel plants purchase their hydrogen from third-party producers. In that case, the renewable diesel plant operator does not know how the hydrogen plant is operated, including the feedstock used. Hydrogen can be produced from natural gas, naphtha, or even coal. In another case, a renewable diesel facility (collocated at a petroleum refinery) likely obtains some, if not all, of its hydrogen from a reforming unit at the refinery. Estimating the renewability if the hydrogen is produced from a reformer is complicated depending on how the refinery is producing the hydrogen at refinery's reformer, which can vary over time. Due to these complexities, we simplified the renewability calculation for renewable diesel, naphtha, and jet fuel to be solely based on the hydrogen feedstock to the renewable diesel plant.

Comment:

A commenter discussed discrepancies in the proposed rulemaking between the text and attachments referenced regarding equivalence values. The commenter identified specific issues with the renewable naphtha value listed in the technical memorandum, which the commenter expressed was lower than expected given the renewable diesel methodology. The commenter also pointed out inconsistencies in the rounding convention used for equivalence values. Relatedly, a commenter stated that EPA's proposed equivalence values for renewable naphtha and jet fuel are not consistent with the values described in the technical memorandum.

A few commenters conducted a detailed analysis of EPA's calculations in the technical memorandum and identified several issues. The commenters found that the theoretical energy content calculated using the heat of combustion methodology for renewable diesel is 121,780 Btu/gal, which aligns with EPA's previously accepted value of 122,000 Btu/gal, but EPA increased it to 123,800 Btu/gal without substantial proof. Another commenter developed a corrected version of the technical memorandum that corrects minor math errors, provides "more realistic" heating values, and presents new considerations for the renewability value.

The commenters also expressed concern that EPA's assumptions about C14 and C16 hydrocarbons do not reflect current commercial renewable jet fuel production practices. The commenters stated that when a representative composition of C9 to C16 molecules is used with the 122,000 Btu/gal energy content, the equivalence value for renewable jet fuel should be 1.43, which rounds down to 1.4.

Response:

We have revised and updated our technical memorandum based on additional information and consideration of public comments. The equivalence values in this final rule are consistent with our updated technical analysis. As discussed in Preamble Section VIII.A, we are aware that the energy content (and thus the appropriate equivalence value) for renewable diesel can vary depending on a number of factors. To account for this variation, we are establishing a default equivalence value for renewable diesel that is consistent with EPA's technical evaluation and allowing parties to apply for a higher equivalence value based on energy content testing if appropriate. While there is also variation in the energy content of renewable jet fuel and naphtha, our analyses indicate that this variation is unlikely to be of such a magnitude that an equivalence value different than those we are finalizing in this rule would be appropriate. Parties that produce renewable jet fuel or naphtha with higher energy content or renewable content that would merit a higher equivalence value may apply for a higher equivalence value under 40 CFR 80.1415(c).

Comment:

A couple of commenters discussed that EPA's proposed reduction in equivalence values fails to account for a common production process where hydrodeoxygenation offgas and propane are rerouted back to the hydrogen plant, leading to an overestimation of the impact of non-renewable portions to equivalence values. The commenter urged EPA to adjust the equivalence values to account for this.

Response:

We considered the potential impact of using offgas or propane to produce a portion of the renewable hydrogen used in the production of renewable diesel, naphtha, and jet fuel. At this time, we lack information on the extent of this practice in the production of these fuels. It is also unclear what portion of the overall hydrogen used in the production of these fuels is sourced from renewable offgas or propane at facilities that are generating hydrogen from these processes. The equivalence values we are finalizing in this rule do not account for hydrogen produced from renewable offgas or propane; however, parties that use hydrogen from these sources may include this information and an estimate of the impact on the renewable content of the fuels they produce when applying for a higher equivalence value under 40 CFR 80.1415(c).

Comment:

A few commenters argued that EPA's feedstock mix assumptions for determining the equivalence value for renewable diesel incorrectly replaced the entire UCO and DCO contribution with tallow, which unfairly pushes the renewable diesel equivalency value higher. The commenters suggested that UCO should be represented as a blend of SBO and tallow, and DCO should be represented as corn oil. The commenters stated that this feedstock mixed and using the 122,000 Btu/gal energy content results in an equivalence value of 1.5 for renewable diesel.

Response:

For the final rule, we performed additional investigation into the sources of UCO. We determined that the majority of UCO used in biofuel production in the U.S. is vegetable oils rather than animal fats such as tallow.[214] In our updated technical analysis, we have projected that biofuel produced from UCO has the same renewable content as biofuel produced from the original virgin vegetable oils. This has the effect of slightly reducing the estimated average renewable content of renewable diesel, jet fuel, and naphtha. The equivalence values we are finalizing in this rule reflect these updated analyses.

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[214] 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.

Comment:

Several commenters expressed concerns about EPA's rounding conventions and the use of default values. A couple of commenters discussed that EPA rounded biodiesel's equivalence value down from 1.54 to 1.5, but rounded renewable diesel's equivalence value up from 1.56 to 1.6, which the commenters argued gives renewable diesel a significant advantage despite the values being much closer than the 0.1 difference in equivalence value. They noted that a 0.1 difference in equivalence value for the 2.98 billion gallons of renewable diesel reported in 2024 results in almost 298 million additional RINs, which at $1.20 per RIN represents a $0.12 advantage per gallon.

Response:

Since EPA established regulations for the revised and expanded RFS2 program in 2010, we have always rounded equivalence values to the nearest tenth of a RIN.[215] Under 40 CFR 80.1415(c)(1), the equivalence value is defined as being "rounded to the nearest tenth." We acknowledge that some precision is lost in the rounding; however, we also note that in many cases it is not practical to require a precise calculation of the equivalence value for each individual facility and feedstock (or mix of feedstocks). This is especially true for technologies like the hydrotreating of renewable feedstocks to produce renewable diesel, jet fuel, and naphtha that produce a range of different fuel molecules. Rounding to the nearest tenth of a RIN per gallon recognizes this uncertainty and reasonably balances the need for precision and a desire not to place overly burdensome regulations on renewable fuel producers. Finally, we note that the equivalence value for renewable diesel we are establishing in this rule has been rounded down to 1.5. Because the equivalence values for both biodiesel and renewable diesel have been rounded down, this rounding convention does not advantage either of these fuels over the other.

Comment:

A couple of commenters argued that setting a default equivalence value of 1.6 for renewable diesel uses the very top end of the range (1.5 to 1.6) when most renewable diesel cannot achieve 1.6 without using the most favorable assumptions and rounding up. They suggested that if renewable diesel producers want to claim a 1.6 equivalence value, which may obtain an additional $0.10 to $0.20 per gallon in RIN generation, they should be required to demonstrate that their fuel meets the threshold energy content of 123,800 Btu per gallon through regular testing.

Response:

In this rule we are setting a relatively default equivalence value for renewable diesel that is consistent with EPA's technical evaluation (1.5) and allowing renewable diesel producers to submit applications for a higher equivalence value if they can demonstrate that they meet the specified energy content threshold. This approach is generally consistent with the commenters' recommendation.

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[215] 75 FR 14710 (March 26, 2010).

Comment:

Several commenters expressed concerns about the timeline for implementing the proposed changes to equivalence values. A couple of commenters argued that EPA's proposal offers almost no time for producers to adapt. The commenters urged EPA to defer the proposed changes to equivalence values to an effective date of 2027 to avoid upsetting commercial expectations, including for feedstock supply and fuel product offtake agreements that extend beyond 2025. One commenter also requested that EPA offer clear, streamlined procedures for producers to establish higher equivalence values for impacted fuels. The commenter suggested that hydrotreated esters and fatty acids fuel producers should be able to demonstrate the proportion of their hydrogen produced from renewable biomass.

Relatedly, a commenter requested a minimum two-year transition period to apply the reduced equivalency values to existing facilities, given the investments already made. The commenter also suggested allowing differentiated values if demonstrated through a pathway petition. A commenter expressed concern that with a final rule being signed in late 2025, affected facilities and EPA would have an unrealistic deadline to submit and accept registration requests. The commenter requested that EPA make a change to EMTS and/or OTAQREG to automatically update affected facility's registration information to utilize the new equivalence values, or streamline the registration process to ensure no disruption in RIN generation.

A commenter requested that EPA delay the change in equivalence values for existing impacted registered RIN generators until more details are provided on how registration updates will be administered. The commenter suggested that all currently registered renewable diesel producers hydrotreating with petroleum-derived hydrogen using the default pathway should be changed no sooner than six months after the rule's effective date.

A commenter recommended an alternative approach to EPA's proposed implementation plan, suggesting that pathways should only be deactivated if a producer does not provide adequate substantiation of the equivalence value within 120 days after the effective date of the rule.

Response:

The changes to the equivalence values for renewable diesel, jet fuel, and naphtha that we are finalizing in this rule will not be effective until January 1, 2027. The delay in the effective date for these provisions will allow renewable fuel producers time to make the necessary adjustments to their contractual arrangements. It will also give adequate time for renewable fuel producers to submit applications with the necessary supporting testing data for equivalence values that are higher than the default values we are finalizing in this rule. Finally, by allowing renewable fuel producers to use the average estimates of the renewable energy content from our technical memorandum, we are significantly streamlining the process for applying for a higher equivalence value. All that will be required of a renewable fuel producer in these applications is testing results verifying the energy content of a representative sample of the fuel they produce for commercial sale.

Comment:

Several commenters advocated for higher equivalence values for renewable jet fuel to incentivize its production. A commenter discussed that EPA has discretion under the CAA to determine the "appropriate" amount of credits generated for the production of a given volume and type of renewable fuel. The commenter urged EPA to use this discretion to set equivalence values to incentivize renewable jet fuel production. Relatedly, a couple of commenters suggested providing preferential equivalence values for renewable jet fuel to better establish the market and create a level playing field given the differing production economics. Alternatively, the commenters suggested that EPA could assign a higher equivalence value to renewable jet fuel that equalizes the assessed production cost disadvantage between renewable diesel and jet fuel produced at the same facility.

A commenter asked EPA to consider adopting a preferential equivalence value of 1.8 RINs per gallon for renewable jet fuel to better establish this market and avoid ceding leadership to foreign competitors. Another commenter expressed support for EPA's use of RIN value and separation of RINs to incentivize domestic feedstocks for renewable jet fuel.

A commenter expressed support for equivalence values of 1.6 for both renewable diesel and jet fuel but suggested increasing the equivalence value for renewable naphtha and jet fuel to 1.8 RINs per gallon, implemented with a sunset of two years. A couple of commenters discussed that a higher equivalence value for renewable jet fuel could support American energy dominance and balance near-term investment with longer-term market opportunities. Another commenter requested that EPA offer clear, streamlined procedures for producers to establish higher equivalence values for impacted fuels, and particularly for hydrotreated esters and fatty acids fuel producers, or allow producers to maintain their currently registered equivalence values for no less than one year from the final rule's effective date.

Response:

Our calculation of equivalence values in the RFS program is based on a clear methodology established in 2010.[216] This calculation is based on the renewable content and the energy content of renewable fuels. To date, we have not increased (or decreased) the equivalence value for renewable fuels based on a consideration of other desirable or undesirable qualities of renewable fuels. Changing our approach to equivalence values would significantly complicate the RFS program, as it would introduce potentially limitless policy considerations into what is currently a simple technical calculation. We do not believe it would be appropriate to deviate from the current methodology of calculating equivalence values based on the renewable content and the energy content of renewable fuels. We also note that the changes requested by these commenters were not a part of our proposed rule and are therefore beyond the scope of this final rule.

Comment:

A commenter opposed any unique pathways for renewable jet fuel until petroleum jet fuel is obligated. The commenter argued that renewable jet fuel producers generate RINs for each

[216] 75 FR 14670, 14710 (March 26, 2010).

gallon they produce, even though petroleum-derived jet fuel producers assume no corresponding obligation, creating a structural asymmetry that threatens to crowd out biofuels for over-the-road applications. The commenter suggested that EPA either initiate a rulemaking to make jet fuel an obligated fuel under the RFS program or remove renewable jet fuel from RFS eligibility. The commenter also expressed support for finalizing a reduced equivalence value of 1.4 RINs per gallon for renewable jet fuel relative to renewable diesel and biodiesel, stating that preferential treatment for renewable jet fuel provides no net benefit to consumers or energy security.

Another commenter requested policy that establishes RIN equivalence between biodiesel production and renewable diesel production to benefit all participants in domestic BBD production.

Response:

EPA did not propose to create any new or “unique” pathways for renewable jet fuel in this rule (the proposed changes to Table 1 to 40 CFR 80.1426 involving renewable jet fuel were simply part of a restructuring of existing approved pathways in Table 1), nor did we propose extending the RFS obligations to producers of petroleum-based jet fuel or removing any of the pre-existing pathways allowing RIN generation for renewable jet fuel. These comments are beyond the scope of this rule. We note that the equivalence value for renewable jet fuel that we are finalizing for this rule is based solely on the estimated renewable content and energy content of jet fuel and does not reflect any preferential treatment for renewable jet fuel over any other renewable fuel. 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.

Comment:

Several commenters stated that renewable jet fuel does not meet the definition of “biomass-based diesel,” and the proposed equivalence value is too high. The commenters added that inflated equivalence values allow RINs to replace actual gallons to meet the volume requirements. Another commenter stated that EPA’s proposed rationale supports an equivalence value for renewable jet fuel of 1.5.

Response:

Based on an updated technical analysis we are finalizing an equivalence value of 1.5 for renewable jet fuel. EPA determined that renewable jet fuel qualified as BBD in 2013.[217] We did not propose to reconsider or otherwise change this determination in this rulemaking, nor did we request comment on the qualification of renewable jet fuel as BBD. EPA provides a respond to comments on the definition of “biodiesel” and “biomass-based diesel” in RTC Section 4.5.

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[217] 78 FR 14190, 14201 (March 5, 2013). EPA clarified that existing pathways listing “renewable diesel” included jet fuel and added jet fuel to these pathways in Table 1 to 40 CFR 80.1426.

Comments related to the qualification of renewable jet fuel as BBD are beyond the scope of this rule.

Comment:

A few commenters discussed that footnote 50 in the proposed rule appears to contain a typographical error and requested that EPA clarify and confirm that the proposal is for an equivalence value of 1.6 for renewable jet fuel rather than 1.5. In addition, one commenter expressed support for the 1.6 value, while another argued that the 1.6 value does not appear to be technically defensible given the energy content of renewable jet fuel.

Relatedly, a commenter stated that EPA must adjust downward the equivalence value for jet fuel to 1.5, based on the values in EPA's memorandum and consistent rounding conventions. The commenter also requested that EPA finalize the revised equivalence value for renewable diesel.

Response:

The footnote referenced by the commenter indicating a proposed equivalence value of 1.5 for renewable jet was an error in the proposed rule. For this final rule, however, we have updated and revised our technical analysis estimating the renewable content and energy content of renewable jet fuel. Based on our revised analysis, we are finalizing a default equivalence value of 1.5 for renewable jet fuel in this action.[218]

Comment:

A few commenters urged EPA to establish minimum threshold energy content for renewable jet fuel, naphtha, and propane, along with renewable diesel, and implement a compliance mechanism to periodically verify the energy content of hydrotreated fuels produced or assign a lower equivalence value for non-compliance.

A commenter discussed that to ensure fair competition between different fuel types, EPA must include minimum heating values for fuels with an equivalence value set in regulation. The commenter suggested specific heating values: 123,800 Btu per gallon for renewable diesel, 119,777 Btu per gallon for renewable jet fuel, 111,520 Btu per gallon for renewable naphtha, and 84,250 Btu per gallon for renewable propane.

Relatedly, a commenter recommended that if renewable diesel producers want to claim a 1.6 equivalence value, they should be required to demonstrate that their fuel meets the threshold energy content of 123,800 Btu per gallon through regular testing using ASTM D240 or a similar test. Similarly, for renewable jet fuel with a higher 1.5 value, the commenter suggested this should only apply to fuels with at least 119,000 Btu per gallon, with the same ongoing compliance testing requirements.

[218] For more detail on our updated technical analysis 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.

A commenter recommended that EPA use the following heating values: 123,800 Btu per gallon for renewable diesel; 119,000 Btu per gallon for renewable jet fuel; 112,600 Btu per gallon for renewable naphtha; and 84,250 Btu per gallon for renewable propane.

Response:

In this final rule we are establishing a default equivalence value for renewable diesel that is consistent with our technical evaluation. Renewable diesel producers may use this equivalence value or, alternatively, submit an application for a higher equivalence value under 40 CFR 80.1415(c) if they believe a higher equivalence value is merited based on the renewable content and energy content of the fuel they produce. Any petitions must include testing results of the energy content of the renewable diesel, as suggested by the commenters. At this time, it is unclear whether regular testing as requested by the commenter 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.

While we are not establishing minimum energy contents for renewable jet fuel or naphtha, based on our technical assessment we expect that the equivalence values we are finalizing in this rule are appropriate for the vast majority of these fuels. Our decision to establish default equivalence values for these fuels that do not require testing for energy content (beyond what is needed to meet industry specifications, such as ASTM standards, for these fuels) reflects a desire not to place additional requirements on renewable fuel producers when such requirements are not necessary to ensure the integrity of the RFS program.

Comment:

Several commenters made recommendations regarding the use of renewable hydrogen in the production process and other process improvements. A commenter recommended that EPA explore how the use of renewable hydrogen used in hydrotreating or the production of a biointermediate could be incorporated into the RFS program for the purpose of an equivalence value adjustment. The commenter suggested implementing a system where a fuel produced with renewable hydrogen could generate two types of RINs on a single type of fuel.

A commenter stated that while they do not oppose providing some incentive for the use of renewable hydrogen, RIN generation must be limited to using renewable biomass as defined in the statute. The commenter argued that renewable hydrogen would not constitute “biomass-based diesel” under the statute and would more appropriately generate a D3 or D5 RIN. The commenter also suggested that a similar assessment be done for using renewable methanol or ethanol in the biodiesel production process.

A commenter provided a detailed overview of how a pathway for renewable hydrogen used in the hydrotreating process could generate D3 or D5 RINs when produced from RNG. The commenter stated that the pathway may require revisions to RIN separation provisions 40 CFR 80.125(d)(1), (d)(2), and (e)(3). The commenter argued that approval of these pathways would contribute significantly to the cellulosic biofuel mandate and could quickly inject a significant amount of D3 RINs into the market while supporting the goals of the RFS program, EPA's priorities with respect to new pathways, and the Administration's energy policy goals.

Response:

EPA did not propose any new pathways to allow renewable fuel producers to generate RINs for renewable hydrogen used in renewable diesel production. Nor did the Agency propose new pathways to allow RIN generation for using renewable methanol or ethanol in the biodiesel production process. There are many technical, legal, and policy issues that would need to be resolved before such a renewable hydrogen used in renewable diesel production pathway could theoretically be approved. These issues include but are not limited to: the category of renewable fuel for which renewable hydrogen qualifies, the lifecycle GHG emissions for renewable hydrogen used in renewable diesel production, appropriate crediting for hydrogen that is incorporated into transportation fuel (versus hydrogen that is used in the processing of renewable diesel but does not end up in transportation fuel), and the portion of renewable hydrogen that is derived from renewable biomass. We reiterate that EPA has not addressed these issues or a renewable hydrogen pathway in this rulemaking.

Comment:

A commenter argued that EPA's move to untether equivalence values from volumes is illegal and could undermine the integrity of the RFS program. The commenter expressed concern that if equivalence values become arbitrary, they could create regulatory uncertainty that undermines capital formation and limits industry growth. Another commenter urged EPA to recognize that even incremental changes to the RFS program, especially those affecting RIN generation and RVO compliance, can impact investor decisions. The commenter requested that EPA avoid structural changes that risk undermining the biodiesel and renewable diesel sector.

Response:

EPA is not making any structural changes to our approach to establishing equivalence values for qualifying renewable fuels in this final rule. Since 2010, equivalence values in the RFS program have been determined based on the energy content and the renewable content of the renewable fuel. The equivalence values we are finalizing for renewable diesel, jet fuel, and naphtha in this final rule are consistent with EPA's longstanding approach to determining equivalence values in the RFS program. We share the commenter's concerns that deviating from this approach, especially without notice and opportunity for public comment, could be arbitrary and cause significant uncertainty in the RFS program.

Comment:

A commenter argued that EPA's proposal to decrease the equivalence values for renewable diesel, jet fuel, and naphtha exacerbates the need for more physical gallons, which will increase demand for feedstocks and drive up program costs.

Response:

For any given renewable fuel volume requirement, decreasing the equivalence values for the available qualifying renewable fuels would result in a greater volume of these fuels being needed to meet the volume requirement. EPA has taken this into account in this final rule by considering the anticipated equivalence values for the available qualifying renewable fuels when establishing the volume requirements for each year. Specifically, when calculating the appropriate BBD, advanced biofuel, and total renewable fuel volume requirements for 2026 and 2027, we have projected that renewable diesel produced in 2026 will generate 1.7 RINs per gallon (based on the applicable equivalence value in 2026) and 1.6 RINs per gallon in 2027. We are finalizing a default equivalence value of 1.5 for renewable diesel in 2027 based on our calculated estimate of the heating value for renewable diesel. However, we expect that, based on the information submitted by current renewable diesel producers at the time of their initial facility registration, that the majority of renewable diesel produced in 2027 will have requested an equivalence value of 1.6 RINs per gallon through the application process in 40 CFR 80.1415(c).[219] The renewable fuel volumes we are finalizing in this rule for 2027 are calculated assuming renewable diesel generates 1.6 RINs per gallon on average in 2027 to avoid the need for even greater volumes of renewable fuel with the associated high costs described by the commenter.

Comment:

A commenter stated renewable propane and liquefied petroleum gas (LPG) were not addressed in the proposed rule and suggested that EPA define renewable LPG similar to the proposed renewable naphtha definition and establish a baseline equivalence value of 1.1 RINs per gallon. Relatedly, another commenter estimated that the equivalence value for renewable propane should be revised from 1.1 to 1.0 RINs per gallon based on their calculations.

Response:

We did not propose equivalence values for renewable propane and LPG. We do not have sufficient information to establish default equivalence values for these fuels at this time. We recognize that these fuels likely also contain some quantity of fossil-based hydrogen when produced from vegetable oils or fats, oils, and greases using a hydrotreating process. We may consider establishing default equivalence values for these fuels in a future action.

[219] Most renewable diesel producers currently generate 1.7 RINs per gallon of renewable diesel. To qualify for an equivalence value of 1.7, renewable diesel producers must produce fuel with an energy content greater than 123,500 BTU/gallon (40 CFR 80.1415(b)(4)). Renewable diesel producers that demonstrate an energy content above 123,500 BTU/gallon would be eligible to apply for an equivalence value of 1.6 in 2027 or any future year.

11.2 RIN-Related Provisions

11.2.1 RIN Generation and Assignment

Comment:

Several commenters expressed concern about EPA's proposed limitation on the timeframe allowed for RINs for RNG and renewable fuels that are gaseous at standard temperature and pressure must be generated no later than five business days after all applicable requirements for RIN generation have been met. The commenters stated that this timeframe does not allow sufficient space to validate data required by the regulations, including data received from the pipeline owner or utility. The commenters requested that EPA extend this window to monthly, with language similar to 40 CFR 80.1451(f)(4) and 40 CFR 80.140(b), to allow producers ample time to reconcile necessary data and to ensure data necessary for RIN generation. On the other hand, another commenter expressed support for this requirement, and suggested that EPA update EMTS to accommodate this change.

Response:

The requirement at 80.1426(f)(18)(ii)(A) specifying the five-business day window is specific to submitting information into EMTS for RIN generation after the RIN generation event. In other words, once an RNG producer meets the requirements under 40 CFR 80.125(b), 80.130(b) and 80.1426(f), that producer then has five days to assign RINs to that batch and enter this information into EMTS. This is consistent with requirements going back to 2010 as described in 40 CFR 80.1452(b).

To provide additional clarification, we provided an example in Preamble Section VIII.B.1 and added clarifying text to 40 CFR 80.1426(f)(18).

Comment:

Several commenters expressed confusion on the purpose of some proposed changes, noting that under the proposed new provision, RINs are to be generated at "the point of production or point of sale" for domestic renewable fuel producers. The commenters stated that EPA has long provided producers flexibility as to when to generate RINs per "batch" of fuel, which can depend on the type of production at the facility (*e.g.*, batch or continuous). Additionally, the commenters noted that the phrases "point of production or point of sale" are unclear in this context, as they are typically used to refer to a location, and thus do not appear to provide any clarification as to when RINs are to be generated or assigned.

Response:

This addition to the regulations only codifies existing business practices first described in the RFS2 Rule and we are still maintaining these flexibilities around how RINs are assigned to batches. Our intent is to improve consistency and provide clarity on RIN generation timing only in response to recent industry questions. “Point of production” or “point of sale” has in practice been used since 2010 and we will continue to use the mechanism for assigning RINs to volume.

Comment:

One commenter requested clarification on the meaning of the “point of importation,” which can vary depending on the mode of transportation that the imported fuel is undergoing as well as considerations involving the denaturing of imported ethanol.

Response:

Our intent for using the term “point of importation” was specific to RIN-generating *renewable fuel* producers and encompasses all applicable requirements for importing renewable fuel. For example, ethanol covered by the definition of renewable fuel must be denatured. The term “point of importation” does not apply for RNG and renewable fuels that are gaseous at STP, which is described at 40 CFR 1426(f)(18)(ii)(A). However, to avoid confusion we are updating this to read “upon importation,” which we believe captures the same intent without adding additional regulatory text.

Comment:

Two commenters stated that it is not clear how the proposed language for generating RINs at the point of importation interacts with the requirements of having an independent third-party verify the volumes. The commenter recommended that EPA adopt the same RIN generation timing that it proposes for domestic RNG (*i.e.*, require the generation/assignment of RINs within 5 business days of meeting all applicable requirements).

Commenters stated the point of importation requirement is not clear in how this requirement interacts with independent third-party verification. Under the current regulations, the generation of RINs for the import of foreign RIN-less RNG is tied to the completion of an independent third-party volume verification report under 40 CFR 80.160(h)(2) which is due within 30 days of importation. The commenters stated that it is not clear how the proposed language for generating RINs at the point of importation interacts with the requirements of having an independent third-party verify the volumes.

Response:

We are clarifying that the RIN generation event for RNG RINs is when all applicable requirements are met under 80.125(b), 80.130(b), and 80.1426(f). Once all required information under these sections is available, the RIN generator may proceed with generating RINs. Domestic importers and foreign RIN-less RNG producers should continue to meet the requirements described in 80.160(h)(2) to ensure accurate reporting and for registration and recordkeeping purposes, but not necessarily before the RIN generation event.

Comment:

Several commenters stated that while they support clarifying RIN assignment provisions for RNG, they do not believe EPA's proposed revisions provide such clarity. The commenters urged EPA to make clear that it is not changing the long-standing pipeline injection and withdrawal methods of the biogas regulatory provisions and suggested alternative regulatory language to address the issues with RNG RIN assignment.

Response:

Commenters are correct that EPA is not changing the pipeline injection and withdrawal methods of the biogas regulatory provisions. We have reviewed the regulatory text revisions suggested by commenters and incorporated their feedback into the final RIN generation and assignment provisions, including at 40 CFR 80.125(c), 80.1426(f), and 80.1428.

In the regulations, we have also clarified that any party purchasing RINs assigned to a volume of RNG is deemed to also be acquiring a corresponding volume of RNG for purposes of 40 CFR part 80 (*i.e.*, the RFS program). In this way we are establishing consistent treatment of assigned RINs between RNG and other renewable fuels and how the assigned RINs with a corresponding volume are transferred to downstream parties. This balances the need to ensure assigned RINs remain associated with a quantity of RNG until they are separated but does not require burdensome tracking or direct RNG transfers.

Comment:

One commenter requested adding new regulatory text specific to RNG assignment and separation that crossed between 40 CFR 80.125, 80.1426, and 80.1428. This included adding that RINs for RNG are assigned the same time the assigned RIN is generated, defining that RNG "is an assigned RIN" until RIN separation and clarifying RNG RIN transfer. Additionally, the commenter recommended modifying prohibited acts to better align with existing business practices regarding how RNG RINs are transferred between parties.

Response:

We have modified the regulatory text in 40 CFR 80.125(c) to clarify that assigned RNG RINs are transferred with a corresponding volume of RNG to the transferee. We believe that by changing 40 CFR 80.125(c), the recommended change to 40 CFR 80.1428(a)(2) no longer applies. Additionally, we have modified 40 CFR 80.1460 similarly to how the commenter suggested. In conjunction with 40 CFR 80.125(c), by transferring title of the assigned RIN with a K code of 3, the party is deemed to have transferred a volume of RNG.

We do not agree with the commenter that 40 CFR 80.1426(e) should be changed, because of the changes made to 40 CFR 80.125(c).

11.2.2 Renewable Fuel Used for Process Heat or Electricity Generation

Comment:

Some commenters expressed support for EPA's proposal to ensure that renewable fuels not used as transportation fuels are ineligible for RIN generation. They agreed with EPA that the CAA and RFS regulations clearly "prohibit RIN generation for fuel that does not replace or reduce the quantity of fossil fuel present in a transportation fuel, heating oil, or jet fuel."

Response:

We thank the commenters for their support.

Comment:

Several commenters expressed concerns about EPA's proposed changes to the definition of "heating oil" that would exclude pure biodiesel (B100) or neat biodiesel (B99) used for process heat or power generation from qualifying as heating oil under the RFS program and requested that EPA remove the prohibition of B99 and B100 from the proposed definition of heating oil. Commenters also noted that differentiating between "pure biodiesel (B100)" and "neat biodiesel (B99)" is unnecessary because B100 is referred to as neat in the industry, and EPA already defines "neat renewable fuel" as unblended with petroleum fuel. A few commenters argued that EPA's rationale that B99 and B100 are not "commonly or commercially known as heating oil" is inaccurate because they are being marketed as a viable heating oil, and this would create confusion for biodiesel producers that sell B100 and B99 into the heating oil market or that sell to marketers or terminals. One commenter stated that they are located in Hawaii where it does not get cold enough for gelling to occur, and asked for an exception. One commenter noted that they expect to generate an ASTM Committee D02 ballot later in the year to approve up to B50 blends for use as heating oil under ASTM D396, and that they have worked collaboratively with equipment manufacturers to certify their latest equipment offerings for use with up to B100. Another commenter argued that EPA has expressly stated that blends of biodiesel above B80 qualify as described in the RFS2 Rule and EPA's response to comments for that rule.

Response:

EPA has considered commenters' concerns regarding its clarification on levels of biodiesel that qualify as heating oil when used for process heat or electricity. Rather than revising the definition of heating oil to exclude B99 and B100, EPA has determined that its objective of ensuring that RINs are only generated for valid purposes under the RFS program is better achieved by prohibiting RIN generation for any renewable fuel used to generate electricity or process heat as that does not reduce or replace fossil fuels used for transportation fuel, heating oil, or jet fuel.

EPA does not intend that this final rule prohibit biodiesel producers from selling their biodiesel into the heating oil market or to marketers and terminals, because biodiesel can be blended into petroleum products for use as heating oil. Producers that sell their biodiesel into the heating oil market without indicating the ultimate end user will not be in violation so long as all PTD, recordkeeping, and registration requirements are met.

EPA does not have the authority to exempt Hawaii from this specific requirement. The commenter may still produce and sell its biodiesel for process heat or generating electricity, but RINs may not be generated on biodiesel or any other renewable fuel used for such purposes because those purposes are outside the scope of the RFS program.

Comment:

A commenter stated that the addition of the term "renewable fuel oil" and the proposed change to the heating oil definition raises unnecessary confusion. The commenter pointed out that the proposed change contradicts EPA's response to comments in the 2013 Heating Oil Rule, which confirmed 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. Another commenter suggested that EPA confirm, as it did in 2010 and 2013, that "biodiesel (and renewable diesel) can be designated and sold for use into the heating oil market at any blend level (including 'pure biodiesel' and 'neat biodiesel') and without any additional burdensome tracking requirements, particularly any requirement to obtain affidavits from end users and separate product transfer document requirements that could conflict with other requirements and create confusion in the marketplace."

Response:

EPA addresses comments on the definition of "renewable fuel oil" and its interaction with the "heating oil" definition in RTC Section 11.5.1.

EPA confirms that it is not adding any additional tracking requirements for heating oil under this rulemaking, including obtaining affidavits from end users. Biodiesel and renewable diesel may still be designated and sold for use in or as heating oil. If a RIN generator—usually the renewable fuel producer—has reason to know that the renewable fuel will be used for process heat or electricity generation, the RIN generator may not generate RINs on that fuel and must retire any RINs already generated on the batch.

Comment:

A commenter also expressed concern about the language that prohibits generating RINs on neat biodiesel used for electricity generation. The commenter said that anything that reduces Hawaii's production of its own energy risks causing severe power grid outages in the future, and asked EPA to allow neat biodiesel used for electricity generation to qualify for RIN generation, at least in Hawaii. The commenter suggested that EPA word the requirement similarly to the IRS 45Z credit. The commenter said that the language for the 45Z credit states that renewable fuels must be able to be used in transportation, but don't need to be used in transportation to qualify. Another commenter urged EPA to reject the disallowance of RIN generation from these non-transportation sources and instead extend RIN generation to renewable fuels used to generate electricity for data centers, hospitals, 911 call centers, and other mission critical facilities.

Another commenter said that for 15 years, EPA has correctly allowed RIN generation for heating oil used in both residential space heating and water heating, consistent with Congressional intent. The commenter said that the proposed definition changes appear unduly restrictive, which would be a significant and unexplained departure from established policy that must be addressed. The commenter said that some of the claimed "technical corrections" could be read as making significant changes to the current regulations without explanation and in violation of the notice and comment requirements of the CAA.

Response:

EPA does not have the authority to promulgate regulations to mirror the 45Z credit. EPA's statutory authority to promulgate the RFS regulations is the CAA, which states that the renewable fuel must replace or reduce the quantity of fossil fuel present in transportation fuel, home heating oil, or jet fuel. Because process heat and electricity generation are not among the named renewable fuel uses in the CAA, RINs may not be generated on renewable fuel used as such, which includes renewable fuel used to generate electricity for data centers. Further, EPA does not have the authority to grant exemptions to generate RINs on renewable fuel used for anything other than transportation fuel, jet fuel, or home heating oil.

However, as explained in Preamble Section VIII.B.2.c, the prohibition on RIN generation does not apply to incidental volumes of renewable fuel used for electricity generation in emergency backup generators for mission critical functions during power outages. We are not imposing additional documentation burdens on producers of such fuel in this final rule. Therefore, those producers are not expected to determine whether their renewable fuel is ultimately used in backup diesel powered generators. This, however, does not apply to data centers.

A commenter asserted that the miscellaneous technical corrections and clarifications in the proposed rule may violate the CAA's notice and comment requirements. Specifically, the commenter argued that replacing the term "heating oil" with "renewable fuel oil" in Table 1 to 40 CFR 80.1426 and the definitions of cellulosic diesel and co-processed cellulosic diesel under 40 CFR 80.2 are substantive changes beyond technical corrections or clarifications. EPA has considered the comment and, as explained further in RTC Section 11.5.1, is not replacing "heating oil" with "renewable fuel oil" in the regulations identified by the commenter.

Comment:

Two commenters questioned if the purpose of EPA's proposed rule is to prevent biodiesel producers from generating RINs on biodiesel used at their facilities. The commenters stated that they do not think the RFS regulations allow biodiesel producers to generate RINs for biodiesel used at their facilities, and that if it is EPA's intention to clarify this, it should say so explicitly.

Response:

EPA confirms that a renewable fuel producer may not generate RINs on renewable fuel for use as process heat or electricity generation at its facility. RINs generated on renewable fuel used at a production facility must be retired. This does not add any burdensome tracking requirements for the producer because they themselves are the end user. Additionally, renewable fuel used by the producer will not have a PTD because ownership is not being transferred. RINs may not be generated for any fuel that is not designated on a PTD for use as transportation fuel, heating oil, or jet fuel.[220]

[220] 40 CFR 80.1426(a)(1)(iv).

11.3 Percentage Standard Equations

Comment:

Several commenters expressed support for EPA's proposal to express BBD volume requirements in RINs rather than physical gallons. One of the commenters stated that EPA's past practice of expressing BBD requirements using physical gallons (when all other renewable fuel requirements are expressed using RINs) had often created confusion among regulated entities regarding the correct way to interpret BBD volume and RVO percentage standards.

Response:

We thank the commenters for their support.

Comment:

Several commenters opposed expressing the BBD volume requirement in RINs and stated that the CAA specifically calls for the BBD category to be stated in gallons of biodiesel. A few commenters disagreed with EPA's assertion that there has been "confusion among stakeholders regarding how to interpret the BBD volume requirement," arguing that the formula for determining how many RINs are needed for compliance is clear, and changing the requirement would not necessarily ensure the volumes are met, based on equivalence values. Other commenters argued that EPA's proposal to move away from physical gallons to RINs was only necessitated by its change in the treatment of imports.

Response:

We disagree with commenters that the CAA specifically calls for the BBD volume requirement to be expressed in physical gallons. As further discussed in Preamble Section VIII.C, the applicable volumes of all four categories of renewable fuel specified by Congress in CAA section 211(o)(2)(B)(i) are all in units of "billions of gallons"; nowhere does the statute specify that the units of the BBD volume requirements are to be treated differently than the other renewable fuel volume requirements. And, critically, nowhere does the statute provide that any of the volume requirements be interpreted specifically as physical gallons of biodiesel (as opposed to RIN-gallons). While EPA previously established the BBD volume requirement in physical gallons, there is nothing in the statute that prevents EPA from now expressing the BBD volume requirement in RINs, consistent with its long-standing approach to the other fuel volumes. EPA explains its reasons for doing so in Preamble Section VIII.C and further elaborates on those reasons here. EPA notes that this change does not implicate reliance interests because there is no practical effect on regulated parties.

Contrary to commenters' assertions, expressing the BBD volume requirement in gallons but then requiring compliance through the use of RINs has in fact lead to confusion. To the general public, it is not inherently obvious why the BBD volume requirement was previously established in units different from the other three renewable fuel categories or why there was a 1.5 or 1.6 multiplier in the BBD percentage standard equation to translate the BBD volume requirement into a percentage standard. For example, due to the nested nature of the RFS standards, the 3.35-billion-gallon BBD volume requirement for 2025 was projected to contribute approximately 5.4 billion RINs towards meeting the advanced biofuel and total renewable fuel volume requirements for 2025. Further, on EPA's RFS compliance data website, the projected volume obligation for BBD is provided in physical gallons (since this is the volume used to establish the percentage standard), but all the compliance data is expressed in RINs.[221] This leads to the natural question of why there is such a large discrepancy between the numerical value of the BBD volume requirement and the number of RINs used to comply with the BBD standard.[222] Expressing the BBD volume requirement in RINs eliminates this source of confusion.

Furthermore, as discussed in the Set 1 Rule, "The average [equivalence value] of BBD appears to have grown over time without stabilizing. This trend has continued and is consistent with the growth in facilities producing renewable diesel."[223] In that action, we increased the BBD multiplier from 1.5 to 1.6 based on the average equivalence value of BBD at the time. However, rather than continuing to evaluate the average equivalence value of BBD in each RFS volume standard rule and, if necessary, correspondingly adjust the BBD multiplier in the BBD percentage standard equation, it is more straightforward to project the availability of BBD RINs and simply express the BBD volume requirement in RINs like all the other renewable fuel categories and eliminate the need to have a BBD multiplier altogether.

Finally, while the proposed import RIN reduction provisions would have impacted the number of BBD RINs generated, it was not the primary reason why we proposed to change how we express the BBD volume requirement. As described in the Set 2 proposal, "we are proposing to make 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."[224] While the proposed import RIN reduction provisions would have had an impact on how we determine the volume requirements, our decision to change how we express the BBD volume requirement was made for the reasons described in Preamble Section VIII.C and independently of the proposed import RIN reduction provisions.

Comment:

Several commenters argued that by changing the formula from gallons to RINs, it becomes entirely unclear what the "applicable volume" is that EPA is setting under CAA section 211(o)(2)(B)(ii). The commenters believed this change favors renewable diesel, which has a higher RIN value that can reduce the actual volumes needed. The commenter concluded that there would now be a greater incentive for obligated parties to purchase renewable diesel over biodiesel to reduce their obligation.

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[221] Table 2: Obligated Party RVOs by Year. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and.

[222] See, *e.g.*, BBD compliance data for 2023, which shows a projected volume obligation of 2.82 billion but the reported 2023 volume obligation was 4.66 billion.

[223] 88 FR 44546 (July 12, 2023).

[224] 90 FR 25825 (June 17, 2025).

Response:

We disagree with commenters that the change to the BBD volume requirement favors renewable diesel over biodiesel. First, as discussed Preamble Section VIII.A and RTC Section 11.1, EPA is reducing the equivalence value for renewable diesel from 1.7 to 1.5, giving it parity with biodiesel. Thus, there is no inherent advantage for renewable diesel over biodiesel since both fuels will generate the same number of RINs per gallon. Second, as EPA has discussed numerous times, the BBD volume requirement is not a binding standard that drives BBD demand.[225] Rather, it is largely the advanced biofuel standard, and to a lesser extent the total renewable fuel standard —which have always been specified in gallon-RINs—that drive biodiesel and renewable diesel demand.

Changing the BBD volume requirement from being specified in physical gallons to RINs is intended to the reduce confusion and provide consistency in how EPA specifies the applicable volumes for all renewable fuel categories; it is not expected or intended to have any material impact on the demand for biodiesel and renewable diesel or the actual BBD percentage standard. As discussed in Preamble Section VIII.C, if EPA were to still specify the BBD volume requirements for 2026 and 2027 in gallons, we would have first calculated the BBD volume requirement in RINs and then divided by 1.6 (the BBD multiplier) to convert to physical gallons. We would then have multiplied this volume in physical gallons by 1.6 in the BBD percentage standard equation (*i.e.*, essentially undoing the original conversion from RINs to physical gallons) to determine the BBD percentage standard. Thus, even if we were to still specify the BBD volume requirements in physical gallons for 2026 and 2027, we would ultimately end up with the same percentage standards—which are the requirements that obligated parties actually to comply with—that we are establishing in this action using BBD volume requirements specified in RINs.

Comment:

One commenter supported the proposed removal of GS_i, DS_i, RGS_i, and RDS_i from the percentage standard equations. However, the commenter suggested that use the term “blended” is not necessary in the definitions of RG_i and RD_i.

[225] See, *e.g.*, “Further, we note that we project that the production and use of BBD in 2023–2025 will primarily be driven by the advanced biofuel and total renewable fuel volume requirements. Establishing lower BBD volume requirements would not be expected to impact the total production and use of BBD.” Set 1 Rule RTC Section 6.1.2. See also, *e.g.*, “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 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.” 90 FR 25825 (June 17, 2025).

Response:

We thank the commenter for their support. We agree that the term “blended” is not necessary in the definitions of RG_i and RD_i and have removed it from the final definitions.

11.4 Renewable Fuel Pathways

11.4.1 Table 1 Pathways that Include "Any" Production Process

Comment:

A commenter opposes limiting Row K of Table 1 to 40 CFR 80.1426 to only those dry mill fermentation processes that use fiber while sourcing all process energy from biomass. The commenter states that several proven technologies already achieve lower carbon intensity scores while utilizing fossil-derived process energy. They argue that restricting pathway eligibility to narrow production configurations would stifle innovation, undermine past investments, and contradict the RFS's broader goal of transitioning from conventional to advanced fuels.

Response:

We believe the commenter misunderstood this part of the proposed rule. As discussed in Section X.D.1.A of the Set 2 proposal, for ethanol produced from corn and grain sorghum kernel fiber, we proposed to revise the production process column of Row K to include, "Dry mill process that converts corn or grain sorghum kernel fiber to ethanol and uses natural gas, biogas, or crop residue for all thermal process energy." The commenter opposes limiting this pathway to processes that source all process energy from biomass, but the proposed pathway definition also includes dry mill process that use natural gas for process energy. We note that based on industry survey data, the inclusion of these process energy sources covers practically all dry mill facilities operating in the United States.[226] For these reasons, we believe the commenter's opposition to the proposed changes are based on a misunderstanding, and we are not modifying the proposed revisions to Row K in response to this comment.

Comment:

A commenter recommends that revisions to Row M should not limit the eligibility of dairy-derived cellulosic biofuels produced using natural gas, biogas, or biomass as process energy sources.

Response:

We believe the commenter misunderstood this part of the Set 2 proposal. As discussed in Section X.D.1.B of the Set 2 proposal, we proposed changes to Row M to define the qualifying process technologies more precisely to ensure that fuels produced through Row M satisfy the statutory criteria to qualify as renewable fuel (and thus to generate RINs). Row M has never explicitly included "dairy-derived" biofuels (*i.e.*, the feedstocks listed in Row M do not include dairy manure or other feedstocks commonly sourced from dairies), which makes this part of the

[226] Lee, Uisung, Hoyoung Kwon, May Wu, and Michael Wang. "Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005–2019: Implications for Greenhouse Gas Emission Reductions." *Biofuels Bioproducts and Biorefining* 15, no. 5 (May 4, 2021): 1318–31. https://doi.org/10.1002/bbb.2225. See Figure 3.

comment unclear to us. For these reasons, we are not modifying the proposed revisions to Row M in response to this comment.

Comment:

A commenter encourages EPA to reconsider the proposed requirement mandating that eligible facilities must be net exporters of electricity to the grid and exclusively use lignin or biogenic residues for all thermal and process energy needs. The commenter says these restrictions are unnecessary.

Response:

Based on this comment and further review of the evaluations EPA previously conducted for the cellulosic biofuel pathways in Rows K, L and M of Table 1, we are finalizing modified production process conditions relative to what we proposed. As requested by the commenter, the modified conditions do not require net export of electricity to the grid. However, the conditions continue to include exclusive use of lignin or other components derived from the renewable biomass feedstock to provide thermal and electrical process energy. The commenter has not provided data or specific technical reasons to exclude these conditions on the source of thermal and electrical process energy. Furthermore, as discussed in Preamble Section X.D.1, based on the LCA work completed in support of these pathways, we continue to believe these requirements are necessary to ensure that fuel produced under this pathway meets the 60% threshold. Fuel producers who do not meet these conditions but believe the fuel they produce satisfied the statutory criteria may submit a petition pursuant to 40 CFR 80.1416 requesting EPA's evaluation of their fuel pathway.

Comment:

A commenter opposes the proposed revisions to the descriptions of the pathways for CNG/LNG in Table 1 of 40 CFR 80.1426, stating they are unnecessary. The commenter notes that the pathways for RNG have been in place since at least 2014, the industry has long relied on these pathways as written, and EPA approves all facilities through the registration process to confirm compliance with these pathways. The commenter argues there was no reason to revise the pathways now.

Response:

We disagree that the proposed revisions are unnecessary. As discussed in Section X.D.1 of the Set 2 proposal, the reason for the proposed changes to Rows Q and T is to define the qualifying process technologies more precisely to ensure that fuels produced through Rows Q and T satisfy the statutory criteria to qualify as renewable fuel (and thus to generate RINs). Based on our experience implementing these pathways under the RFS program since 2014, we believe these clarifications will help to ensure the integrity of these pathways going forward. As a general matter, we believe this is a sufficient and necessary reason for clarifying the language in Rows Q and T. We also see no adverse impacts for RNG producers or other stakeholders associated with these regulatory clarifications as finalized. To our knowledge, all the producers currently registered to generate RINs for renewable CNG/LNG use production processes that are consistent with the changes to Rows Q and T. Fuel producers seeking a new pathway for renewable CNG/LNG using a process that is not consistent with the changes to Rows Q and T can submit a petition pursuant to 40 CFR 80.1416 requesting EPA's evaluation of the new pathway, and the evaluated pathway may qualify the same RIN D codes listed in Rows Q or T.

Comment:

A commenter challenged EPA's assertion that the analyses the Agency undertook that form the basis for the Rows Q and T pathways assumed the renewable CNG would be transported via pipeline and that the renewable LNG would be used as a transportation fuel within a relatively short time after it was produced. The commenter noted that EPA stated it assumes that renewable LNG produced in North America would be used relatively soon after production, and for these reasons, EPA claimed it was "clarifying" that the production process requirements for Rows Q and T are limited to processes that occur in North America. While the commenter did not disagree that most RNG used under the RFS program is produced in North America, they argued there was no indication that any additional emissions from storing LNG or transporting CNG would result in significant emissions that would impact the findings that the lifecycle GHG emissions reductions are greater than the required 50% or 60% under the statute. Moreover, the commenter pointed out that EPA does not restrict any other pathway based on production in North America.

Response:

Based on our consideration of this comment and further review of EPA's prior evaluations of the renewable CNG and LNG pathways, we are modifying the proposed condition that the commenter disagrees with. Rather than making the approved pathways conditional upon production in North America, we are instead excluding transport of RNG, CNG, or LNG by ocean-going vessel from the approved pathways. As described in the Set 2 proposal, long-duration transport by ocean-going vessel may be associated with relatively large emissions that have the potential to be dispositive in terms of meeting the statutory emissions reduction criteria to qualify for cellulosic or advanced RINs. As discussed in the Set 2 proposal, the LNG boil-off rate is estimated at 0.1–0.15% per each day associated with transportation and distribution, including any combination of storage at the LNG production plant, transport aboard ocean-going vessels, and storage at bulk terminals, all of which increase pathway emissions. We estimate that transportation and distribution via ocean-going vessels exceeding 24 days would potentially increase the lifecycle emissions enough to change the finding that renewable LNG satisfies the 60% reduction threshold to qualify for D3 RINs.[227] Accordingly, it is appropriate to condition the pathway on this basis, as the resulting increased emissions associated with transport by ocean-going vessels are due to the increased duration of these stages in the pathway. Relative to the proposed condition that renewable CNG/LNG be produced in North America, we believe the exclusion of ocean-going vessel transport more directly addresses the concerns discussed in the Set 2 proposal. We further discuss this issue in Preamble Section VIII.D.1.

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[227] The R&D GREET model's assumptions regarding liquefied natural gas boil-off were applied to estimate daily emissions for typical ocean-going transport and distribution durations.

Comment:

Two commenters stated that, for pathways Q and T, in addition to specifying that CNG/LNG production from treated biogas qualifies, EPA should also specify CNG/LNG produced from RNG also qualifies. One of the commenters also believes that CNG/LNG produced from biogas qualifies. They are concerned that the proposed revisions list CNG/LNG produced from treated biogas, to the exclusion of CNG/LNG produced from RNG and biogas. They argue this creates inconsistencies in the regulations and they believe it was not EPA's intent to exclude CNG/LNG produced from RNG or biogas.

Response:

We are modifying the proposed amendments to Rows Q and T in response to this comment. Specifically, the conditions we are finalizing for Rows Q and T do not reference treated biogas to the exclusion of biogas and RNG. We further discuss this issue in Preamble Section VIII.D.1.

Comment:

A commenter opposes adding language to 40 CFR 80.1426(f)(1)(vii) that appears to impose new limitations on pathways not indicated when EPA approved the pathways. This language would provide: "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 GHG reduction requirement." The commenter says EPA's lifecycle analysis for pathways is often not entirely clear and that EPA seems to be identifying new requirements for CNG/LNG that are not explained or adequately justified. The commenter asserts that merely referencing the lifecycle analysis does not explain why the changes are necessary and that this is particularly true for cellulosic biofuels that have significantly greater GHG emission reductions than required (*e.g.*, well greater than 60% reductions). The commenter opposes the changes because EPA provides insufficient information to understand its concerns.

Response:

We disagree that EPA has provided insufficient information to understand its concerns. The concern that EPA is addressing with the proposed language at 40 CFR 80.1426(f)(1)(vii) is discussed in Section X.D.1.a and b of the Set 2 proposal. The overall concern addressed is that over the life of the RFS program, many fuel production processes have been developed that vary from those assumed in the original assessments underlying the pathways listed in Table 1. Given the possibility that some fuel production processes fitting the descriptions in Table 1 might not actually meet the corresponding statutory GHG reduction requirement, we believe it is inappropriate to continue allowing "any" production process under certain Table 1 pathways. To address these concerns, we proposed two remedies: (1) Revising several rows in Table 1 to more precisely describe the qualifying production process technologies, and (2) Adding the language at 40 CFR 80.1426(f)(1)(vii) quoted by the commenter. The new language in 40 CFR 80.1426(f)(1)(vii) does not impose any additional requirements or limitations beyond the changes EPA is making to Table 1, which reflect the pathways the Agency evaluated when it determined that the pathways satisfy the applicable GHG reduction requirement. EPA has explained why the changes to Table 1 are necessary to ensure consistency with the statutory requirements in Preamble Section VIII.D. The commenter does not raise specific problems or data to support their opposition to these regulatory clarifications. Thus, we are finalizing the language at 40 CFR 80.1426(f)(1)(vii) as proposed.

Comment:

A commenter discussed EPA's proposal to narrowly define the fuel production process for Pathway L and stated that the revisions would jeopardize the company's investment in a new biorefinery. The commenter suggested several alternatives to what EPA proposed: (1) Do not adopt the proposed changes to Row L; (2) Include a process description in Row L that is wide enough that it would include other qualifying processes such as thermo-catalytic deoxygenation and upgrading; (3) Allow parties that have already received communication from EPA that their fuel qualified under pathway L to continue to use pathway L as it was written at the time that EPA issued such communication; (4) Delay the effective date of the proposed change to pathway L until no sooner than January 1, 2028, to allow parties that have already received communication from EPA that they would previously qualify for one of the current pathways time to register or have EPA act on any facility-specific pathway petitions; or (5) If EPA finalizes the changes as proposed with an accelerated effective date, EPA should commit to expedite the commenter's facility-specific pathway petition and approve it prior to the effective date of the narrowing of the pathways.

Response:

We appreciate this comment and understand the commenter's concerns. We address each of the commenter's proposed alternatives below.

Commenter's alternative 1 is to not finalize the proposed changes to Row L. As discussed in Preamble Section VIII.D, we are finalizing changes to specific rows in Table 1, including Row L, to ensure that approved pathways under the RFS program satisfy the statutory criteria, including the lifecycle emissions reduction criteria for cellulosic biofuel in CAA section 211(o)(1)(D).

Commenter's alternative 2 is to finalize a process description in Row L that is wide enough that it would include other qualifying processes such as thermo-catalytic deoxygenation and upgrading. As discussed in the Preamble Section VIII.D.1.b, we are finalizing a broader set of process technologies in Row L than proposed. We do not have enough information on the commenter's suggested process of "thermo-catalytic deoxygenation and upgrading" to determine whether it could potentially fit under the "biochemical conversion and upgrading" process that we are adding to Row L. However, this certainly is a possibility, provided all the conditions are satisfied (*e.g.*, lignin, char, coke or syngas derived from the renewable biomass feedstock provides 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)). We recommend that the commenter review the Row L process technologies discussed in Preamble Section VIII.D.1.b to determine if their process aligns with the production process technology categories evaluated by EPA. As discussed in Preamble Section VIII.D.1.i, renewable fuel producers, including this commenter, seeking to determine if their fuel fits within the bounds of a pathway listed in Table 1 can contact EPA through the pathway screening tool for clarification.[228] 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.

Commenter's alternative 3 is to allow parties that have already received official communication from EPA that their fuel qualified under Row L to continue to use Row L as it was written at the time that EPA issued such communication. We do not believe this alternative would be consistent with the provisions for RIN generation in 40 CFR 80.1426(f) requiring the use of an "approved pathway" as defined in 40 CFR 80.2.[229] It would not be appropriate to allow a party to generate RINs under a pathway that does not meet this definition. In addition to being inconsistent with the longstanding regulations, it would set a harmful regulatory precedent under the RFS program. Furthermore, we do not believe there are any appropriate regulatory changes available that would accomplish the commenter's proposed alternative.

Commenter's alternative 4 is to delay the effective date of the changes to Row L until January 1, 2028, or later, giving parties time to register under the version of Row L that includes "Any process that converts cellulosic biomass to fuel." As discussed in Section X.D of the Set 2 proposal and Preamble Section VIII.D, the reason for the changes to Table 1 is to ensure that the statutory criteria are satisfied for RIN generation. Given that the purpose of these regulatory amendments is consistent with the statute, we do not believe it would be appropriate to unnecessarily delay them any further.

Commenter's alternative 5 is for EPA to commit to expedite the commenter's facility-specific pathway petition and approve it prior to the effective date of Table 1 modifications. We cannot commit to any approvals of petitions submitted under 40 CFR 80.1416 prior to evaluating them based on the statutory criteria. We also cannot commit to a date for a decision on a new pathway petition as the time it takes to complete a petition review is not specific in the regulations. We intend to work directly with this commenter to identify the most appropriate course of action to address their concerns. For example, if we determine that the commenter needs to submit a petition pursuant to 40 CFR 80.1416 requesting EPA's evaluation of a new fuel pathway, we will evaluate the petition. It is possible that the pathway will qualify for the cellulosic RINs that the commenter originally sought.

[228] EPA, "Renewable Fuel Pathway Screening Tool." https://www.epa.gov/renewable-fuel-standard-program/forms/renewable-fuel-pathway-screening-tool.

[229] "*Approved pathway* means a pathway that is 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."

11.4.2 Adding Waste Fats, Oils, and Greases as Feedstock for Producing Renewable Naphtha and LPG

Comment:

Multiple commenters expressed support for EPA's proposal to add generally applicable fuel pathways to Table 1 to 40 CFR 80.1426 for renewable naphtha and LPG produced from biogenic waste oils, fats, and greases through a hydrotreating process to qualify for D5 RINs.

Response:

We appreciate the commenters' support for this proposal.

Comment:

Several commenters indicated they did not necessarily dispute the new pathway for waste FOG as a feedstock for producing renewable naphtha and LPG in pathway I of Table 1 to 40 CFR 80.1426. However, the commenters recommended that EPA add all approved feedstocks for biodiesel to Table 1 of 40 CFR 80.1426. The commenters urged EPA to consider naphtha and LPG pathways the same as other feedstocks for biodiesel production.

Response:

Adding additional feedstocks to Row I is beyond the scope of this rulemaking. We only proposed to add "biogenic waste oils/fats/greases" to Row I. The commenter's request to add other feedstocks (*e.g.*, soybean oil, cottonseed oil) would require further evaluation by EPA and the opportunity for notice and public comment prior to adding these feedstocks to Row I.

11.5 Updates to Definitions

11.5.1 New Definitions

Comment:

A commenter expressed support for the proposed definitions of “renewable fuel producer,” “renewable naphtha,” and “renewable jet fuel.” They agreed with replacing text in existing regulations to use the new definitions and noted that replacing the term “non-ester renewable diesel” with the new definition for “renewable diesel” more accurately reflects industry trends. They also welcomed the updating of references to more recent revisions of ASTM and other industry standards.

Response:

We thank the commenter for their support.

Comment:

Multiple commenters recommended that EPA revise its proposed definition of “renewable jet fuel” to include ASTM D1655 in addition to ASTM 7566.

Response:

We agree with the commenters and have included ASTM D1655 in the final definition of “renewable jet fuel.”

Comment:

Several commenters requested that EPA keep the terminology “heating oil” rather than “renewable fuel oil” in Table 1 in 40 CFR 80.1426 to avoid confusion regarding its permitted use under the statute.

Response:

We agree with the commenters that use of the term “heating oil” should be retained in Table 1 to 40 CFR 80.1426 and as such are not replacing it with “renewable fuel oil” as proposed.

Comment:

Several commenters identified an error in EPA’s proposed definition of “renewable fuel oil,” which they stated mistakenly cross-referenced new paragraph (2) of the definition of “heating oil” instead of revised paragraph (1)(ii). They identified this problem because EPA was also proposing a new paragraph (2) to the definition of heating oil regarding the use of pure biodiesel and neat biodiesel for process energy. Referencing new paragraph (2), the commenters stated, would unnecessarily expand the end user affidavits and PTD requirements that currently only apply to fuel oil that is used to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort. The commenters requested that EPA amend the proposed definition of fuel oil to reference the new subparagraph (1)(ii) rather than subparagraph (2) to avoid confusion over what constitutes a fuel oil.

Response:

The commenters are correct that the proposed definition of "renewable fuel oil" mistakenly referenced paragraph (2) of the proposed definition of "heating oil," in which EPA proposed to revise the existing paragraph numbering and add a new paragraph (2). EPA did not intend to expand affidavit and PTD requirements as part of this proposed change. However, as discussed in Preamble Section VIII.B.2, EPA is not finalizing the proposed changes to the definition of "heating oil," and the existing definition and its structure will remain in place. Thus, the final definition of "renewable fuel oil" now correctly cross-references paragraph (2) of the definition of "heating oil."

11.5.2 Revised Definitions

Comment:

A commenter stated that the proposed addition of a joint and several liability provision on RIN importers under 40 CFR 80.1461 is not necessary.

Response:

Regardless of whether the explicit imposition of joint and several liability under 40 CFR 80.1461 is strictly necessary for EPA to impose such liability when enforcing the RFS program requirements, we believe such expression is beneficial to RFS program participants and the public. First, it ensures that all parties in the importation stream understand their liability under the RFS program. Second, we believe this addition to the regulations will support compliance with the RFS program requirements through the increased awareness and self-policing among importers.

11.5.3 New Biointermediates

Comment:

Several commenters expressed support for the inclusion of new biointermediates. One commenter stated their support for a new pathway for "converted oils" but said they were disappointed with EPA's inclusion of only two feedstocks and requested that soybean oil should be included as an eligible feedstock for the production of converted oils. The commenter argued that soybean oil should be approved in light of EPA's overestimate of the lifecycle emissions associated with soybean oil production and transport as a renewable fuel feedstock.

Response:

We thank the commenters for their support. Regarding the production of converted oils from soybean oil, we note that this was not part of the petition for rulemaking requesting the addition of converted oils.[230] As alluded to by the commenter, based on EPA's prior assessments, soybean oil is associated with greater lifecycle emissions than biogenic waste oils/fats/greases, such that we do not have assurance that biodiesel, renewable diesel, or other fuels produced from converted oils produced from soybean oil would satisfy the statutory 50% lifecycle emissions reduction criteria. Reevaluating EPA's prior lifecycle analysis of soybean oil is outside the scope of this rulemaking. For these reasons, we are not modifying the proposed definition of converted oils to include production from soybean oil.

Comment:

A commenter expressed concern about EPA's proposal to add activated waste sludge to the list of approved biointermediates, stating that EPA did not provide sufficient explanation as to how activated sludge meets the definition of "biointermediate" or why EPA cannot simply approve a pathway for it as a feedstock. The commenter expressed particular concern about this issue in light of numerous pending petitions for biogas-derived fuels and urged EPA to clear this backlog of petitions. Another commenter suggested that EPA ensure that the definition of activated sludge aligns with the use of "secondary wastewater treatment" as it related to 40 CFR 133 and how the use of activated sludge in a mixed digester would qualify for use.

Response:

As discussed in Preamble Section VIII.E.3, activated sludge is a biointermediate rather than a feedstock in cases where the activated sludge is produced at one facility and used to produce renewable fuel at a second facility. This is because activated sludge is produced from primary sludge that has been substantially altered through anaerobic and aerobic treatment.

[230] "DS Dansuk Petition for Addition of New Biointermediate Produced via a New Production Process," November 26, 2024.

The comment about the “backlog” of petitions for biogas-based fuels is outside the scope of this rule. EPA evaluates petitions for new pathways as expeditiously as possible based on the information provided by petitioners.

EPA agrees with the comment regarding the terminology in the definition of “activated sludge” and believes that it aligns with the use of “secondary wastewater treatment” in 40 CFR Part 133. Accordingly, EPA does not believe further modification to the definition is necessary. Stakeholders with questions about the use of activated sludge in mixed digesters are directed to contact fuelsprogramsupport@epa.gov for additional clarification.

11.6 Compliance Reporting, Recordkeeping, and Registration Provisions

11.6.1 Exempt Small Refinery Compliance Reporting

Comment:

Several commenters expressed support for EPA's proposal to require small refineries that have received an exemption to file annual compliance reports.

Response:

We thank the commenters for their support.

Comment:

Two commenters opposed the proposed clarification that exempted small refineries are not exempt from having to comply with any deficit RVOs that were carried forward from the previous compliance year. The commenters stated that this proposed requirement would negate the intent behind both the deficit carryforward provision and small refinery hardship relief.

Response:

We disagree with the commenters' interpretation of the small refinery exemption provisions. EPA believes that the best reading of the SRE provisions is that an exemption applies only to the gasoline and diesel fuel produced by a small refinery during the compliance year for which the small refinery sought and received an exemption. The ability for any obligated party—including a small refinery—to carry forward a compliance deficit from one compliance year to the next is separate and apart from the SRE provisions. Allowing a small refinery that receives an SRE to be exempt from its RVOs not only for the compliance year in which it petitioned for an exemption, but also for any deficit RVOs carried forward from the previous compliance year, is inconsistent with the RFS regulations, the CAA, and EPA's implementation of the SRE program for several reasons.

First, commenters are incorrect in their interpretation of what it means to receive an SRE. Receiving an SRE does not result in a blanket exemption for the compliance year that zeroes out all of the small refinery's RFS obligations under 40 CFR 80.1407(a) (*i.e.*, $[RVO_{CB,i}, RVO_{BBD,i}, RVO_{AB,i}, RVO_{RF,i}] \neq 0$); rather, an SRE exempts the gasoline and diesel fuel produced by the small refinery during the compliance year from incurring an RFS obligation (*i.e.*, $GV_i + DV_i = 0$ such that $[RFStd_{CB,i}, RFStd_{BBD,i}, RFStd_{AB,i}, RFStd_{RF,i}] * (GV_i + DV_i) = 0$). However, any RIN deficits from the previous compliance year (*i.e.*, $D_{CB,i-1}$, $D_{BBD,i-1}$, $D_{AB,i-1}$, and $D_{RF,i-1-1}$) remain and must be satisfied for the small refinery to demonstrate compliance with its RFS obligations (*e.g.*, $RVO_{RF,i} = RFStd_{RF,i} * (GV_i + DV_i) + D_{RF,i-1} = 0 + D_{RF,i-1} = D_{RF,i-1}$). Similarly, an exempt small refinery that also imports gasoline and diesel fuel would incur an obligation on the imported fuel as well. This is clear from EPA's regulations at 40 CFR 80.1407(a).

Second, commenters' interpretation is inconsistent with how EPA evaluates SRE petitions, which is to determine whether a petitioning small refinery experiences disproportionate economic hardship in the compliance year for which the refinery is petitioning for an exemption. As part of this evaluation, EPA considers the impact of the small refinery's RFS compliance costs for the gasoline and diesel fuel it produces for the compliance year in question. EPA does not consider the impacts of any RIN deficits carried forward from the previous year. Such an approach would incentivize petitioning small refineries to carry forward deficits in order to increase their RFS compliance costs in the subsequent compliance year, thereby increasing the likelihood of the small refinery receiving an exemption.

Third, the commenters' interpretation of the SRE provisions is inconsistent with CAA section 211(o)(5)(D)(ii), which requires that any obligated party that carries forward a compliance deficit must satisfy that deficit by generating or purchasing additional RINs in the following calendar year. Nothing in CAA section 211(o)(5)(D)(ii) indicates that this requirement is impacted by SREs under CAA section 211(o)(9). As noted elsewhere, obligated parties demonstrate compliance with the RFS obligations on an annual basis, and each SRE is associated with a single compliance year and does not apply to an obligation associated with a prior compliance year.

Fourth, we disagree with the commenters' interpretation of EPA's deficit regulations in 40 CFR 80.1427(b). While the formulas in this regulatory section require the retirement of RINs associated with the deficit in the following compliance year, this does not amount to the obligations "merging" as the commenters suggest. Furthermore, while the provision creates flexibility by allowing obligated parties that choose to carry forward a deficit to use future-year RINs, that does not indicate that the obligations "merge" such that a small refinery that receives an SRE is exempted of both its obligations associated with the compliance year for which it received the exemption and the carryforward deficit associated with the prior compliance year.

Finally, the commenters' interpretation of the SRE provisions ignores the CAA's requirement that exemptions can only be granted on the basis of disproportionate economic hardship. For example, if a small refinery petitioned for a 2026 exemption and was denied, it could then carry forward its entire 2026 RVO into 2027 and petition for a 2027 exemption. Under the commenters' interpretation, if the small refinery is then granted a 2027 exemption, both the 2026 and 2027 RVOs would be exempted even though EPA had previously assessed the impact of 2026 compliance on the small refinery and found that it would not incur disproportionate economic hardship. Such an outcome is contrary to the statute and implementing regulations.

11.6.2 Compliance Report Updates

Comment:

Several commenters expressed support for EPA's proposed efforts to streamline reporting requirements under the RFS program, including changes to the production outlook report under 40 CFR 80.1449 and quarterly reporting requirements under 40 CFR 80.1451.

Response:

We thank the commenters for their support.

Comment:

One commenter suggested that EPA include renewable jet fuel in the list of the fuels exempt from quarterly reporting requirements under 40 CFR 80.1451(b)(1)(ii)(T) as there are no reasonable alternative uses for renewable jet fuel other than as a transportation fuel.

Response:

Consistent with the commenter's request, EPA proposed to exempt renewable jet fuel from the quarterly reporting requirements under 40 CFR 80.1451(b)(1)(ii)(T) and is finalizing that change in this action.

Comment:

One commenter expressed concern that EPA's proposed updates to the "reason codes" reporting requirement lacked clarity. The commenter recommended that EPA address these changes in a separate action and work with stakeholders on the specific amendments to the regulatory requirements.

Response:

The reason codes are designed to further improve implementation of the RFS program through EMTS. We will first implement generation reasons specific to areas such as report corrections, which will directly enable the automated processing of these requests. This is responsive to and addresses other comments that processing of report corrections by EPA is consistently delayed. We will continue to monitor feedback from industry on the use of these reason codes in order to continue improving implementation and compliance efforts after the initial pilot in 2026. Additionally, all codes and associated compliance assistance information will be integrated into EPA's existing system documentation on EMTS, which is publicly maintained on EPA's website.

Comment:

One commenter suggested that EPA remove the "etc." in parentheses under 40 CFR 80.1452(b)(18).

Response:

This list in 40 CFR 80.1452(b)(18) is intended only to provide examples and is not exhaustive; however, we agree with the commenter that the “etc” following “*e.g.*” in the parenthetical is redundant. Therefore, we have removed the “etc.” consistent with the commenter’s suggestion.

11.6.3 Third-party Auditor Registration Renewal

Comment:

Several commenters expressed support for EPA’s proposal to change the frequency of independent third-party auditor registration renewals from annual to biennial. The commenters stated that reducing the renewal frequency would decrease burdens on auditors.

Response:

We thank the commenters for their support.

11.6.4 Engineering Review Site Visits

Comment:

Several commenters expressed concerns about EPA's proposal to require site visits for engineering reviews to be conducted within six months prior to submitting a registration request. The commenters cited potential challenges including a limited number of qualified engineers to conduct such reviews and possible delays in submitting registration materials that may be unrelated to facility changes or the validity of the engineering review. As an alternative approach, commenters suggested that producers could submit a certification stating that no changes have been made to the facility since the date of the site visit.

Response:

We believe that it is critical that the engineering review site visit accurately reflects the current operations of the facility. A recent site visit (*i.e.*, July 1 or later of the calendar year prior to the applicable January 31 deadline) from an independent third-party engineer is already required for registered facilities as part of their three-year engineering review updates under 40 CFR 80.1450(d)(3)(v). The new requirement that initial registration requests also include a recent site visit (*i.e.*, conducted in the previous six months) is consistent with this existing requirement for registered facilities.

As described in Preamble Section VIII.F.4, EPA has recently received engineering reviews in which the site visit occurred over a year prior to the registration request and we have significant concerns as to whether such site visits are still an accurate representation of the registering facility. The six-month requirement we have finalizing in this action will better ensure confidence that the engineering review site visit is an accurate representation of the current operations of the facility. We do not believe that theoretical concerns about a shortage in engineer availability are sufficient reason to allow producers to self-certify that there have been no operational changes since the last site visit. We have concerns that such a flexibility could be abused by registering facilities to avoid the cost of hiring an engineer to conduct a site visit, when in fact the facility looks significantly different from the last site visit.

11.6.5 Biogas Batch Period of Production

Comment:

Several commenters expressed support for EPA's proposed revision to the biogas batch period of production. The commenters stated that allowing a biogas batch to be "up to" a calendar month would provide the industry with needed flexibility in defining a batch.

Response:

We thank the commenters for their support.

Comment:

One commenter asked EPA to provide more clarity on whether the calendar month can straddle across multiple months.

Response:

While EPA is providing flexibility that a biogas batch may be "up to" a calendar month, that batch must still be for biogas produced during the calendar month. Thus, a biogas batch cannot include biogas produced during two different calendar months.

11.7 New Approved Measurement Protocols

Comment:

Many commenters expressed strong support for EPA's proposal to add additional measurement protocols to 40 CFR 80.155(a) and the addition of EPA Method TO-15 and ASTM D1945 as methods for hydrocarbon analysis. Several of the commenters recommended including the following additional measurement methods: ISO 14511, ASME MFC-11, ISO 10790, ISO 17089-1, and ISO 11631.

Response:

We thank the commenters for their support and have added most of the additional methods identified by the commenters—which are already included in approved alternative monitoring plans (AMPs)—to the list of approved measurement methods in 40 CFR 80.155(a).[231] The exception is ISO 11631, which is not listed on EPA's AMP website and is instead an informative reference document and not a standard for a specific meter type. In addition, we have added ASME MFC-3M and ASME MFC-12M to the list of approved methods in 40 CFR 80.155(a), as these methods have also been approved by EPA in AMPs.

Comment:

One commenter suggested adding additional methods for measurement of biogas and RNG samples, including ASTM D1945, ASTM D1946, and ASTM D7833 for measuring hydrocarbons and major gases (methane, carbon dioxide, nitrogen, and oxygen); ASTM D1142 and ASTM D5454 for measuring moisture; and ASTM 6228 and ASTM D6968 for measuring sulfur.

Response:

We agree with the commenter and have added the suggested methods as additional methods for measurement of biogas and RNG samples.

Comment:

One commenter recommended incorporating language pertinent to data substitution in 40 CFR 135(c)(3)(i) and 135(d)(3)(i) to address uncertainty over missing data regarding metered biogas or RNG production. The commenter suggested that EPA should aggregate the accepted data substitutions and release conservative methodologies that can be used by any fuel pathway holder.

[231] 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.

Response:

We did not request comment on or otherwise include provisions related to data substitution in the proposed rule and thus are not taking final action on such provisions in this action. However, we agree with the commenter that this is an important issue and will consider taking action on it in a future rulemaking.

Comment:

Numerous commenters expressed concern with the proposal to test and calibrate flow meters under OIML R137-1 and 2. Some commenters recommended that the proposed rule include guidance that defers to the OEM standards by device, adding that listing alternative measurements in the regulation and then potentially imposing incompatible or impractical testing and calibration requirements seems contrary.

Response:

We have reviewed the approved flow meter methods in the regulations and found that they include their own guidelines or methodology for calibrating the flow meter. Thus, we agree with commenters that it is not necessary to specify an additional calibration method in the regulations and have removed the requirement to calibrate meters using OIML R137-1 and 2.

11.8 Biodiesel and Renewable Diesel Requirements

Comment:

Several commenters supported EPA clarifying that batch testing is required for producers to demonstrate that their renewable diesel and biodiesel adhere to 40 CFR part 1090 requirements. One commenter encouraged EPA to exempt biodiesel from the aromatics requirement because it adheres to ASTM D6751.

Response:

We thank the commenters for their support of our clarification, which was also previously made in the Fuels Regulatory Streamlining final rule.[232] As stated in that rule, biodiesel that meets ASTM D6751 is exempt from cetane index and aromatics testing under 40 CFR part 1090. Conversely, biodiesel blends or biodiesel that does not meet ASTM D6751 are not exempt from cetane index and aromatics testing. This is to ensure that only biodiesel that meets ASTM D6751 can be exempt from aromatics and cetane index testing and that parties do not create biodiesel blends as a mechanism to avoid the diesel fuel cetane index and aromatics standards.

With regard to the commenter's request that EPA exempt biodiesel from the aromatics testing requirement, such language already exists in 40 CFR 1090.1350(b)(2) ("There is no aromatics-related test requirement for biodiesel that meets ASTM D6751.").

Comment:

One commenter suggested that EPA revise the proposed language in 40 CFR 1090.300(a)(3) to state that "Biodiesel blends or biodiesel that does not meet ASTM D6751 remain subject to the cetane index or aromatic content standards in 1090.305(c)."

Response:

We agree with the commenter and have revised the language in 40 CFR 1090.300(a)(3) as suggested by the commenter.

Comment:

A commenter stated that EPA should use a consistent definition of "biodiesel" in 40 CFR parts 80 and 1090.

Response:

The 40 CFR part 80 and 1090 definitions of biodiesel serve different purposes. Renewable fuel producers must produce biodiesel that meets ASTM D6751 in order to generate RINs under the RFS program, as specified in the part 80 definition of biodiesel. This ensures that biodiesel for

[232] 85 FR 78442 (December 4, 2020).

which RINs are generated is of a sufficient quality to be used as transportation fuel as required under the CAA. Under 40 CFR part 1090, consistent with 40 CFR part 80, biodiesel is subject to EPA's diesel fuel standards regardless of whether the biodiesel meets ASTM D6751 or RINs are generated for the fuel.

11.9 Extension of RFS Compliance Reporting Deadlines

Comment:

Several commenters supported the proposed automatic extension of RFS compliance reporting deadlines. Some commenters stated that the proposed automatic extension balanced burdens on regulated parties and compliance within an appropriate timeframe. Other commenters stated that the extension of compliance reporting was necessary for regulated parties to adapt when EPA changed the RFS requirements within a compliance year because of the uncertainty those changes might introduce.

Response:

We thank the commenters for their support.

Comment:

Several commenters stated that the proposed automatic extension of RFS compliance deadlines is unnecessary. Some commenters stated that the regulatory burden from any changes to the RFS program should be manageable in circumstances where EPA uses its waiver authority, while other commenters worried that the proposed automatic extension would set a bad precedent and that the provision would create perverse incentives to apply for waivers in order to delay compliance deadlines. A couple of commenters believed the provision would undermine the program's integrity and introduce instability in the RIN market.

Response:

We disagree with the commenters that adding the new compliance date extension provision is not necessary. Under the current RFS regulations, the presumed compliance deadline for a given compliance year is generally March 31st of the subsequent year (assuming the standards for subsequent year are in place). Generally, it is not clear that EPA may need to consider using one of its waiver authorities (*e.g.*, cellulosic waiver authority) until late in the compliance year when RIN generation data for most of the year is available; EPA may even consider waiting until full-year RIN generation data is available in January or February of the subsequent year before deciding to propose a waiver of the standards. This would give EPA no more than two or three months to propose a rule, hold a public hearing, solicit comments for 30 days after the public hearing, and then finalize the rule before the otherwise applicable March 31 compliance deadline. While EPA could propose to extend the compliance deadline for the compliance year in question as part of the same rule (as it did for the 2024 compliance year), this creates an extraordinary amount of work and burden for EPA to finalize the extension of the compliance deadline before the otherwise applicable March 31 deadline. Furthermore, as part of the proposed waiver for the 2024 compliance year, EPA proposed to extend the 2024 compliance deadline to the next quarterly reporting deadline after the effective date of the rule that finalizing the waiver of the 2024 standards.[233] This is the same outcome that would have resulted had the

[233] 89 FR 100449 (December 12, 2024).

automatic compliance deadline extension provisions been in place, except that under these new provisions EPA would not have had to spend additional time and resources to quickly finalize the extension before the otherwise applicable March 31 compliance deadline.

Contrary to commenters' assertions, we believe that these new provisions will create *more* stability in the RIN market. RFS stakeholders now know that if EPA proposes to use one of its waiver authorities to revise a standard for a given compliance year, obligated parties will have at least 60 days after EPA takes final action to adjust their compliance strategies based on the revised standards. This creates more certainty in the RIN market, not less, as obligated parties are not forced to make rushed decisions while they wait to see if EPA is able to extend the otherwise applicable compliance deadline in time.

Furthermore, commenters' supposed fear that EPA would abuse these new provisions and unnecessarily propose to revise standards simply to extend compliance deadlines are unfounded. It is not petitioning by obligated parties or other market participants for a waiver that triggers the automatic extension of the compliance deadline. Rather, the deadline is only extended by a proposed action by EPA to waive a standard, which requires careful consideration and evaluation of the factors and conditions laid out in the statute to use the waiver authority. There is no greater incentive for obligated parties to petition for a waiver now than there was before the automatic compliance date extension provisions were in place, as were these provisions not in place and EPA proposed a waiver, EPA would still propose to extend the compliance deadline at the same time, as it did for the 2024 standards. The new automatic compliance deadline extension provisions simply reduce the burden on EPA and uncertainty for stakeholders as to when compliance will ultimately be required for a given compliance year.

Comment:

Several commenters expressed concern that the compliance deadline could be extended based on a "mere proposal" issued by EPA rather than a final action. The commenters raised concerns about the procedural aspects of the proposed revision because they are not binding. The commenters worried that the ability for EPA to propose a change and guarantee an automatic extension bypasses public comment and judicial review of future compliance extensions.

Other commenters stated that EPA is attempting to exceed its authority by adding an automatic extension for compliance reporting deadlines and that the provision is "unlawful and arbitrary." One commenter claimed that this proposed provision defies Congressional intent for the RFS program and its limits on EPA's authority and further claimed that Congress would need to expressly grant EPA permission to add this provision. The commenter also claimed that this provision would violate the Congressional mandate for the RFS program to ensure volume requirements are met. Finally, the commenter claimed that automatic extensions would impact subsequent compliance years with no justification, in excess of EPA's existing authority.

Several commenters raised concerns about EPA's observation of the 90-day waiver decision window. Both commenters argued that by adding automatic extensions, EPA would be inappropriately exceeding this Congressionally mandated window in which to make waiver decisions. One commenter stated that EPA cannot grant itself the authority to ignore this decision window.

Response:

EPA has broad authority in the way it establishes the RFS compliance deadlines, as there is no statutorily mandated annual compliance deadline. As part of EPA's implementation of the RFS program, it has changed the compliance deadline provisions on numerous occasions. Under the original RFS2 provisions, RFS compliance was required annually by February 28.[234] EPA later extended the annual compliance deadline to March 31.[235] After a series of compliance deadline extensions for numerous compliance years, EPA established regulatory provisions that set the annual compliance deadline to be the latest date of the following:

- March 31st of the subsequent calendar year;
- The next quarterly reporting deadline after the effective date of the final rule establishing the subsequent compliance year's RFS standards; or
- The next quarterly reporting deadline after the annual compliance reporting deadline for the prior compliance year.[236]

The D.C. Circuit upheld EPA's approach to establishing a dynamic compliance deadline that is based on other actions by EPA (*e.g.*, when EPA establishes the RFS standards for the subsequent compliance year).[237] The automatic compliance date extension provisions EPA is establishing in this final rule are no different and commenters are incorrect in their claim that the Court's holdings in *Wynnewood* are not relevant to EPA's authority to do so. Here, as in *Wynnewood*, EPA has created provisions that are designed to ensure that the annual renewable fuel volumes are met and avoid unnecessary overcompliance by obligated parties when EPA uses its authority to revise the standards. We recognize that the "trigger" to extend the compliance deadline is not a final agency action that can be challenged; however, we do not find this distinction compelling. Notably, a stakeholder could not challenge a final rule (*e.g.*, this action, which will set the compliance deadline for the 2025 and 2026 standards) on the basis that it set the compliance deadline. Instead, stakeholders would have needed to challenge the original action establishing the regulations.[238] Thus, the fact that a party cannot challenge the proposal that will extend the compliance deadline is not relevant.

As detailed above, the automatic compliance date extension provisions will provide more certainty to stakeholders and reduce burden on both obligated parties and EPA. Were EPA to propose to revise a standard but fail to extend the compliance date before the deadline passed, obligated parties would be required to comply with the existing standards. Then, after EPA later finalizes the revised standards, EPA would have to reopen compliance for all obligated parties,

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[234] 75 FR 14676 (March 26, 2010).
[235] 79 FR 23576-77 (April 28, 2014).
[236] 87 FR 5696 (February 2, 2022).
[237] *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.").
[238] Several parties did challenge that action, and the regulation was upheld in *Wynnewood*.

likely returning all the RINs obligated parties had previously retired for compliance. Obligated parties would then have to develop a new compliance strategy, buy additional RINs or sell excess RINs, and then refile compliance reports with EPA. This creates a significant amount of unnecessary extra work for both EPA and obligated parties. By finalizing the automatic compliance date extension provisions in this final rule, obligated parties will no longer have to worry about whether they need to comply with standards that EPA is actively considering revising by EPA's action to propose revising the standards.

We do not find that the 90-day deadline in CAA section 211(o)(7)(B) bears on EPA's ability to extend compliance deadlines. While EPA is finalizing provisions that extend compliance deadlines based on EPA's proposed waivers under this and other provisions, this does not mean that EPA is eliminating the 90-day deadline. The deadline in CAA section 211(o)(7)(B) is unaffected by this action.

Comment:

One commenter requested that EPA clarify a timeline under which compliance extensions are in place when EPA takes no action after a proposed revision to the RFS requirements. The commenter stated that the final provision should specify that if EPA has not finalized or withdrawn the proposed revision within a specified period, then the compliance deadline will be automatically extended to 12 months following the specified period.

Response:

We believe that the proposed regulations already address the scenario raised by the commenter. 40 CFR 80.1451(f)(1)(1)(i)(C)(*3*) provides that if EPA does not finalize or withdraw the proposed revision to the RFS requirements within 12 months after the date of the proposed rule (*i.e.*, EPA takes no action), the compliance deadline is the later of the next quarterly reporting deadline that is 12 months after the date the proposed rule was published in the *Federal Register* or the otherwise applicable reporting deadline under 40 CFR 80.1451(f)(1)(i)(A) or (B). Thus, we do not believe any changes to the proposed regulations are necessary and we are finalizing the provision as proposed.

11.10 Biogas Regulations

11.10.1 Measurement, Sampling, and Testing

Comment:

Many commenters expressed support for the proposed changes and clarifications to the biogas regulations.

Response:

We thank the commenters for their support.

Comment:

Several commenters expressed their support for the proposed revision to 40 CFR 80.110(f)(2)(iii) that biogas and RNG testing would be required every three years instead of annually.

Response:

We thank the commenters for their support and are finalizing the change to the biogas and RNG sampling and testing requirement such that sampling and testing is only required at least once every three years instead of annually. We have also added clarifying text to 40 CFR 80.110(f)(2)(iii) to specify that such sampling and testing is required for three-year engineering reviews that are submitted on or after January 1, 2027.

Comment:

A commenter stated that the requirement for C-14 testing should be removed as it is very expensive and has not typically been required for biogas or RNG. The commenter stated that there are more adequate protections under the biogas reforms and the QAP verification to ensure against fossil natural gas being added to biogas or RNG.

Response:

40 CFR 80.135(d)(6)(iii) states that "[if] the RNG is blended with non-renewable components prior to injection into a natural gas commercial pipeline system, a certificate of analysis from an independent laboratory for a representative sample of the RNG after blending with non-renewable components as specified in § 80.155(b)." While 40 CFR 80.155(b)(2)(vii) requires C-14 analysis using ASTM D6866, only RNG producers that blend RNG with non-renewable components are required to perform C-14 testing under 40 CFR 80.135(d)(6)(iii). We have added clarifying language to 40 CFR 80.155(b)(2)(vii) that only RNG producers that blend non-renewable components into RNG are required to do C-14 testing. As specified in 40 CFR 80.1426(f)(9), such testing is necessary to measure the renewable fraction of the blended natural gas and ensure that the appropriate number of RINs are generated for the RNG. Thus, we do not

agree that this requirement should be removed, as it only applies to producers blending RNG with non-renewable components.

Comment:

A commenter recommended that ASTM D6866 testing requirements should be increased from annually to quarterly, rather than decreased to every 3 years, to align with other biogenic content measurement requirements. The commenter emphasized that ASTM D6866 Method B is the most accurate and reliable method for C-14 testing and should be the only method permitted.

Response:

Under the RFS program, RNG must be produced from biogas, which is composed of biomethane, inert gases, and impurities and cannot contain added non-renewable components. Non-renewable components can only be blended with RNG prior to injection into a natural gas commercial pipeline system. This is a different situation from the co-processing of other renewable fuels under the RFS program where renewable and non-renewable feedstocks are processed simultaneously. Given that both the non-blended RNG and the non-renewable components must be separately metered, EPA does not believe that C-14 testing should be required more often than every three years.

Comment:

A commenter expressed their support for the proposed revision to 40 CFR 80.135(d)(6)(v) to allow EPA to approve alternative methods other than those specified in 40 CFR 80.155(b)(2).

Response:

We thank the commenter for their support.

Comment:

A commenter requested that EPA allow approval of alternative methods if they provide reasonably accurate information or if the alternative analysis is required by pipeline specifications or has been approved by a State or Federal government agency.

Response:

We agree with the commenter that additional flexibility and clarity would be helpful to help industry understand how EPA will assess the accuracy of alternative test methods. As such, we have incorporated the commenter’s suggested language regarding the alternative analysis being required by pipeline specifications or having been approved to be used by a State or Federal government agency.

Comment:

A commenter said that the proposed amendment for RNG producers to allow for alternative analysis adds more flexibility, but it only references 40 CFR 80.155(b)(2), which lists analysis methods to apply for listed constituents. The commenter suggested that an alternative analysis be considered for acceptance for the sample collection method as well as the analysis methods.

Response:

We agree with the commenters that allowance of alternatives to the test methods in 40 CFR 80.155(b)(2) should be expanded to cover paragraph (b)(1). We have revised the regulations accordingly to reference 40 CFR 80.155(b).

Comment:

Several commenters expressed support for the proposed removal of the requirement for an RNG producer to test for a certain parameter if the parameter is not included in the pipeline specifications submitted at registration.

Response:

We thank the commenters for their support and are removing the requirement to test for certain components as proposed.

Comment:

Several commenters expressed support for the proposed clarification of the approval process for alternative test methods and the exemptions for non-specified components.

Response:

We thank the commenters for their support.

Comment:

A commenter said that 40 CFR 80.155(b)(2)(vii) continues to list "[a]dditional components specified in the natural gas specifications submitted under § 80.135(d)(5) or as specified by EPA as a condition of registration under this part."

Response:

We proposed to remove 40 CFR 80.155(b)(2)(vii) as requested by the commenter ("b. Removing paragraph (b)(2)(vii); and" 89 FR 100445). We are finalizing removal of this paragraph as proposed, consistent with the commenter's suggestion.

Comment:

A commenter suggested modifications to the language in 40 CFR 80.155(b) to align with the proposed revision to 40 CFR 80.135(d)(6)(v).

Response:

We have moved the proposed language from 40 CFR 80.135(d)(6)(v) to 40 CFR 80.155(b); thus, the commenter's suggested revisions to 40 CFR 80.155(b) are not necessary.

Comment:

A commenter suggested that EPA provide an alternative method to EPA Test Method 18 since the commenter was not aware of any laboratory performing this test method and indicated an acceptable alternative method is TO-15.

Response:

We proposed to include TO-15, as well as ASTM D1945, as acceptable hydrocarbon analysis methods under 40 CFR 155(b)(2)(v) in the Set 2 proposal and are finalizing inclusion of these methods as proposed.

Comment:

Several commenters expressed support for the proposed revisions to describe why an RNG or biogas producer cannot use specified meters is not necessary to ensure the accurate precise measurement of biogas and RNG.

Response:

We thank the commenters for their support and are removing the requirement to describe why a party is unable to use certain specified meters as proposed.

Comment:

Several commenters suggested that EPA revise 40 CFR 80.135(c)(3)(i) and (d)(3)(i) to only require describing the "specific standards under which the meters are operated" for biogas and RNG when applicable.

Response:

We agree with the commenters and have revised the regulations as suggested.

Comment:

A commenter expressed their support for the proposed revision to 40 CFR 80.155(a)(2)(ii) allowing the use of gas analyzers accepted by EPA at registration instead of the currently specific GCs. The commenter agreed with EPA's intent to forgo the alternative measurement protocol process for biogas measurement devices and instead assess on a case-by-case basis at registration. However, the commenter requested clarification on what that assessment will include and whether their gas analyzer would meet the "continuous measurement" requirement.

Several other commenters stated their support of EPA allowing the use of gas analyzers for biogas in lieu of GCs but urged EPA to specify the gas analyzers it has approved in the regulations to help streamline the registration process.

Response:

We are not finalizing the proposed revision to allow biogas producers to forgo the alternative measurement protocol process for biogas measurement devices. As the commenter pointed out, we did not specify in the proposal what our assessment of gas analyzers would entail or what information should be submitted. Given that the proposed revision would have created a potentially confusing gap in the regulations, we decided it is better not to finalize it at this time. The already existing alternative measurement protocol process has been used successfully to allow for the use of gas analyzers, so we are leaving that process in place.

Furthermore, based on our review of hundreds of biogas facilities that have registered with us, it would be difficult to specify a one-size-fits-all approach of approved gas analyzers. However, the regulations do allow parties to request an alternative measurement protocol, which EPA will review on a case-by-case basis.

Comment:

Several commenters suggested additional flow meter measurement methods that EPA should include in 40 CFR 80.155(a)(1) to reduce the burden on new facilities to prepare and submit AMPs when methods have already been approved.

Response:

We proposed to include the flow meter methods suggested by the commenters under 40 CFR 80.155(a)(1) in the Set 2 proposal and are finalizing inclusion of these methods as proposed.

11.10.2 Other Amendments

Comment:

Several commenters expressed their support for the other amendments that clarify the annual attest engagement procedures and update the registration requirement for RNG RIN separators.

Response:

We thank the commenters for their support.

Comment:

Several commenters expressed support for the proposed revision to 40 CFR 80.115(b). However, some of the commenters stated that EPA does not explain how it will/can confirm the requirement that only one party may actually separate RINs for a given CNG/LNG dispensing location during a calendar month to prevent double counting of RINs, based on the limited data that is made publicly available. In addition, one of the commenters stated that EPA has not addressed an open question regarding the process for RNG RIN separators to receive confirmation from EPA that they are in compliance with the measurement requirements.

Response:

We are finalizing the removal of RNG RIN separation location registration restrictions as proposed. We understand commenters' concerns and appreciate the suggestions for preventing invalid RIN separation in cases where dispensing locations have multiple registrants. EPA generally does not publicize a registrant's reporting activity except in a highly aggregated format but will further explore the suggestion for publicizing RNG RIN separation activities. In the meantime, we will monitor separation activities and in cases where it appears that multiple parties have separated RNG RINs at the same location, in the same month, notify all parties involved that RINs are potentially invalid for not meeting dispensing location limitations at 40 CFR 80.125(d)(2)(v).

One commenter noted that there is a lack of confirmation in the registration process for RNG RIN separators regarding measurement requirements. We recently revised 40 CFR 80.155(a) to allow RNG RIN separators to use documentation such as pipeline or utility statements, scale tickets, or bills of lading to establish volumes of CNG/LNG. See 90 FR 29751 (July 7, 2025).

Comment:

One commenter expressed support for codifying the clarification for requirements for RNG RIN assignment in 40 CFR 80.125(c)(3). However, the commenter, along with another commenter, stated that EPA should make clear that "corresponding volume of RNG" does not mean physical volumes of RNG and that no physical gas transfers are necessary when transferring assigned RNG RINs and that physical gas does not need to be held by an entity holding assigned RNG RINs.

Response:

We have clarified in 40 CFR 80.125(c)(3) that any party purchasing RINs assigned to a volume of RNG is deemed to also be acquiring a corresponding volume of RNG for purposes of 40 CFR part 80 (*i.e.*, the RFS program). In this way we are establishing consistent treatment of assigned RINs between RNG and other renewable fuels without requiring an RNG producer to transfer the exact volume of RNG used for RIN production. This balances the need to ensure assigned RINs remain associated with a quantity of RNG until they are separated but does not require burdensome tracking or direct RNG transfers.

Comment:

Two commenters suggested that EPA clarify language in 40 CFR 80.140(e)(2) to make sure that reporting requirements for "each batch of biogas" are consistent and appropriate for the volumes being dispensed.

Response:

We agree with the commenters that the provisions in 40 CFR 80.140(e)(2) apply to renewable CNG/LNG rather than batches of biogas and have revised the regulation as suggested by the commenters.

Comment:

A commenter requested additional clarification on the word "point" in proposed 40 CFR 80.135(f)(2).

Response:

The word "point" means the withdraw point for RNG taken from the natural gas commercial pipeline system consistent with the definition of pipeline interconnect at 40 CFR 80.2. The commenter does not provide sufficient detail to provide further clarification for their situation. Questions should be directed to fuelsprogramsupport@epa.gov.

Comment:

A commenter stated that EPA should update the current definition of "Assigned RIN" to include RINs with a K code of 3.

Response:

We agree with the commenter that the definition of assigned RINs should also include RINs with a K code of 3 and have updated the regulations throughout 40 CFR part 80 to add references to a K code of 3 where appropriate.

Comment:

A commenter suggested that the definition for "Continuous Measurement" should be updated to allow for calculations to be performed with 15-minute averaged data. The commenter said that the increase in data frequency to one-minute data for the calculation of volumes of biogas and RNG, has significantly increased the monthly data to be handled, and it is creating practical issues.

Response:

We appreciate the concern raised by the commenter regarding data management. While we did not propose to revise the definition of continuous measurement as suggested by the commenter and thus are not making any changes in this final rule, we have added language to 40 CFR 80.155(a)(3) to clarify that alternative measurement protocols may include less frequent measurement or recording than specified in the definition of continuous measurement. Thus, if a party desires a less frequent data measurement or recording approach that they believe is at least as accurate and precise as the applicable methods specified in 40 CFR 80.155(a)(1) and (2), they should submit an alternative measurement protocol request to EPA.

Comment:

A commenter suggested review and clarification of the enumeration for the proposed revision in the added paragraph to 40 CFR 80.155(a)(4).

Response:

We have reviewed the paragraphs identified by the commenter and found them to be incompliance with OFR guidelines regarding CFR structure and paragraph numbering. Regarding 40 CFR 80.155(a)(4)(ii) specifically, we believe that the commenter was reviewing a pre-publication version of the proposed rule, which originally numbered this paragraph as 80.155(a)(4)(B). This error was corrected during pre-publication review by the Office of the Federal Register.

11.11 Technical Amendments

Comment:

One commenter stated that the clarification in the definition of “MVNRLM diesel fuel” that ASTM D86 be used to measure T90 would be inappropriate because using this test method for biodiesel samples would create unsafe conditions for lab technicians.

Response:

The requirement to use ASTM D86 to measure T90 referenced by the commenter only applies to distillate fuel with a T90 at or above 700 °F that is used in Category 2 and 3 marine engines, in which case such fuel is not considered MVNRLM diesel fuel. Biodiesel is not a distillate fuel (*e.g.*, see paragraph (1)(ii) of the definition of “diesel fuel,” which uses biodiesel as an example of a non-distillate fuel) and thus would not be subject to this requirement. As such, we are finalizing the requirement in the definition of “MVNRLM diesel fuel” to use ASTM D86 to measure T90 as proposed.

Comment:

Several commenters opposed EPA’s proposed revision to 40 CFR 80.125(e)(2), arguing that it was not merely a clarification but would appear to reduce the life of the RNG RIN. The commenters explained that this proposed change would appear to require separation within three months of the end of the year or the RNG RIN would expire.

Response:

EPA did not intend to require RNG RINs be separated in as short a time as three months after the end of the year but instead intended to clarify an example in the regulations of when expired RNG RINs must be retired. We have revised the final regulatory language in 40 CFR 80.125(d)(5) to clarify that assigned RNG RINs expire on December 31 of the subsequent calendar year after the RIN was generated and that RNG RINs that are not separated by this date are expired. This ensures that RNG RINs have a minimum 12-month lifespan after they are generated. Furthermore, we have revised the final regulatory language in 40 CFR 80.125(e)(2) to clarify that expired RNG RINs must be retired by March 31 of the subsequent calendar year after the RINs expired and added an updated example of such RIN expiration and retirement.

Comment:

A commenter opposed EPA’s proposal to change the definition of “Responsible corporate officer” under 40 CFR 1090.80 by removing “operations manager” as an example from the definition with providing adequate explanation of the change. The commenter argued that the general manager of a biodiesel plant should be able to serve as a responsible corporate officer as they are often closest to the facility.

Response:

The change to this definition does not prevent an operations manager at a biodiesel plant from acting as an RCO; however, because of the vagueness of authority granted to “managers” across industries, we are removing that title from the list of positions that are presumed to have RCO authority. An operations manager would need to provide documentation such as company by-laws to show that they have the proper authority to be an RCO.

Comment:

A commenter supported the proposed removal of the expired Option A and Option B QAP provisions from several sections of the regulations, as doing so will limit confusion among regulated parties and agency staff.

Response:

We thank the commenter for their support.

Comment:

A commenter stated that EPA should correct Table 2 to Paragraph (b)(3)(ii) of 40 CFR 1090.215 to reflect the current implementation schedule for removal of the 1.0 psi RVP waiver for the affected Midwestern states.

Response:

We have corrected the table as suggested the commenter.

12. Other Comments

12.1 Executive Orders

Comment:

Two commenters stated that EPA should withdraw its proposed no SISNOSE determination and instead engage in consultation with small refiners as part of an Initial Regulatory Flexibility Analysis. Commenters stated that EPA's proposed determination was based on a flawed analysis and speculated that EPA used sales data from 2023 for its analysis, which would not be appropriate since that was an anomalous year across the industry. The commenters further stated that EPA cannot provide only a "cursory explanation" to "summarily conclude" the Proposal would result in no SISNOSE. Specifically, commenters argued the following:

- EPA's RIN cost passthrough principle in Method 1 has been rejected by courts and determined to not be applicable to small refineries, which are unable to recover their costs in the prices of the fuels they sell.
- EPA should have used higher RIN prices in its Method 2 analysis and should not have assumed that RINs are purchased ratably.
- EPA should use a No RFS baseline instead of a 2025 baseline in its Method 2 analysis.
- EPA should have used a cost-to-profit ratio instead of cost-to-sales.
- EPA should have considered the average profit margin of small refiners and used a threshold lower than 1%.
- EPA should consult with small refiners to minimize the impact of the rule.
- EPA should disclose the identities and information of the small refiners that were considered in the screening analysis.

Response:

First and foremost, 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 in 2010[239] and reviewed again under RFA section 610 in 2020.[240] We discuss our assessment of these impacts more fully in Preamble Section XI.D.

Setting that aside, commenters misconstrue the courts' findings regarding EPA's RIN cost passthrough principle. EPA continues to believe that all obligated parties—including small refiners—recover their RFS costs of compliance through the higher sales price of the gasoline and diesel they sell. While the D.C. Circuit in *Sinclair* found small refineries' arguments that they cannot always purchase RINs ratably to be compelling,[241] the court agreed with EPA in its subsequent decision in *CBD* that the principle as applied to the entire transportation fuel market

[239] 75 FR 14670, 14735-39 (March 26, 2010).
[240] 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
[241] *Sinclair Wyo. Ref. Co. LLC. v. EPA*, 114 F.4th 693, 712-14 (D.C. Cir. 2024) ("*Sinclair*").

is still valid.[242] EPA analyzed the cost of purchasing separated RINs relative to the cost of acquiring RINs by blending renewable fuel on multiple occasions, beginning in 2015 with the Burkholder Study,[243] and again in 2016 and 2017 when EPA evaluated the RIN market as part of its consideration of petitions to change the RFS point of obligation.[244] EPA found that, on average, the cost of purchasing separated RINs was equal to the cost of acquiring RINs by blending renewable fuel. Our analysis of pricing data demonstrated that parties that blend renewable fuels discount the price of the fuel they sell to account for the value of the RINs they receive when they purchase renewable fuels. Parties that blend renewable fuel are effectively selling renewable fuel at a lower price than they paid for the renewable fuel.[245] This cost (the difference between the purchase price and the sales price for renewable fuel) is equal to the RIN price. Further, as noted above, analyses by EPA and others have shown that these compliance costs are passed through to consumers in higher prices on the gasoline and diesel subject to the renewable volume obligation (RIN cost passthrough).[246]

In *Sinclair*, the D.C. Circuit found that EPA's denial of SRE petitions was arbitrary and capricious not because RIN cost passthrough does not exist, but because of EPA's reliance on RIN cost passthrough principles that the court found had not been demonstrated to be true for each small refinery in each petition year, making EPA's denials contrary to the record evidence.[247] EPA currently lacks the granular market-level data necessary to precisely evaluate the degree to which a small refiner recovers its RFS compliance costs in each and every market into which it sells transportation fuel. This analysis would require, for example, frequent (*e.g.*, daily) detailed information on the market prices for petroleum blendstocks, renewable fuels, blended fuels, and RINs not only from the small refinery, but also from all other parties selling these products in competition with the small refinery. While pricing information for some of these products is available in many markets, much of this information is not available, particularly for the markets in which small refineries operate.

However, EPA's previous analysis demonstrates that, at least at the national level and in competitive markets, obligated parties are able to recover their compliance costs through the prices they receive for the gasoline and diesel they sell.[248] EPA acknowledges that some national-scale studies have found less-than-perfect RIN passthrough; however, these deviations are relatively small and therefore would be unlikely to lead to a disproportionate cost of compliance

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[242] *Ctr. for Biological Diversity v. EPA*, 141 F.4th 153, 188 (D.C. Cir. 2025) ("*CBD*") (citing *Sinclair*, 114 F.4th at 714 and *Alon Ref. Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 649 (D.C. Cir. 2019) (recognizing that the "central premise – refineries are able to pass RIN costs along to consumers – *is* generally true" (emphasis added)).
[243] Burkholder, Dallas. "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects." EPA, May 2015.
[244] "Denial of Petitions for Rulemaking to Change the RFS Point of Obligation," EPA-420-R-17-008, November 2017.
[245] As an illustration, see Figures 9-12 on pages 17-20 of the Burkholder Study.
[246] 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 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.
[247] *Sinclair*, 114 F.4th at 711–15.
[248] 88 FR 44468 (July 12, 2023). This finding was upheld by the D.C. Circuit in *CBD*.

large enough to constitute a significant economic impact. EPA also recognizes that its previous assessment of complete RIN cost passthrough was premised on the assumption that small refineries can and should purchase RINs ratably, and that parties that choose to delay RIN purchases may pay higher or lower prices for these RINs than they recover when selling the gasoline and diesel they produce. In *Sinclair*, the D.C. Circuit focused on this issue and held that the CAA provides obligated parties flexibility regarding the timing of their RIN purchases and that it was therefore impermissible for EPA to evaluate SRE petitions based on a presumption that small refineries must purchase RINs ratably.[249]

EPA's analysis of the renewable fuel, RIN, and petroleum fuel markets continues to support our previous findings that at the national level and in competitive markets, obligated parties are able to recover their RFS compliance costs (*i.e.,* acquiring RINs) through the prices they receive for the gasoline and diesel they produce. Further, our analysis continues to support our finding that parties that acquire RINs by blending renewable fuels do not acquire these RINs at a lower cost compared to parties that purchase separated RINs, but that these parties instead discount blended fuels sold without a RIN by the value of the RIN.

The commenter cited *West Virginia v. EPA*, a North Dakota district court case that, at the preliminary injunction stage, concluded that EPA could not implement a rule given defects in the regulatory flexibility analysis. We do not find this case to directly apply to this action, where EPA has performed a thorough analysis of the impacts on small entities, and conducted an SBAR panel at the initial implementation of the current iteration of the RFS program in 2010.

With respect to the RIN prices used by EPA under Method 2, commenters provide no data or other support of their claims that EPA's approach purposefully deflates future RIN prices or that that RINs purchased close to the annual RFS compliance deadline are more expensive. EPA has never claimed to have the ability to predict future RIN prices and does not do so in this action. There are myriad factors that affect RIN prices, beyond simply the volume requirements established by EPA in this action. Unpredictable events (*e.g.*, droughts) and factors beyond EPA's control (*e.g.*, global trade policy) have significant impacts on the price and supply of biofuels available in the U.S. and thus also on RIN prices. Lacking the ability to accurately predict what RIN prices will be in 2026 and 2027, we continue to believe that it is reasonable to use average RIN prices over the past 12 months for purposes of the analyses in this action.

Additionally, commenters' claim that small refiners are unable to purchase RINs ratably is not relevant to EPA's analysis under Method 2. We did not assume that obligated parties purchased RINs ratably throughout the year for this analysis. While ratable RIN purchases may be relevant to RIN cost passthrough as described above, Method 2 assumes that RIN cost passthrough *does not exist*. Thus, a small refiner's inability to purchase RINs ratably (to the extent that such inability exists) is not relevant for EPA's analysis under Method 2.

Regarding EPA's choice of the 2025 baseline under Method 2, we first note that the Regulatory Flexibility Act (RFA) does not specify how EPA must choose a baseline or even what type of analysis EPA must conduct to determine whether a SISNOSE exists. The RFA only requires that "an agency may provide either a quantifiable or numerical description of the effects of a

[249] *Sinclair*, 114 F.4th at 709-15.

proposed rule or alternatives to the proposed rule, or more general descriptive statements if quantification is not practicable or reliable."[250] In this final rule, consistent with previous RFS rulemakings, we have chosen to use the standards for the most recent prior compliance year (*i.e.*, 2025) to assess the impacts of this action on small refiners. Commenters misleadingly imply that EPA *only* considered a "No RFS" baseline when assessing the impact of the 2026 and 2027 volume requirements elsewhere in this action. Rather, EPA clearly stated in the Set 2 proposal that "[w]e also consider a 2025 baseline that in some cases may be more informative in understanding the impacts of the Volume Scenarios relative to the status quo."[251] The RFA screening analysis is indeed one such instance in which we believe it is more appropriate to use a 2025 baseline.

As discussed in Preamble Section II, "Congress enacted the RFS program for the purpose of increasing the use of renewable fuel in transportation fuel over time." Thus, for purposes of assessing the incremental impact of the 2026 and 2027 standards on small refiners, we do not believe it would be appropriate to assess the impact of the standards compared to a No RFS baseline (*i.e.*, 0% standards). That impact, as further discussed below, is best addressed through the SRE petition process. Instead, an analysis of the incremental impact on small refiners is more consistent with the assumption that Congress intended for required renewable fuel volumes to increase in the future. While we acknowledge that the RFS standards for one year do not roll over into the next year, they nevertheless represent the most recent set of volume requirements that obligated parties were required to meet and are indicative of the minimum standard with which obligated parties will likely have to comply.

Regarding EPA's use of a cost-to-sales ratio and the 1% economic impact threshold, we continue to believe that these are the appropriate metrics for assessing impacts of the RFS standards rather than a cost-to-profits ratio or a lower economic impact threshold. This approach and threshold is consistent with those used for previous RFS rulemakings and commenters do not provide a compelling or data-supported argument for why we should not use these metrics. While it is true that small refineries submit detailed financial information as part of their SRE petitions, such information is typically limited to the refinery itself.

However, EPA's screening analysis under the RFA considers the financial conditions of this ultimate parent company of the refinery to determine economic impact, not the financial condition of the individual refinery itself, and many small refineries are owned by parent companies that have significant revenue streams from other lines of business within the parent company's portfolio. Thus, the financial information submitted by small refineries in support of their SRE petitions is often not representative or a full picture of the overall financial condition of the parent company. In addition, while we do consider the financial statements from SRE petitions in our analysis, we also gather annual sales data on the ultimate parent company from Hoovers, Inc. Thus, it is not the case that EPA has all "the necessary information to apply a cost-to-profit test" or to "consider the average profit margins of affected small entities" as claimed by the commenters.

[250] 5 U.S.C. § 607.
[251] 90 FR 25809 (June 17, 2025).

Furthermore, even if EPA did possess all the necessary information to conduct a cost-to-profit analysis, we still believe that it is more appropriate to use a cost-to-sales ratio and a 1% economic impacts threshold. Using a sales-based metric for analyzing economic impacts under the RFA instead ensures a consistent basis by which EPA can assess the incremental impact of the RFS standards without having to disentangle exogenous industry factors affecting profitability from any impacts from the RFS program. Again, we reiterate that impacts on an individual small refiner that may justify some form of relief from the refiner's RFS obligations are best and most appropriately addressed through the SRE petition process, not through a RFA screening analysis.

In addition, while commenters claim that 1% of a small refiner's sales may equate to 10% of its EBITDA (earnings before interest, taxes, depreciation, and amortization) and 20% of its profits, they provide no data to substantiate this claim, nor how EPA should specifically use these purported impacts to reduce the 1% economic impact threshold for the cost-to-sales ratio. Commenters only state that EPA should "consider" this information and "accordingly lower the threshold in its cost-to-sales analysis;" they do not provide a threshold—for any metric—that they believe would be appropriate to use for analyzing economic impact. EPA has used a 1% threshold for analyzing economic impacts under the RFA since the inception of the RFS2 program[252] and commenters do not provide sufficient evidence for us to do otherwise in this final rule. Thus, we are not changing our economic impact threshold for the RFA screening analysis.

Commenters also speculate that EPA used sales data from 2023 in its cost-to-sales analysis. We clarify here that we used sales data from 2024 for our screening analysis, as this is the most recent year for which full-year sales data was available at the time of analysis.

Commenters' assertion that EPA must consult with small refiners similarly falls flat. Under the RFA, the requirements to conduct a formal analysis (*i.e.*, IRFA/FRFA) and consultation do not apply if the EPA Administrator "certifies that the rule will not, if promulgated, have a significant economic impact on a substantial number of small entities."[253] The terms "significant economic impact" and "substantial number of small entities" are not analytically defined in the RFA, and thus EPA retains discretion in determining how to apply these terms for each rulemaking. EPA addresses this very issue in its RFA guidance document:

> No bright line exists for determining whether a given set of economic impacts constitutes a SISNOSE. The RFA does not define the terms significant or substantial as they pertain to the extent of economic impact and the number of small entities affected. EPA has not established fixed definitions for the terms, reflecting the practical difficulty of stipulating what would uniformly represent a significant economic impact or a substantial number in every regulatory circumstance.[254]

Thus, EPA has discretion to ultimately determine what constitutes a SISNOSE for each individual rulemaking and is not bound by any pre-determined set of metrics. In this action, we

[252] 75 FR 14862 (March 26, 2010).
[253] 5 U.S.C. § 605(b).
[254] "Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act," November 2006, pp. 25–26.

have described our justification for a no SISNOSE determination in Preamble Section XI.D, RIA Chapter 11, and this document. Thus, the requirements to formally consult with small refiners and develop an IRFA/FRFA do not apply to this action.

All that notwithstanding, it is unclear to EPA what exactly it is that commenters believe the Agency could or should provide small refiners through formal consultation that could not be achieved through the normal notice-and-comment rulemaking process. Even were EPA to find that a SISNOSE may exist for small refiners, the RFA does not grant the Agency any new or additional authority to implement additional flexibilities to small refiners;[255] EPA remains bound by the authorities granted to the Agency under CAA section 211(o) for the RFS program. EPA already considered numerous additional flexibilities for small refiners as part of the RFS2 Rule, most of which were related to granting exemptions or delays to small refiners during the phase-in period of the RFS2 program, which has long since passed. Furthermore, other than the increasing nature of the RFS standards themselves (as intended by Congress), the overall structure of the RFS program has not changed since the RFS2 program was established in 2010; thus, EPA does not see a need to evaluate or consider new flexibilities for 2026 and 2027. If commenters' driving concern is an inability to comply with their 2026 and 2027 RFS obligations, then they could seek an exemption through the SRE petition process discussed below.

If EPA were to accept commenters' premise, the Agency would need to undertake a lengthy process of formally engaging with small refiners through a Small Business Advocacy Review (SBAR) Panel prior to *proposing* the volume requirements *every year*. This is simply not a logical reading of the RFA requirements or logistically feasible for a program like the RFS program that requires setting specific standards through a notice-and-comment rulemaking process for every year. While commenters are correct that the *specific* percentage standards with which obligated parties must comply each year do not roll over from one year to the next, the entire compliance framework of the RFS program has been the same since the inception of the RFS2 program (*i.e.*, obligated parties must acquire and retire sufficient number of RINs to meet their annual cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel RVOs). Absent a significant change to the framework of the RFS program from EPA or Congress, we do not believe that there is a need or requirement for EPA to formally solicit additional compliance flexibilities from small refiners every year through a process entirely separate and apart from the notice-and-comment rulemaking itself simply because the actual percentage standards with which small refiners must comply change from one year to the next. Every year, small refiners are required to retire RINs and submit an annual compliance report demonstrating that they satisfied their RVOs. Nothing about those requirements changes in this final rule, nor have they changed since the inception of the RFS2 program. Notably, commenters fail to identify, in their comments on this rule, any specific new flexibility that they believe would be appropriate for small refiners or to alleviate their perceived burdens. If commenters had provided specific proposals that they believed would reduce the burden of the 2026 and 2027 volume requirements on small refiners, EPA would have considered them during this rulemaking.

Ultimately, we believe that the best and most appropriate way to address commenters' concerns about the impacts of a given year's RFS standards on small refiners is through the SRE petition process. To the extent that acquiring and retiring sufficient RINs to demonstrate compliance

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[255] 5 U.S.C. § 606.

presents a financial hardship to a small refiner—regardless of the SISNOSE determination that EPA makes in an individual RFS rulemaking—the statute provides that small refineries may, "at any time," petition EPA for an exemption from their RFS obligations.[256] Congress specifically provided these provisions for small refineries (which EPA also adopted for small refiners) as the mechanism by which an obligated party can seek relief from its RFS obligations.[257] In fact, since commenters submitted their comments on this action, EPA has granted full or partial relief to small refineries on over 150 SRE petitions for compliance years 2018–2024. EPA has signaled that it anticipates continuing to provide such relief in the future, including for 2026 and 2027. The SRE petition process remains the best avenue for adjudicating the impacts of the RFS standards on an individual small refiner.

Finally, commenters requested that we disclose the names of the small refiners assessed in our screening analysis. We agree with commenters that such public disclosure is appropriate and not subject to CBI claims. Therefore, we have provided the names of the small refiners identified by EPA in the RFA screening analysis. However, we are declining to provide specific, anonymized information about our analysis of each company, as such information could be used to reveal the identity of specific small refiners given the limited number of entities in the analysis. We believe that the example calculations provided in RIA Chapter 11 are sufficient to describe EPA's analysis. Should a specific small refiner wish to review EPA's analysis of that refiner, that entity—and not a trade organization or other intermediary—should reach out to EPA as specified in the *Federal Register* notice of proposed rulemaking.

Comment:

A commenter stated that EPA provided no evidence of Tribal consultation or acknowledgement of Tribal interests under Executive Order 13175.

Response:

Upon announcement of the proposed action and per the *EPA Policy on Consultation with Indian Tribes*,[258] on June 13, 2025, EPA sent out a letter offering government-to-government consultation to all 574 Federally recognized Tribes.[259] While one Tribe responded to provide their written comments, none of the other Tribes we contacted accepted the consultation offer. As described in Preamble Section XI.G, Tribes are not directly impacted by this rule because the RFS program is 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 directly affected only to the extent they produce, purchase, or use regulated fuels.

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[256] As noted earlier, all small refiners exclusively own small refineries.
[257] CAA section 211(o)(9)(B).
[258] Available at https://www.epa.gov/tribal/consultation-tribes.
[259] EPA, "Notice of Consultation Opportunity: EPA's Notice of Proposed Rulemaking - Renewable Fuel Standard program (RFS) Set 2," June 13, 2025.

12.2 Policy Considerations

Comment:

Stakeholders submitted comments on the following topics, as requested by EPA:

- Pathway for the production of renewable jet fuel from corn ethanol, including the use of carbon capture and storage, renewable natural gas for process energy, and low-carbon farming practices.
- The definition of "produced from renewable biomass."
- Amendments to verify imported renewable fuels and track feedstock origins.
- Program enhancements to increase the use of qualifying woody-biomass.
- RFS program modifications to unleash the production of American energy.

Response:

EPA thanks the commenters for their feedback on these important issues and will consider the information submitted as part of any future rulemakings or actions on these topics. EPA did not propose any specific action on these topics in this rulemaking and they are not further addressed in this document.

12.3 Beyond the Scope

Comment:

Commenters addressed numerous additional topics, including but not limited to the following:

- EPA's policy on deciding and implementing SRE petitions.
- Updates to EPA's existing lifecycle analyses (LCA) for purposes of determining which pathways satisfy the statutory emissions reduction criteria for the various renewable fuel categories.
- Adding additional pathways to Table 1 to 40 CFR 80.1426 including but not limited to: naphtha and LPG produced from soybean oil, biofuels produced from carinata oil, biofuels produced from wet mill corn oil, jet fuel produced from RNG, RNG produced from cover crops methanol produced from RNG.
- Improvements to the petition process at 40 CFR 80.1416.
- Changes to the E15 misfueling mitigation plans, including the E15 label.
- Introduction of new mid- and higher-level ethanol blends into the market (*e.g.*, E30).
- Changes to when and many RINs can be separated for renewable jet fuel.

Response:

These comments are beyond the scope of this action and are not otherwise addressed in this document.

Comment:

A commenter said that for purposes of determining which pathways satisfy the statutory emissions reduction criteria for the various renewable fuel categories, EPA should update the LCA estimates for RNG and differentiate the LCA estimates and baseline scenarios for each source of biogas feedstock (*e.g.*, landfill biogas, dairy manure biogas). The commenter also stated EPA should account for book-and-claim low carbon intensity electricity and hydrogen used by biofuel production facilities.

Response:

EPA acknowledges this comment and may consider the submitted information in a potential future rulemaking or action. This comment is beyond the scope of this action and is not otherwise addressed in this document.