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

Response to Comments

United States Environmental Protection Agency

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

Response to Comments

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

NOTICE

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

United States Environmental Protection Agency

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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)
BBD	Biomass-Based Diesel
BIP	Biofuels Infrastructure Partnership
BOB	Gasoline Before Oxygenate Blending
CAA	Clean Air Act
CBI	Confidential Business Information
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CWC	Cellulosic Waiver Credits
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
LCA	Lifecycle Analysis
LCFS	Low Carbon Fuel Standard
LNG	Liquified Natural Gas
Monroe	*Monroe Energy v. EPA*, 750 F.3d 909 (D.C. Cir. 2014)
NO_x	Nitrogen Oxides
OPEC	Organization of the Petroleum Exporting Countries
PM	Particulate Matter
REGS	Renewables Enhancement and Growth Support Rule
RFS	Renewable Fuel Standard
RIA	Regulatory Impact Analysis
RIN	Renewable Identification Number
RVO	Renewable Volume Obligation
SRE	Small Refinery Exemption
STEO	Short-Term Energy Outlook
USDA	U.S. Department of Agriculture
VOC	Volatile Organic Compounds

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[a] Individual comments from the public (and attachments submitted with comments) submitted to Docket No. EPAHQ-OAR-2021-0427 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-2021-0427-0500 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:

Many commenters suggested the importance of the RFS program in supporting the production and use of various types of renewable fuel.

Several commenters suggested RFS is intended to reduce GHG emissions and provide diverse domestic energy resources to promote national security.

Other commenters suggested that the RFS program has not demonstrated the intended goals, and that the policy is "based on flawed estimates."

A commenter suggested that RFS is a key driver for GHG reduction policies, and that this rule should be used to address aviation fuel goals under the SAF Grand Challenge.

Other commenters suggest that EPA's action should go further to support the Administration's climate goals.

Response:

We appreciate comments reflecting on the role of the RFS program to companies and individuals across the United States.

The structure of the statutory RFS program drives lower lifecycle GHG emissions and enhances domestic energy security through increased production and use of renewable fuels. The preamble to the Energy Independence and Security Act of 2007 (EISA), the statute that enacted the current RFS program lists numerous goals: "An Act To move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers …[.]" In exercising the set authority, EPA is required by Congress to consider a list of environmental, economic, and other factors contained in CAA section 211(o)(2)(B)(ii). We believe that our action properly balances these statutory factors in the context of the statute's purposes.

This rule does support the use of sustainable aviation fuels, which is a form of BBD. We address this topic further in RTC Section 6.1.2. However, issues related to aviation fuel goals under the SAF Grand Challenge are beyond the scope of this action.

This action properly advances the Administration's goals within the bounds of the CAA.

Comment:

A commenter suggested that EPA should "return to the original congressional intent of the D3 RIN Cellulosic Waiver Credit: setting high blending mandate goals for cellulosic fuels that are not expected to be met, but will attract strong investment and create jobs, protected by the ability for the EPA to simply sell CWC's".

Response:

It is not clear from the statute or legislative history that the commenter's interpretation of congressional intent is the case. Further, it would seem to be in conflict with the express direction from Congress that the cellulosic volumes established by EPA for years after 2022 be based on the assumption that we would not have to subsequently waive them. Therefore we decline to make changes in this action to achieve such a goal.

Comment:

A commenter suggested EPA lacked the authority to assert "maintaining stable fuel supplies and refining assets" as new goals for the RFS program.

Response:

EPA has the authority to consider topics like maintaining stable fuel supplies and refining assets as we implement the statutory RFS program, particularly as those relate to energy security and independence, which are stated goals of EISA. EPA is also statutorily required to consider, inter alia, "the impact of renewable fuels on the energy security of the United States" and "the impact of renewable fuels on the infrastructure of the Unite States, including the deliverability of materials, goods, and products other than renewable fuel" in setting volumes in years after 2022. CAA section 211(o)(2)(B)(ii).

2. Legal Authorities

2.1 Legal Authorities in this Action

2.1.1 Set Statutory Language and Criteria

Comment:

A commenter suggested that because EPA failed to meet the statutory deadline of "14 months before the first year for which such applicable volumes will apply," EPA cannot set the volumes higher than the volumes finalized for the 2022 standard. The commenter pointed to the D.C. Circuit's *Monroe* decision which upheld EPA's issuance of late standards, but noted that "[o]bligated parties had long been aware of the applicable volumes prescribed in the statute," and that such conditions do not exist for this rulemaking. The commenter suggested that the obligated parties lack notice of the standards.

Response:

While the commenter correctly notes that some of the factual circumstances in *Monroe Energy, LLC v. EPA*, 750 F.3d 909 (D.C. Cir. 2014) are not applicable here, the commenter ignores *Americans for Clean Energy v. EPA*, 864 F.3d 691 (D.C. Cir. 2017) ("*ACE*"), where the factual circumstances align more closely with this rule. In *ACE*, the court evaluated our late and retroactive promulgation of the BBD standards for 2014 and 2015, and late promulgation of the 2016 and 2017 BBD standards. Similar to the volumes we are setting in this final action, the BBD volumes for 2014-2017 did not have prescribed volumes in the statutory tables at CAA section 211(o)(2)(i). Rather, EPA used the authority in CAA section 211(o)(2)(B)(ii) to establish BBD volumes for those years. First, the *ACE* court found that EPA retained authority to promulgate late volumes under its authority in CAA section 211(o)(2)(B)(ii). *ACE* at 720. Next, the *ACE* court upheld the late BBD volumes for 2016-2017 and the late and retroactive BBD volumes for 2014-15. *Id.* at 723. Petitioners in that case argued that EPA could not set the late BBD volume above the statutory floor of 1.0 billion gallons, or in the alternative, the 2013 volume requirement of 1.28 billion gallons. *Id.* at 720. The court rejected those arguments for the 2016 and 2017 standards, for which EPA had proposed BBD volumes at 1.8 and 1.9 billion gallons respectively, and finalized volumes at 1.9 and 2.0 billion gallons, pointing to the notice provided by the proposed rule in 2015 and the lead time provided to acquire necessary RINs. The court also disagreed with petitioner's arguments as to the 2014 and 2015 standards, which were retroactive and late. There, EPA set the applicable BBD volume requirements at the volumes of renewable fuel used for those years, which the court found to be reasonable after considering EPA's explanation as to why the standards could nonetheless be met.

As described in Preamble Section II.E, we have considered similar factors in setting the late and partly retroactive 2023 standards, and the late 2024 standards, and find that the standards are reasonable for the reasons described there. We disagree that obligated parties lack adequate notice for the reasons articulated in Preamble Section II.E, and also note that we have looked at renewable fuel generation thus far in 2023 and find that the market is on track to meet the standards, as described further in RIA Chapter 6.2.5 and Preamble Section VI.

Comment:

A commenter suggested that EPA's approach to the conventional volumes is "contrary to the intent of Congress that directed EPA to ensure a minimum percentage of advanced biofuels when it implements the RFS Set criteria," citing to CAA section 211(o)(2)(B)(iii).

Response:

As discussed in Preamble Section II, CAA section 211(o)(2)(B)(iii) requires only that the ratio of advanced biofuel to total renewable fuel remain at or above the advanced/total ratio for 2022. The advanced/total ratios in 2023 (0.284), 2024 (0.304), and 2025 (0.328) are all greater than the advanced/total ratio for 2022 (0.273), and therefore we have complied with this statutory requirement for 2023–2025. CAA section 211(o)(2)(B)(iii) requires nothing more.

Comment:

A commenter suggested that EPA needed to articulate how it weighed the statutory factors. Several commenters suggested that the statute did require particular weighting of certain factors.

Response:

As we explain in Preamble Section II.A, the statute does not indicate that EPA must weigh any specific factors in CAA section 211(o)(2)(B)(ii)(I)-(VI) more than the others. Rather, the statute requires EPA to consider all of the factors but entrusted the proper weighing of the factors to the Administrator's judgment. As we explain in Preamble Sections II and III and the RIA, EPA has engaged in a holistic balancing of the factors in determining the final volumes.

Comment:

A commenter suggested that EPA has failed to consider all relevant statutory factors and particularly points to the impact of the production and use of renewable fuels on the environment, the cost to consumers of transportation fuel and on the cost to transport goods, and on job creation. The commenter then points to analysis of these factors that may support lower volumes.

Response:

We respond to the commenters' assertions on these topics in RTC Section 9.

Comment:

A commenter suggested that EPA is interpreting CAA section 211(o)(2)(B)(ii) and (iv) of the CAA too conservatively, and that EPA should instead set "robust volumes for cellulosic biofuels without building in an ex-ante expectation that EPA will need to use its cellulosic waiver authority." The commenter suggests that doing so would support expansion of renewable fuel production and use, and that the cellulosic volumes should "reflect[] expected actual output."

Response:

The cellulosic biofuel volumes we are finalizing in this action do reflect expected actual output and growth in the cellulosic biofuel volumes. This approach properly harmonizes our consideration of the Set factors with the statutory requirement that we must set volumes such that the Administrator shall not need to issue a waiver under CAA section 211(o)(7)(D). The resulting volumes are discussed further in RTC Section 3.

Comment:

A commenter suggested that EPA must articulate an "objective repeatable methodology describing how it is applying the statutory criteria to each annual renewable fuel standard." The commenter asserts that because EPA only quantified and monetized two of the statutory criteria, EPA's "analysis and application of the[] factors are inadequate." The commenter also suggested that EPA's qualitative assessment is insufficient.

Response:

We disagree with the commenter that the statute requires EPA to articulate a repeatable methodology, and the commenter does not explain what such a methodology would entail. The statute only requires that EPA "determine[]" the applicable volumes "based on a review of the implementation of the program . . . and an analysis of [the statutory factors]." CAA section 211(o)(2)(B)(ii). We have explained our determination in Preamble Section VI. The statute does not require quantitative or monetized assessment of the statutory criteria. As we explain in Preamble Section IV.D and the RIA, EPA was not able to quantify and monetize the other factors in the timeframe of this rule. The commenter has failed to articulate with reasonable specificity how EPA's qualitative assessment was insufficient. In any event, EPA has explained how it analyzed each factor, including in the preamble, RIA, and RTC document.

Comment:

A commenter suggested, based on statements in the congressional record, that CAA section 211(o)(2)(B)(ii) "directs the administrator to set the mandate at a level that the administrator expects *can be met* without the use of the safety net provisions in . . . Section 211(o)(7)(D)." The commenter then suggested that this means EPA must set the maximum achievable targets after reviewing the statutory factors.

The commenter further suggested that CAA section 211(o)(2)(B)(iv) may not even apply to volumes after 2022 because CAA section 211(o)(7)(D), the cellulosic waiver authority, refers to projections from EIA that are only provided through 2021. The commenter suggests instead that CAA section 211(o)(2)(B)(iv) applies when EPA modifies volumes utilizing the reset authority, under CAA section 211(o)(7)(F).

The commenter suggested that EPA's interpretation of CAA section 211(o)(2)(B)(iv) is in conflict with the statutory criteria EPA is to consider under CAA section 211(o)(2)(B)(i), such as the annual rate of future commercial production.

The commenter urges EPA to set the volume based on a review of all of the factors listed, and be ambitious in setting the cellulosic volumes.

Response:

While contemporaneous statements made at the time a law is enacted can be illuminating, we must begin our assessment with the statutory text which provides that EPA is to set the applicable cellulosic biofuel volume based on an analysis of enumerated factors and "based on the assumption that the Administrator will not need to issue a waiver for such years under [CAA section 211(o)](7)(D)." CAA section 211(o)(2)(B)(ii) & (iv). Notably, the phrase emphasized by the commenter, "can be met," does not appear in the statute. Nor does the statute direct EPA to establish "maximum achievable targets." In any event, as we explain in Preamble Section VI.A, EPA has established the cellulosic biofuel volume at levels that that reflect the full growth potential of the cellulosic biofuel industry.

We recognize that CAA section 211(o)(7)(D) refers to projections from the Energy Information Administration (EIA) to be provided to EPA through 2021, but CAA section 211(o)(7)(D) provides EPA the authority to reduce the cellulosic biofuel volume in "[CAA section 211(o)](2)(B)", which includes both the statutory volumes in CAA section 211(o)(2)(B)(i) and volumes set under CAA section 211(o)(2)(B)(ii). The commenter also recognizes this reading, suggesting that the "cellulosic waiver provision should be applied in a similar manner it did pre-2023." Moreover, while EPA acknowledges the commenter's contextual argument, the statutory text at CAA section 211(o)(2)(B)(iv) is clear that it applies to situations where EPA sets the RFS volumes under CAA section 211(o)(2)(ii). By its own terms, clause (iv) applies "[f]or the purpose of making the determinations in clause (ii), for each calendar year."[1]

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. We find that it is possible to read the various statutory provisions relating to EPA's action in setting the applicable volumes for years beyond those provided in the statutory tables cohesively, such that we provide meaning to each of the statutory requirements. Our final rule properly gives meaning to each of the provisions—we have assessed each of the statutory factors with respect to cellulosic biofuel, including "expected annual rate of future commercial production", and have set cellulosic volumes at levels that are not so ambitious that we believe we will need to waive the volumes in the future under the cellulosic waiver authority. We further address comments to the cellulosic volume in RTC Section 3.

[1] CAA section 211(o)(2)(B)(iv), in contrast, does not apply when EPA exercises its reset authority under CAA section 211(o)(7)(F).

2.1.2 Other Statutory Authority

Comment:

One commenter stated that requiring feedstock providers to register with EPA is inconsistent with the statute and unreasonable. The commenter elaborates: "The statute grants EPA authority to establish compliance provisions applicable to refineries, blenders, distributors, and importers, as appropriate, to ensure that the requirements of this paragraph are met, not feedstock providers. 42 U.S.C. § 7545(o)(2)(A)(iii). EPA's proposal here would be a substantial expansion of its authority and a substantial expansion of the RFS regulatory program, creating significant additional administrative burdens that can result in further delays in seeking assistance or approvals from EPA.

In addition, EPA cannot rely on its general rulemaking authority in 42 U.S.C. § 7601. The D.C. Circuit has found that "EPA's authority to issue ancillary regulations is not open-ended, particularly when there is statutory language on point." NRDC v. EPA, 749 F.3d 1055, 1063 (D.C. Cir. 2014) (citations omitted). Moreover, requiring the landfill, wastewater treatment plant, or digester owner to register under the RFS may prove impossible. For such owners, their business is collecting and disposing of trash, or cleaning wastewater, or farming – and the RNG production facilities located at their site are a very small consideration. The site owner is unlikely to agree to register and accept liability under the RFS, particularly when they have no control or insight into the downstream sale of the RNG product by the RNG producer."

Another commenter said that requiring cellulosic biofuel feedstock suppliers to register under the RFS is outside of EPA's statutory authority. Expanding these requirements will limit participation in the RFS and hamper growth within the category.

Response:

While CAA section 211(o)(2)(A)(iii) is one source of EPA's authority to promulgate compliance obligations for particular parties, the commenter ignores CAA section 211(o)(2)(A)(i) which provides that EPA shall "promulgate" and "revise" "regulations . . . to ensure that transportation fuel sold or introduce into commerce … contains at least the applicable volume" of renewable fuel. By putting in place requirements for feedstock providers akin to the requirements for renewable fuel producers—who have been regulated entities under the program since its inception (e.g., renewable fuel producers, importers, RIN generators for biogas, etc.)—we are ensuring that feedstocks meet the statutory criteria to qualify as renewable biomass and that, in turn, the fuel produced and used to satisfy the statutory volume requirements is actually renewable fuel. This final rule is under this authority to promulgate regulations for the RFS program in CAA section 211(o)(2)(A)(i), in addition to the EPA's general rulemaking authority pursuant to CAA section 301. The commenter is therefore mistaken in claiming that EPA is solely or otherwise erroneously relying on CAA section 301 to promulgate this rulemaking. We also note that RNG producers, RNG importers, marketers, and third parties that manage environmental commodities currently make up a bulk of the parties registered to generate RINs under the previous biogas provisions; requiring such parties to register in order to participate in the RFS is not a new phenomenon.

Furthermore, feedstock providers' participation in the RFS program is completely voluntary, and the commenter's suggestion that we are imposing mandatory obligations on feedstock suppliers is false. In the specific case of biogas regulatory reform, the feedstock suppliers that the commenter is referring to are biogas producers (e.g., landfills, wastewater treatment plants, or digester owners). Under the existing biogas provisions, biogas producers may voluntarily subject themselves to the RFS program directly, by registering to generate RINs, or indirectly, by supplying biogas to RIN generators under the existing program. The same is true under the biogas regulatory reform provisions. The biogas producer can generate RINs in a biogas closed distribution system or supply biogas to an RNG producer. The only difference is that instead of supplying registration information related to their biogas production facility to a RIN generator that in turn supplied to EPA, the biogas producer will supply that information directly to EPA.

We also note that under the biogas regulatory reform provisions it is not necessarily, for example, the municipality that owns the landfill or wastewater treatment plant or the farmer that supplies agricultural wastes who must register. That is, we are not mandating that municipalities or farmers register under the RFS program as suggested by the commenter. Under the definition of biogas producer as part of this final action, the biogas producer is any person that "owns, leases, operates, controls, or supervises a biogas production facility." See 40 CFR 80.2. While the commenter's examples assume the landfill, wastewater treatment plant, or farmer owns the facility and would necessarily be the party that registers under the RFS, this is incorrect. There may be other parties that lease, operate, control, or supervise the facility; any party that fills one of these defined roles may register the biogas production facility under the RFS program. Because of the broad definition of biogas producer, we expect that only those municipalities and farmers that find it in their economic interest to do so will register to participate in the RFS program. As discussed in Preamble Section IX.C, we believe these parties are likely to engage with other parties that fit the definition of biogas producer and/or with third parties that will help them meet their regulatory requirements.

For these reasons, EPA does not agree that the final rule entails a substantial expansion of our authority or of the RFS regulatory program, will result in significant new administrative burdens, or will limit participation in RFS or hamper growth in cellulosic biofuel volumes.

We discuss biogas regulatory reform in more detail in Preamble Section IX and RTC Section 10.

2.2 Waiver Authorities

Comment:

Commenters suggested that EPA should establish objective parameters that would trigger a waiver under the cellulosic waiver authority given the length of time necessary to waive volumes through the notice and comment process. Commenters suggested that doing so would increase market certainty and prevent volatility in RIN prices. Other commenters suggested that EPA should continue to make CWCs available if, in the future, EPA utilizes the cellulosic waiver authority.

Response:

As stated in the proposed rule, we maintain the view that our waiver authorities remain available as applied to the volumes set in this action. And should EPA in the future waive the cellulosic volumes under CAA section 211(o)(7)(D), EPA would make cellulosic waiver credits available, consistent with the statute. Aside from what already exists in the statute, we decline at this time to put forth additional criteria under which we might waive the cellulosic volumes, as the need to waive volumes is likely to be a function of the specifics of the situation. Nevertheless, should there be a significant shortfall in the cellulosic biofuel market, we would assess the situation to determine whether the use of the cellulosic waiver authority would be appropriate.

Comment:

A commenter suggested that EPA should still make CWCs available even without exercising the cellulosic waiver authority under CAA section 211(o)(7)(D). The commenters pointed to obligated parties' reliance on CWCs as a compliance mechanism, and its role as a price cap for D3 and D7 RINs. The commenter suggested that the CWCs will provide obligated parties with compliance certainty. The commenter also suggested that making CWCs available would reduce the need for a waiver of the cellulosic volumes under CAA section 211(o)(7)(D), consistent with CAA section 211(o)(2)(B)(iv). Commenters noted that there is no explicit statutory prohibition on making CWCs available, and that EPA has in the past claimed broad discretion to govern the RFS credit market. The commenter also suggested that EPA could utilize CAA section 211(o)(7)(D)(iii), which authorizes EPA to promulgate regulations associated with the issuance of CWCs.

Response:

While we recognize the historic role of cellulosic waiver credits (CWCs) in the program as both a price cap and a compliance mechanism, we disagree with the commenter's suggestion we can issue CWCs without a corresponding waiver of the cellulosic biofuel volume under CAA section 211(o)(7)(D) for the reasons described in the Preamble Section II. We will continue to monitor the compliance with the cellulosic biofuel standards and if necessary exercise our cellulosic waiver authority which would then make CWCs available.

To respond further to the arguments presented by the commenter, we do not read CAA section 211(o)(2)(B)(iv) to allow EPA to issue waiver credits. The statute does not explicitly provide EPA with authority to issue CWCs in CAA section 211(o)(2)(B)(iv). Rather, CAA section 211(o)(2)(B)(iv) provides a criterion for how EPA should determine the cellulosic biofuel volume in years after 2022, in addition to the factors in CAA section 211(o)(2)(B)(ii). While the statute does not explicitly prohibit the issuance of CWCs in circumstances other than those articulated in CAA section 211(o)(7)(D), the statute's explicit direction in CAA section 211(o)(7)(D) suggests that Congress did not intend for EPA to have the authority to issue CWCs in other circumstances. We agree with the commenter we have broad discretion to govern the RFS credit market, but we do not find we have authority to issue CWCs in this rule because we are not exercising the cellulosic waiver authority. While CAA section 211(o)(7)(D)(iii) authorizes EPA to promulgate regulations associated with governing the issuance of CWCs, we do not read this provision as granting additional authority to issue CWCs in the absence of a waiver under CAA section 211(o)(7)(D). Additionally CAA section 211(o)(7)(D)(iii) expressly contemplates that regulation promulgated under that authority would apply "*in the event of a waiver*." Our regulations at 40 CFR 80.1456(a) and (b) also expressly contemplate CWC availability only "[i]f EPA reduces the applicable volume of cellulosic biofuel."

2.3 Carryover RINs

2.3.1 General Consideration 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 2023–2025 volume requirements. These commenters were generally obligated parties and reiterated the importance of maintaining the availability of carryover RINs in order to provide obligated parties with necessary compliance flexibilities, better market trading liquidity, and a cushion against future program uncertainty. Several commenters also stated that the proposed volume requirements would drain an already-diminished supply of carryover RINs.

Conversely, several other commenters stated that EPA should intentionally draw down the number of available carryover RINs. These commenters were generally renewable fuel producers and stated that settings volume requirements without regard to the number of available carryover RINs goes against Congressional intent of the RFS program and reduces demand, development, and consumption of renewable fuels, thereby suppressing RIN prices. These commenters argue that high RIN prices are how the RFS program achieves its goal of increasing use of renewable fuels.

Response:

EPA has carefully considered these comments and is establishing the 2023–2025 standards at levels that are not expected to intentionally draw down the number of available carryover RINs. 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 2023–2025, 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.C.4 (including the significant decrease in the number of available carryover RINs), we have determined that it is appropriate for EPA to set the volume requirements for 2023–2025 without the express intention or expectation of a drawdown in the number of available carryover RINs.

As explained in Preamble Section III.C.4, we believe it is appropriate for EPA to not intentionally draw down the number of available carryover RINs in setting the 2023–2025 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.[2]

In standard-setting rulemakings, we have assessed the availability of carryover RINs on a case-by-case 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.[3] 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 2023–2025 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,[4] in which it is commonly understood that a reserve fund should be maintained to cover unforeseen circumstances.[5] 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

[2] See also *Growth Energy v. Env't Prot. Agency*, 5 F.4th 1, 18 (D.C. Cir. 2021); *Am. Fuel & Petrochemical Manufacturers v. Env't Prot. Agency*, 937 F.3d 559, 583 (D.C. Cir. 2019).
[3] 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).
[4] See 80 FR 77483-84 (December 14, 2015).
[5] 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 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.

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.C.4, 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 2023–2025 cellulosic biofuel, biomass-based diesel, 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.[6] Moreover, as explained in RIA Chapter 5, we believe that the final 2023–2025 volumes 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 standards in this manner should not result in a drawdown in the number of available carryover RINs. However, 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 2023–2025. 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 well over $1 per RIN and are indeed incentivizing additional renewable fuel use, consistent with Congress' intent.[7] 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 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 2023–2025, we expect significant increases in renewable fuel use, particularly from renewable

[6] As described further in RTC Sections 3 and 6, we are setting the cellulosic biofuel applicable volumes at levels of projected growth based on the available data, cognizant of the statutory requirements of CAA section 211(o)(2)(B)(iv).

[7] For more information on RIN prices and the current number of available carryover RINs, see RIA Chapters 1.9 and 1.10.

diesel and biogas, much of which are enabled by newly constructed or converted biofuel production facilities.[8] Indeed, during the first quarter of 2023, we have observed significant increases in renewable fuel use, as we describe further in RTC Section 6.1.4. See also RIA Chapters 3.2 and 3.3, where we show that the volume requirements we are establishing for 2023–2025 represent increases in comparison to actual consumption in 2022 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.C.4, 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.

[8] 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 6.

2.3.2 Consideration of Cellulosic Carryover RINs and Accounting for RIN Surpluses

Comment:

Multiple commenters stated that EPA should adopt an automatic adjustment mechanism to prevent a situation where cellulosic RIN generation in excess of the required volume would result in reduced RIN prices. These parties generally argued that EPA's proposal to establish volumes for three years in the Set rule, together with the proposed eRIN provisions and the rapidly evolving cellulosic biofuel market, significantly increased the possibility that cellulosic biofuel production could exceed the required volumes. These commenters generally stated that lower cellulosic RIN prices would decrease investment in cellulosic biofuel production, and some stated that even the potential risk that excess RIN production could result in lower RIN prices in the future could negatively impact investment.

A few parties offered more detailed suggestions for how such an automatic adjustment mechanism could work. While not all the suggestions were identical, they generally included EPA's adoption of a formula that would be used to automatically adjust (increase or decrease) the required volume of cellulosic biofuel in a future year based on actual or projected cellulosic biofuel surpluses (or deficits) that would be carried into the next year. Some of these commenters included a discussion of EPA's statutory authority to adopt such a mechanism. At least one commenter stated that an adjustment mechanism was necessary for EPA to meet their statutory obligation to "ensure that the volumes are met."

Conversely, multiple commenters opposed the adoption of a mechanism to automatically adjust the required volumes to match cellulosic biofuel production. Some of these commenters stated that such a mechanism would be legally risky. One commenter stated that revising the cellulosic volumes to the actual level of production would indicate that the volumes in the Set rule are not binding and would cast doubt over the volumes finalized in the Set rule. They stated that the adoption of any adjustment mechanism would moot the need to set prospective standards at all. Finally, the commenter noted that unlike volume reductions using the cellulosic waiver authority, any revisions to increase the cellulosic biofuel volume would have to be based on a review of the statutory factors, not just cellulosic biofuel production. Another commenter similarly stated that any automatic adjustment mechanism would violate the statutory requirements that the required volumes be set 14 months in advance, the requirement that the volumes be based on the statutory criteria, and a desire that the RFS volume requirements be forward looking.

Response:

A discussion of our consideration of a mechanism that would automatically adjust the required volume of cellulosic biofuel based on the number of cellulosic RINs generated each year relative to the required volume can be found in Preamble Section VI.A. We do not agree that the text of the Energy Independence and Security Act, the Clean Air Act, 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.

EPA agrees that we have a statutory obligation to "ensure" that the volumes be met. CAA section 211(o)(2)(A)(i). EPA has done so through this rulemaking, including by promulgating percentage standards that ensure the volumes we are setting for 2023-25 are met. Nothing in this provision, however, suggests that EPA must retroactively adjust the volumes based on actual use of renewable fuel during the calendar year.

Since EPA is not adopting any automatic adjustment mechanism, we need not resolve whether any such mechanism would be precluded by the statute. However, we acknowledge commenters' concerns that such a mechanism appears potentially incongruent with the prospective nature of the volume-setting framework, including specifically the 14 month lead-time requirement in CAA section 211(o)(2)(B)(ii). Cf. 87 FR 39632/2 & n.187 (citing 77 FR 1340).

More generally, we do not agree that eliminating risk for investment in cellulosic biofuel growth must be the overriding consideration in establishing cellulosic biofuel volumes. The statute requires that EPA consider many different factors, including, inter alia, the "cost to consumers," when establishing cellulosic volumes for 2023 and beyond. CAA section 211(o)(2)(B)(ii)(V). For a more detailed consideration of the consideration of cellulosic carryover RINs when EPA exercises our cellulosic waiver authority see Chapter 2.6.2 of the Response to Comment document for the 2020–2022 RFS rule.

Comment:

Multiple commenters stated that adopting an automatic adjustment mechanism would not increase the costs or fuel price impacts relative to those projected in the proposed rule. These parties stated that the RIN price EPA used in the fuel price impact calculations (approximately $3 per RIN) was already near the price ceiling for cellulosic RINs, which is set by the price of the cellulosic waiver credit.

Response:

Our overall societal cost assessments for the final rule, discussed in greater detail in RIA Chapter 10, are based on the cost to produce renewable fuels relative to the cost to produce the petroleum fuels they displace. RIN prices do not factor into our cost analyses. Therefore, were EPA to adopt an automatic adjustment mechanism its impact on the projected societal cost of this rule would only occur to the degree that such a mechanism also impacted the required volumes of cellulosic biofuel in 2023–2025.

However, this does not mean that higher RIN prices would not impact fuel prices to consumers. We expect that adopting an automatic adjustment mechanism, as the commenter request, would increase the likelihood of high cellulosic RIN prices. Our estimates in RIA Chapter 10.5 of the impact of this rule on fuel prices are roughly 2-4 c/gal for gasoline and 10-11 c/gal for diesel fuel over the 2023–2025 period. These fuel price impacts consider the impact of RIN prices on gasoline and diesel. The cost of acquiring cellulosic RINs is expected to account for approximately 1-2 c/gallon of the total price impact on gasoline and diesel in 2023–2025 (see RIA Chapter 1.9.2). In this context we projected RIN prices for each category of RIN at the average RIN price observed in the past 12 months for which data are available ($2.79 per RIN, based on data from May 2022 – April 2023).

The commenters' claims that the RIN price used in the proposed rule to project the impact on fuel prices is near the price ceiling for cellulosic RINs is not accurate. These claims appear to assume that the maximum cellulosic RIN price is established by the price of the cellulosic waiver credit each year. But this ignores the fact cellulosic waiver credits are only made available to obligated parties when EPA exercises our cellulosic waiver authority. We are not exercising our cellulosic waiver authority in this final rule, and while we retain the ability to exercise the cellulosic waiver authority in future years if the statutory conditions are met there is no guarantee that we will use the cellulosic waiver authority in any future year. Indeed, following the statutory mandate, we have set the cellulosic biofuel volume on the assumption that we will not be exercising the cellulosic waiver authority. Unless and until we use the cellulosic waiver authority to reduce the required volumes of cellulosic biofuel cellulosic waiver credits will not be available and there will be no real or effective price ceiling for cellulosic biofuel RINs. Further, cellulosic waiver credits only satisfy an obligated party's cellulosic biofuel obligation. Obligated parties that purchase cellulosic waiver credits still need to purchase an advanced RIN to meet their advanced biofuel and total renewable fuel obligations. The price ceiling for a cellulosic RIN is therefore not simply a function of the cellulosic waiver credit price, but also of the price of advanced biofuel RINs. Finally, we note that even if the price for cellulosic RINs do not rise above the level we used in our analyses in the proposed rule (approximately $3 per RIN) we would expect a non-trivial impact (i.e., 1–2¢ per gallon) on gasoline and diesel prices from the cellulosic biofuel volumes in this final rule.

Comment:

A commenter stated that when reducing the cellulosic biofuel volume using the cellulosic waiver authority the "projected volume available" at which EPA is required to set the cellulosic biofuel volume must include any available carryover RINs from previous years.

Response:

This comment is beyond the scope of the rule since EPA is not using the cellulosic waiver authority in this rule. EPA previously addressed this issue in the context of the 2020-2022 RFS annual rules, primarily in Section 2.6.2 of the RTC document for that rule. We further note that, as discussed in RIA Chapter 1.11, we do not project there will be an appreciable quantity of carryover cellulosic RINs available for use in 2023.

3. Cellulosic Biofuel

3.1 General Comments on Cellulosic Biofuels

Several comments in this section address our projections of eRINs in the proposed rule and/or the potential impact of the incentives provided by eRINs. However, we have not addressed these comments because we are not taking a final action on the proposed eRIN provisions.

Comment:

Multiple commenters stated that the projected volumes of cellulosic biofuel production and imports should be higher. As evidence that the projected volumes are too low one commenter referred to projections of CNG/LNG production from the Coalition for Renewable Natural Gas that exceed EPA's projections and the fact that D3 RINs were trading at a small premium to D5 RINs. Some of these commenters mentioned specific types of cellulosic biofuel the believed would exceed EPA's projections (ethanol from corn kernel fiber, CNG/LNG, eRINs, etc.).

Similarly multiple commenters stated that EPA should establish higher cellulosic biofuel volumes using a less conservative approach to projecting cellulosic biofuel production to support higher and/or more stable cellulosic RIN prices and greater support for cellulosic biofuel production. One commenter specifically stated that the failure to do so would result in an over-supply of cellulosic RINs and lower RIN prices, while another commenter stated that D3 RIN prices have been falling steadily since the proposed volumes were released, indicating an over-supply of D3 RINs. Another commenter similarly stated that the cellulosic volumes should be set in a way that ensures that the cellulosic RINs always trade at the sum of the cellulosic waiver credit and the advanced biofuel RIN price. This commenter stated that this would provide consistent incentives for cellulosic biofuel production and would allow OEMs to pass through the RIN value to consumers in a way that would not be possible if cellulosic RIN prices are volatile.

Response:

Responses to comments related to our projections of liquid cellulosic biofuel and RNG used as CNG/LNG are covered in RTC Sections 3.2.1 and 3.2.2.

The volumes we are finalizing in this rule are considerably higher than those projected at proposal, accounting for the fact that we are not finalizing eRINs in this final rule. They are based on our assessment of the statutory factors; we have not tried to establish volumes that would achieve a particular RIN price as EPA does not view achieving a particular RIN price as a relevant factor in setting the volumes under EPA's "set" authority. However, the fact that cellulosic RINs are currently trading at a premium to advanced biofuel RINs indicates that the market does not anticipate a surplus of cellulosic biofuel RINs (beyond the carryover limits). If the market did anticipate a surplus of cellulosic RINs, we would expect that cellulosic RINs and advanced biofuel RINs would trade for approximately the same price. While cellulosic RIN prices are generally lower in 2023 than in 2022, according to EMTS data they are still averaging over $2 per RIN, which provides a significant incentive for the production and use of cellulosic biofuel. Fluctuations in RIN prices are a normal part of a competitive market and are inherent in the system Congress directed EPA to establish in EISA wherein EPA requires the use of particular types of renewable fuel rather than providing a consistent per-gallon incentive as with most tax credits. Further, despite the fluctuations in cellulosic RIN prices observed in recent years cellulosic biofuel production has increased at an average rate of 25% year over year since 2015.

Comment:

Multiple commenters stated that if EPA did not account for all potential sources of cellulosic biofuel there could be an over-supply of cellulosic RINs. This over-supply of cellulosic RINs could negatively impact the price of D4, D5, and D6 RINs.

Response:

As discussed in greater detail in RIA Chapter 6.1, our projection of the projected volume available considers all potential sources of cellulosic biofuel we believe will be produced or imported and available for use in the U.S. as transportation fuel through 2023–2025. In situations where commenters identified potential sources of cellulosic biofuel not considered by EPA we evaluated these potential sources and included them in our projected volumes for this final rule as appropriate. This includes volume from newly approved pathways and from facilities that have not yet completed the registration process but are expected to do so on a timeline that would allow them to generate an appreciable number of cellulosic RINs by 2025. Given the uncertainty inherent in projecting volumes into the future, it is possible that the market will produce more or less cellulosic biofuel than EPA projects. For example, while it is possible that a facility not projected by EPA to produce cellulosic biofuel by 2025 will do so, since we cannot anticipate every possible future scenario, we do not expect that this would result in an over-supply of D3 RINs to such a magnitude that there would be an impact on the price of D3 RINs or the prices of other types of RINs (D4, D5, or D6).

Comment:

Multiple commenters stated that the cellulosic biofuel volumes should be set at the maximum achievable levels or should reflect the full potential of the cellulosic biofuel industry and should include consideration of all potential cellulosic biofuels. One commenter similarly stated that EPA is not bound to establish the cellulosic volumes at the projected level using a neutral aim at accuracy in the Set rule and should instead establish the volumes at the highest levels achievable that will not trigger the cellulosic waiver authority.

One commenter acknowledged that EPA must set cellulosic volumes assuming that no waiver will be needed to reduce these volumes in the future but stated that this does not mean EPA is required to set overly conservative volumes.

Response:

As discussed in Preamble Section VI.A, we are finalizing cellulosic biofuel volumes that reflect the projected growth in cellulosic biofuel production from 2023–2025 in light of the incentives available to cellulosic biofuel producers from the RFS program and other state and federal programs, and in light of our consideration of the statutory factors based on the available data. The projection methodology used in this rule does not result in overly conservative projections, nor does it result in projections of cellulosic biofuel production that are expected to be realized without the incentives provided by the RFS program.

The statutory requirements for establishing cellulosic volumes for years beyond 2022 in CAA section 211(o)(2)(B)(ii) & (iv) are not identical to the criteria for exercising the cellulosic waiver authority in CAA section 211(o)(7)(D). After 2022, cellulosic volumes are to be promulgated 14 months in advance, considering the enumerated factors, and are to be "based on the assumption that the Administrator will not need to issue" a cellulosic waiver. The cellulosic waiver authority, on the other hand, is a reduction of the cellulosic volume required by the statute when the projected volume of cellulosic biofuel production—based on an EIA estimate provided to EPA (through 2021) by November 30 of the previous calendar year—is less than the cellulosic volume otherwise required by the statute. The D.C. Circuit has directed EPA to take a "neutral aim at accuracy" in projecting the cellulosic volume under the cellulosic waiver authority. *American Petroleum Institute (API) v. EPA*, 706 F.3d 474, 479 (D.C. Cir. 2013). 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 3 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.

Regardless, 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." *API vs. EPA*, 706 F.3d at 479. 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, *API v. EPA*, 706 F.3d at 428, 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. 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, *see ACE*, 864 F.3d at 691, 724, 726-729. Moreover, the general approach to projecting the cellulosic biofuel volume (e.g., conducting an industry-wide assessment for biogas and identifying the projected growth rate based on historical data) is consistent with that used in recent RFS rules.

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 waive these volumes. We further address comments on our methodology for projecting cellulosic production and use in years 2023–2025 in RTC Section 3.2.

Comment:

Multiple commenters stated that EPA should establish the cellulosic biofuel volumes one year at a time (rather than establishing volumes for three years in the Set rule) to better ensure that the cellulosic biofuel volumes are set at a level certain to drive growth in cellulosic biofuels and support investment. One commenter stated that there was too much uncertainty in cellulosic biofuel production through 2025 to establish cellulosic biofuel volume requirements in this rule. Another commenter similarly stated that EPA should revisit the cellulosic volumes for 2024 and 2025 when more data are available.

Response:

A discussion of our decision to finalize RFS volume requirements for three years in this rule can be found in Preamble Section II.D, and comments on this topic are discussed in RTC Section 6.2.3. We do not believe that the uncertainty associated with the projections of cellulosic biofuel production is categorically different than the uncertainty associated with the projections of the production and use of other types of biofuels such that the reasons presented elsewhere in this rule do not apply to cellulosic biofuel. Although we do not anticipate needing to waive volumes in the future, if the cellulosic biofuel volumes we are establishing in this rule for 2024 and 2025 are significantly lower or higher than the actual production and import of cellulosic biofuels in these years based on circumstances we have not and cannot anticipate, we retain our statutory authorities to adjust these volumes as appropriate.

Comment:

A commenter stated that EPA should be cautious in its projections of cellulosic biofuel production, especially since cellulosic waiver credits will not be available to obligated parties in 2023. This commenter noted that cellulosic biofuel is a small enough percentage of the advanced biofuel and total renewable fuel volume requirements that excess cellulosic RIN generation would not impact the price of other RIN types. They further stated that CNG/LNG and electricity produced from biogas would be used even in the absence of incentives from the RFS program, so these fuel types would not be negatively impacted by lower cellulosic RIN prices.

Response:

As discussed in Preamble Section VI, we find that the benefits of higher volumes of cellulosic biofuel outweigh the potential negative impacts. We therefore believe that to realize the benefits associated with increasing cellulosic biofuel production it is reasonable to establish cellulosic biofuel volume requirements through 2025 at the levels that reflect the projected growth in cellulosic biofuel production from 2023–2025 based on the available data. We would not expect that excess cellulosic RIN generation would impact the price of other RIN types, however excess cellulosic RIN generation would be expected to negatively impact the price of cellulosic RINs, which would result in lower incentives for the production and use of cellulosic biofuels. We do not anticipate that we will need to use the cellulosic waiver authority to reduce the cellulosic biofuel volumes we are establishing in this rule. We therefore do not expect that cellulosic waiver credits will be available to obligated parties, however we noted that we do retain the authority to reduce the required cellulosic biofuel volumes if the statutory criteria for waiving the volumes are met. If we were to reduce the cellulosic biofuel volumes we are establishing in this final rule using our cellulosic waiver authority we would make cellulosic waiver credits available to obligated parties, consistent with the statutory provisions for this waiver authority.

Comment:

A commenter stated that EPA's requirements for demonstrating cellulosic biofuel production for different types of cellulosic biofuel were inappropriately inconsistent. Specifically, the commenter stated that digesters and cellulosic ethanol production from corn kernel fiber are held to different standards. The party claimed that the production of cellulosic ethanol from corn kernel fiber should be allowed to use the same conservative assumption approach to calculate cellulosic biofuel production that EPA proposed for waste digesters.

Response:

To qualify as cellulosic biofuel under the RFS program the statute requires that a fuel must be derived from cellulose, hemicellulose, or lignin that is derived from renewable biomass and that the fuel must have lifecycle greenhouse gas emissions that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions. As explained in Preamble Section X.C to this final rule, EPA has determined that the differences in the nature of the feedstocks (e.g., digester feedstocks are generated as physically separate streams such that the mass, moisture content, and methane production potential of each feedstock can be independently determined before mixing) and the fuel conversion technologies between mixed waste digesters and the conversion of corn kernel fiber to ethanol merit different requirements for demonstrating the conversion of cellulose, hemicellulose, or lignin to transportation fuel. While some of the existing requirements for measuring cellulosic conversion and apportioning RINs for co-processed cellulosic and non-cellulosic feedstocks are unnecessary or inappropriate for mixed feedstocks in an anaerobic digester, this is not the case for the conversion of CKF to ethanol. Under the recently released guidance on qualifying an analytical method for determining the cellulosic converted fraction of CKF co-processed with starch, EPA laid out several methods parties can use to calculate cellulosic biofuel production under the existing regulatory requirements at 40 CFR 80.1450(b)(3)(xiii)(B). Additionally, even if we were to allow that the renewable fuel producers processing corn kernel fiber simultaneously assume any ethanol produced above the theoretical maximum production from starch could be eligible to generate cellulosic RINs, we do not expect that they would be able to generate any cellulosic RINs. Finally, we note that we are not reopening the regulatory requirements or guidance for producers of ethanol from CKF in this rule.

Comment:

A commenter stated that the cellulosic biofuel volumes are too high, noting that there is a lack of cellulosic ethanol production capacity.

Response:

The required cellulosic biofuel volumes in this final rule are based on our review of the statutory factors. The cellulosic biofuel volume requirements we are finalizing are achievable and reflect the projected growth in cellulosic biofuel production from 2023–2025 in light of the incentives available to cellulosic biofuel producers from the RFS program and other state and federal programs based on the available data. These volumes do significantly exceed the production capacity for cellulosic ethanol in the U.S. However, the volumes are based on a consideration of all types of cellulosic biofuel projected to be produced or imported in 2023–2025, not just cellulosic ethanol. Based on these projections, the cellulosic biofuels volumes are reasonable and consistent with our consideration of the statutory factors.

Comment:

A commenter stated that cellulosic waiver credits should be available to obligated parties each year from 2023–2025.

Response:

The statute directs EPA to offer cellulosic waiver credits to obligated parties when EPA reduces the required volume of cellulosic biofuel using our cellulosic waiver authority. CAA section 211(o)(7)(D)(ii). We are not exercising our cellulosic waiver authority in this rule, and are therefore not making cellulosic waiver credits available to obligated parties at this time.

Comment:

A commenter stated that EPA's process for reducing the cellulosic biofuel volumes using the cellulosic waiver authority is too slow. This commenter stated that EPA should establish criteria that automatically triggers waivers under certain circumstances.

Another commenter stated that EPA should investigate whether they have authority under the Clean Air Act to adopt a mechanism to stabilize RIN prices.

Response:

In order to exercise the cellulosic waiver authority, the statute requires that the Administrator determine that the projected cellulosic biofuel production is less than the minimum applicable volume.[9] As we have just established the cellulosic biofuel standard in this action at the level we believe can be achieved, we do not believe a mechanism that would automatically adjust the

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

required volume of cellulosic biofuel is merited. See RTC Section 2.3.2 and Preamble Section VI.A for a further discussion of our response to comments related to a mechanism that would automatically adjust the required volume of cellulosic biofuel.

3.2 Methodology for Projecting Volumes

Comment:

EPA should project cellulosic biofuel volumes based on historical annual increases.

Response:

In projecting cellulosic biofuel production and imports in 2023–2025 we have considered all available data, including the historic annual increases in cellulosic biofuel production, as suggested by the commenter. Our projections of cellulosic biofuel production and imports are discussed in RIA Chapter 6.1. While historical annual increases can help inform future production of cellulosic biofuel it is important to also consider other factors, such as investment in cellulosic biofuel production, consideration of newly approved cellulosic biofuel pathways and facilities expected to register as cellulosic biofuel producers, any potential limitations on feedstocks or the use of cellulosic biofuel as transportation fuel, and the ability for the RFS program to incentivize future volumes.

Comment:

EPA should proceed cautiously when projecting eRIN volumes, as growth in eRIN production is uncertain. The commenter recommends using a 13% growth rate to project cellulosic biofuel production in future years, and that EPA should not project eRIN volumes beyond this 13% growth rate.

Response:

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking. We therefore have not included eRINs in our projections of cellulosic biofuel production. We address comments related to the proposed 13% growth rate for RNG use as CNG/LNG in RTC Section 3.2.2.

3.2.1 Methodology for Projecting Liquid Cellulosic Biogas Volumes Including Corn Kernel Fiber

Comment:

Multiple commenters stated that EPA should include ethanol produced from corn kernel fiber (CKF) in our projections of cellulosic biofuel production. Multiple commenters stated that the liquid cellulosic biofuel volumes should be increased by up to 250 million gallons per year to account for CKF production. Other commenters similarly noted that significant volumes of ethanol produced from CKF were credited under the LCFS program in the last 12 months (numbers cited ranged from 120 million gallons to 168 million gallons). One commenter projected the production of ethanol from CKF at 375 million gallons using what they characterized as a conservative converted fraction number or the methodology approved under California's LCFS program. One commenter stated that EPA should account for ethanol produced from CKF in 2024 and 2025 to reflect production from facilities that register according to the updated guidance document published by EPA. One commenter stated that they expected EPA to be receiving registration requests for facilities to produce ethanol from CKF in the near term, and that EPA should approve these requests and include the projected production from these facilities in our liquid cellulosic biofuel projections.

Response:

The cellulosic biofuel volumes in this final rule are based on the projected production and imports of cellulosic biofuel in 2023–2025, which includes the expected production of ethanol from CKF. While at proposal it was unclear whether any additional facilities would be able to register to produce ethanol from CKF during 2023–2025, based on updated information available for the final rule, we now anticipate approving registration requests for facilities during this time frame.

The methodology used to project the production of cellulosic ethanol from CKF in these years considers the number of facilities we expect to be able to register each year using quantification methodologies that are consistent with the current guidance issued by EPA and the proportion of total ethanol production from these facilities we project will be produced from CKF (rather than corn starch). Our projections are described in RIA Chapter 6.1.2. The volumes of ethanol we project will be produced from CKF are lower than the projections from these commenters, which appear to assume that all or nearly all corn ethanol producers register as cellulosic biofuel producers and/or convert a greater fraction of the grain into cellulosic ethanol. The relatively high volumes of ethanol from CKF reported in California's LCFS program that were highlighted in the comment are likely due to the fact that unlike the RFS program California's LCFS program does not require that producers of ethanol from CKF demonstrate that the fuel is produced from cellulose, hemicellulose, or lignin. Because of this requirement of the RFS, our projections are lower than those of the commenters', which do not account for the required demonstration. As discussed further in RIA Chapter 6.1.2, the proportion of total ethanol production from these facilities from CKF used in our projection of cellulosic biofuel production is based on conversations with companies working to quantify the production of ethanol from cellulosic feedstocks at corn ethanol facilities. Any comments related to actions on specific facility registration requests are beyond the scope of this rule.

Comment:

A commenter stated that EPA's projection of liquid cellulosic biofuel production should be higher. The commenter specifically mentioned that the projected volumes should include production from Fulcrum, American GreenFuels Rockwood, and cellulosic SAF production.

Similarly, another commenter stated that EPA's projections of liquid cellulosic biofuel production ignored several SAF producers that will produce millions of gallons of SAF each year from cellulosic feedstocks. The commenter stated that the projected cellulosic volumes must be increased to meet the Administration's SAF production goals.

Response:

EPA considered cellulosic biofuel production from all potential producers of liquid cellulosic biofuel in this final rule. With respect to the facilities mentioned by the commenter we note that despite publicly stating that they had begun producing biocrude at their Nevada facility, Fulcrum has not registered as a cellulosic biofuel producer, nor has any facility registered to produce cellulosic biofuel using biocrude produced by Fulcrum. EPA was unable to find any public information (including in the public comments) that would suggest American GreenFuels Rockwood would produce commercial scale quantities of cellulosic biofuel by 2025. Similarly, we were unable to find any information that would suggest any facilities would produce commercial scale quantities of SAF from cellulosic feedstocks by 2025. Even if a small number of facilities such as those listed by the commenter or others not considered by EPA are able to produce cellulosic biofuel by 2025 the total production of cellulosic biofuel from these facilities is highly unlikely to significantly impact our overall projection of cellulosic biofuel production for 2023–2025.

As far as increasing cellulosic volumes for the purpose of furthering the Administration's SAF production goals, we are not aware of any facilities that intend to produce SAF from cellulosic feedstocks by 2025. It would therefore not be appropriate or effective to attempt to support SAF production by increasing the cellulosic biofuel volume requirements for 2023–2025 in the RFS program.

Comment:

A commenter stated that EPA should project greater volumes of co-processed cellulosic biofuels.

Response:

At this time, we are not aware of any facilities that intend to co-process cellulosic feedstocks with non-cellulosic feedstocks to produce qualifying cellulosic biofuel. The commenter did not provide any information on facilities intending to produce cellulosic biofuel in this manner. We therefore have not included any co-processed cellulosic biofuel in our projections of liquid cellulosic biofuel production.

Comment:

A commenter stated that the percentile values EPA used to project liquid biofuel production within the projected ranges are too low and are punitive to future cellulosic biofuel producers. The commenter stated that in calculating the percentile values EPA should not consider data from 2020 due to the impacts of the COVID pandemic.

Response:

In this final rule we have not used percentile values to project liquid cellulosic biofuel production. The percentile values used in the proposed rule and in previous RFS rules were generally based on actual vs. projected production from stand-alone first-of-a-kind facilities.[10] In this final rule the only liquid cellulosic biofuel production we are projecting is ethanol produced from CKF at existing corn ethanol production facilities. Because these facilities have an established history of ethanol production, we do not believe the percentile values used in the proposed rule or previous RFS rules accurately reflect likely future production of ethanol from CKF from these facilities. For more information on our projection of ethanol from CKF, see RIA Chapter 6.1.2.

Comment:

A commenter supported EPA's projections of the production of liquid cellulosic biofuel. The commenter stated that no facilities have been registered to produce ethanol from CKF, and that because of this EPA should not include volumes of this fuel in our projections.

Response:

Our projections of liquid cellulosic biofuel production other than ethanol from CKF in this final rule are similar to, but slightly lower than, our projections in the proposed rule (no production in the final rule vs. 0–5 million ethanol-equivalent gallons per year in the proposed rule). As discussed in RIA Chapter 6.1.2, we are including projected volumes of ethanol produced from CKF in our projections of cellulosic biofuel production and imports for this final rule based on conversations with a number of corn ethanol production facilities who intend to register as cellulosic biofuel producers using methodologies to quantify cellulosic biofuel production that are consistent with our current guidance.

[10] In some years we did consider historical production vs. projected production from producers of ethanol from CKF when developing the percentile values to project liquid cellulosic biofuel production. The projected contribution from these facilities was small relative to the total projected liquid cellulosic biofuel production, and in some of these cases the technology used by producers involved a second production train to convert cellulosic feedstocks (rather than co-fermenting starch and cellulosic feedstocks using existing equipment and processes) and was much more similar to other potential cellulosic biofuel producers using first-of-a-kind technologies.

3.2.2 Methodology for Projecting Cellulosic Biogas Volumes

Comment:

EPA received many comments on the rate of growth that should be used to project the production of RNG used as CNG/LNG in 2023–2025. One commenter supported EPA's proposed methodology of projecting future growth in RNG used as CNG/LNG using data from the past two years. Many of these commenters stated that EPA should not use a growth rate based on the past two years of data. Commenters often claimed that the proposed rate of growth and resulting volumes for RNG used as CNG/LNG did not reflect the industry's existing investments in RNG production or the potential for investment that could result from the incentives provided in the Inflation Reduction Act. Some commenters cited the impacts of the COIVD pandemic as justification for not just relying on data from the past two years, while others noted the general uncertainty surrounding the RFS program and low cellulosic RIN prices during this time.

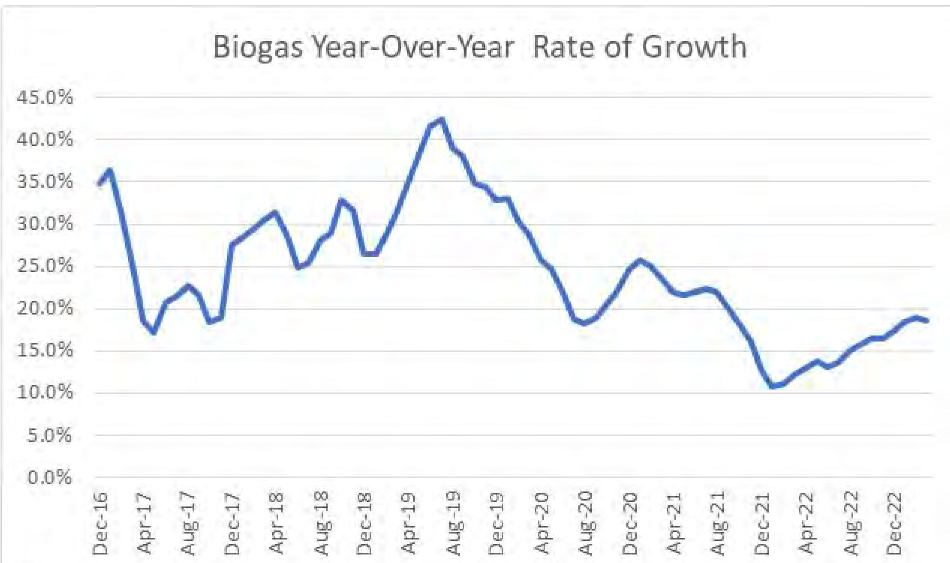
Multiple commenters recommended using a 20% year-over-year growth rate (one commenter stated that using a 20% growth rate would result in volumes of 756, 907, and 1089 million RINs in 2023–2025 respectively). Other commenters suggested that EPA should use a 30% growth rate (which reflects the average rate of growth from 2015–2019), with some of these commenters characterizing this growth rate as conservative and/or the minimum growth rate that EPA should consider. Many commenters stated that data from Argonne National Lab and/or the Coalition for Renewable Natural Gas supported a 30% growth rate based on RNG facilities that are currently producing, newly built, under construction, and in development. Other commenters suggested the rate of growth for CNG/LNG of 50%, with one commenter suggesting a 65% rate of growth.

Response:

In this final rule we have projected the production of RNG used as CNG/LNG in 2023–2025 using a projected growth rate of 25%. This growth rate is significantly higher than the proposed growth rate of 13%. It is higher than the growth rate requested by many commenters but lower than that requested by many other commenters. This growth rate was calculated from historical data from 2015–2022 instead of just the most recent 24 months, and as discussed below, we believe the longer historical period provides a better basis for projecting production in 2023-25. As stated in RIA Chapter 6.1.3, we believe the incentives provided by the RFS program, existing and potentially newly adopted state programs, and the extension of the investment tax credit to qualified biogas facilities in the IRA are sufficient to support growth in the production and use of RNG used as CNG/LNG as the rates observed in previous years.

The observed growth rates in the recent months since the proposed rule provide support for using a growth rate calculated using data from 2015–2022 to project future growth in RNG used as CNG/LNG. The observed year over year growth rate for RNG used as CNG/LNG reached a low of just approximately 11% in January 2022. Notably, this is approximately 2 years after the beginning of the COVID pandemic. The pandemic may not have significantly impacted the production of RNG used as CNG/LNG or the use of CNG/LNG as transportation fuel, but it likely did impact the development of new facilities capable of producing RNG that could be used as CNG/LNG in the transportation sector. In discussions with EPA, project developers have indicated that it takes approximately two years to develop a new RNG project. Taken together, this data would strongly suggest that the COVID pandemic was one, if not the key factor in the decreasing observed growth rates for RNG used as CNG/LNG through January 2022.

Since January 2022 the observed year over year growth rate for CNG/LNG has steadily increased, reaching 18.6% in March 2023. Were the observed increases in the rate of growth from January 2022 to March 2023 to continue, the observed rate of growth is projected to reach approximately 25% by December 2023. These data provide further support for using the 25% growth rate calculated from observed data from 2015–2022 to project CNG/LNG production in 2023–2025.



We acknowledge that using a growth rate based on data from 2015–2022, rather than a growth rate based on data from the most recent 24 months, is a change from the methodology used in previous RFS rules. In the 2020–2022 rule we stated that using an average growth rate from 2015-2020 or 2015-2021 to project the production of RNG used as CNG/LNG would not be appropriate when more recent data suggests a lower growth rate in more recent years, and that this was especially true when there is reason to expect that the annual growth rate for RNG used as CNG/LNG will decrease over time. We also cited fairly consistent EIA estimates of the quantity of CNG/LNG used as transportation fuel from 2019–2021 and concluded that the use of this fuel did not appear to be significantly impacted by the COVID pandemic.

Since finalizing the 2020–2022 rule we have additional data that supports the projection methodology we are using to project the production of RNG used as CNG/LNG in 2023–2025. As discussed above, while the observed year over year growth rate in March 2023 is still lower than the growth rate calculated using data from 2015–2022 this growth rate has been increasing steadily over the past year, and if the current trajectory continues the growth rate is projected to reach 25% by December 2023. Further, while the COVID pandemic does not appear to have had a significant impact on the use of CNG/LNG as transportation fuel, it does appear that it significantly impacted the development of RNG projects, which impacted the growth of the production and use of RNG used as CNG/LNG through 2022. Finally, we note that in this final rule we are prospectively projecting volumes for 3 years, rather than just a single year in the 2020–2022 RFS rule. In this context we believe it is more appropriate to consider a growth rate based on a longer data set, as we are using this growth rate to project CNG/LNG volumes farther into the future. We will continue to monitor the market for RNG used as CNG/LNG, and anticipate adjusting our projection methodology based on the observed data in subsequent RFS rules.

Comment:

Multiple commenters stated that EPA should recognize post-pandemic growth in RNG production when projecting volumes for 2023–2025.

Response:

As discussed in the previous response, the growth rate used to project the production of RNG used as CNG/LNG in 2023–2025 takes into consideration the growth in RNG production in recent years.

Comment:

A commenter supported EPA's projected growth rate of 13%, but stated that EPA should only apply this growth rate to project volumes of RNG used as CNG/LNG for 2025 because EPA has missed the statutory deadline for establishing RFS volumes for 2023 and 2024.

Response:

We acknowledge that we have not met the statutory deadlines for establishing RFS volumes for 2023 and 2024. Nevertheless, as discussed in Preamble Section II.E we retain the authority to promulgate volumes and annual standards beyond the statutory deadlines so long as we exercise this authority reasonably, as we have done in this final rule. See the first response in this subsection for a discussion of the rate of growth used to project the CNG/LNG volumes for 2023–2025.

Comment:

A commenter stated that EPA must use more recent data when updating the projection methodology and rate of growth for the final rule.

Response:

We have used data from 2015–2025 to calculate the growth rate used to project the production of CNG/LNG derived from biogas from 2023–2025. We also considered additional data through March 2023, the most current data available at the time the analyses for this final rule were completed, when considering the appropriate growth rate to use when projecting future production of CNG/LNG derived from biogas.

Comment:

A commenter stated that there was more biogas produced in 2022 than was indicated by RIN generation due to a lack of certainty regarding the RFS program and low RIN prices.

Response:

We recognize that it is possible that some volumes of biogas that could be used as CNG/LNG in the transportation sector can be used in other markets when given sufficient economic incentives and/or mandates to do so. The commenter did not provide an estimate for the quantity of biogas used in other markets in 2022. We expect, however, that the volume of this fuel used in other markets was relatively small. D3 RIN prices averaged approximately $3 per RIN in 2022 or almost $40 per MMBTU of CNG/LNG. This incentive was far higher than the value of the biogas itself, as the Henry Hub spot prices for natural gas ranged between $4 and $9 per MMBTU in 2022. Thus, the RFS program provided a very strong incentive for the use of qualifying CNG/LNG as transportation fuel in 2022 despite the RIN prices and whatever uncertainty there may have been with the RFS program. It is therefore unclear whether and to what extent any biogas that may have been used in non-transportation markets in 2022 would be available as transportation fuel in 2023–2025.

Comment:

Multiple commenters stated that the projected volumes for 2023 are less than the current production capacity for RNG.

Response:

We recognize that commenters identified production capacity for RNG that exceeds the proposed volumes for RNG used as CNG/LNG in 2023. This information alone, however, is not a sufficient basis for projecting the production of RNG used as CNG/LNG in future years. First, RNG facilities, like all biofuel production facilities, often operate at levels lower than their production capacity given real world limitations. Second, not all RNG qualifies as cellulosic biofuel in the RFS program. RNG must be produced from qualifying feedstocks and used as transportation fuel to be eligible to generate RINs in the RFS program. Finally, we note that EPA previously attempted to project the production of CNG/LNG based on the facility capacities and facilities under construction (we last used this projection methodology for RNG used as CNG/LNG in the 2017 RFS annual rule). This projection resulted in over-projections of RNG used as CNG/LNG. As noted in Preamble Section III.B.1, we have successfully used an industry-wide projection methodology in previous years and continue to believe it better reflects the projected growth of the industry based on the available data in light of potential limiting factors (which are more likely to be market based than technology based) than a projection based on an assessment of each potential RNG producer.

Comment:

A commenter stated that EPA should not use the same growth rate to project the volume of CNG/LNG in all three years. Multiple commenters stated that historic growth rates are not indicative of future growth rates, and that the volumes EPA projected using the rate of growth methodology do not reflect the volumes of RNG used as CNG/LNG that are achievable.

Response:

. While we recognize that historic growth rates are not always indicative of future growth, we have successfully used an industry-wide projection methodology in previous years and have found it to be a reliable predictor of future performance for this sector as discussed above in the first response in this subsection. We note that growth rates significantly higher than those we are using to project the production of RNG used as CNG/LNG in this rule would result in projections that exceed the volume of this fuel projected to be used as transportation fuel. Thus, even if significantly greater quantities of RNG could be produced, there are limits to the quantity of this fuel that can be used as transportation fuel, which is a requirement to generate RINs in the RFS program.

Comment:

Multiple commenters presented a correlation of RIN prices (with an 18 month offset) and the growth rate for RNG used as CNG/LNG. These commenters claimed that the high RIN prices observed in 2021 and 2022 supported a 30% rate of growth for RNG used as CNG/LNG.

Response:

EPA considered the correlation between RIN prices (with the 18 month offset suggested by the commenters) and the generation of D3 RINs for RNG used as CNG/LNG. While there does appear to be a general correlation between RIN prices and RIN generation, we note that the correlation is weaker when RIN prices are greater than $1.50, as they have been since 2021. Further, an observed correlation between the cellulosic RIN price and rate of growth in cellulosic biofuel does not necessarily demonstrate that the higher RIN prices are causing the higher growth rate. We note that in the 2020–2022 RFS rule, commenters suggested that a 24 month offset between RIN prices and cellulosic RIN generation was appropriate. The fact that commenters now suggest a different offset (or time lag) is appropriate in this rule suggests that any observed relationship between RIN prices and production 18 months later may not reflect causation. We therefore do not necessarily believe this correlation is a reliable predictor of future production of RNG used as CNG/LNG. Even if we were to accept that this correlation provides a reliable methodology to project future generation of RNG used as CNG/LNG it would be of limited value in this rule, as we are establishing cellulosic biofuel volumes through 2025 and we are unable to project cellulosic RIN prices with any degree of confidence for future years.

Comment:

A commenter stated that EPA projected cellulosic RIN prices of $3.06 per RIN, and that EPA must establish higher cellulosic biofuel volumes for 2023–2025 to achieve this RIN price.

Response:

EPA did not project cellulosic RIN prices at $3.06 for future years. In the context of projecting the fuel price impacts we assumed that the RIN prices in future years would be equal to the average RIN prices observed over the most recent 12 months. Our cellulosic biofuel volumes are not designed to achieve a particular RIN price nor is attempting to achieve a specific RIN price one of the factors that EPA considers when setting volumes for 2023 and beyond.

Comment:

A commenter claimed that EPA incorrectly stated that access to a pipeline interconnect could limit RNG production, and that this was not true based on the commenter's experience.

Response:

It is unlikely that access to a pipeline interconnect would technically limit a potential source of RNG from access to the pipeline distribution network and ultimate use as as CNG/LNG. However, depending on the location of the potential RNG source and the quantity of RNG that could be produced, adding a pipeline interconnect can add significant cost to an RNG project. These costs may cause potential investors to consider alternative uses for the biogas or investments in other projects altogether.

Comment:

Multiple commenters stated that EPA should project the production of RNG used as CNG/LNG based on expectations of demand from vehicles and fleets expected to use CNG/LNG or long-term growth rates for demand from CNG/LNG vehicles.

A commenter stated that data from EIA shows that the use of CNG/LNG as transportation fuel will not limit the generation of RINs for RNG used as CNG/LNG. Another commenter similarly stated the use of CNG/LNG as transportation fuel would not limit RIN generation, and that the incentives provided by the RFS program could result in the greater adoption of CNG/LNG vehicles, increasing the use of CNG/LNG as transportation fuel

One commenter stated that dispensing infrastructure and the quantity of CNG/LNG used as transportation fuel would not limit the number of RINs that could be generated for RNG used as CNG/LNG.

Response:

While the use of CNG/LNG in the transportation sector is one potential constraint for the use of these fuels in the RFS program, it's not the only constraint. As discussed in RIA Chapter 6.1 and in the comment responses in this section we think the primary constraint in 2023–2025 on the production of qualifying CNG/LNG derived from biogas and its use as transportation fuel are related to the production, capture, and pipeline injection of qualifying biogas. Nevertheless, we have assessed the use of CNG/LNG as transportation fuel in 2023–2025 since this could also potentially limit the generation of cellulosic RINs for this fuel.

Our projections of the quantity of RNG used as CNG/LNG used as transportation fuel are presented in RIA Chapter 6.1.3. The various projections of CNG/LNG used as transportation fuel range presented in the RIA are about 1.4 billion RINs in 2022 (EPA methodology), 1.5–1.6 billion RINs in 2023–2025 (Bates White methodology), and 1.6–1.75 billion RINs in 2023–2025 (EIA AEO). These latter numbers are likely to be an over-estimate of the quantity of CNG/LNG used in domestic transportation fuel, as a significant portion of the fuel is projected to be used in international shipping.[11] The quantity of RNG used as CNG/LNG that EPA projects will be used in 2025 (1.3 billion RINs) appears to be approaching the total quantity of this fuel used as transportation fuel in 2025. An estimate of the use of CNG/LNG in the transportation sector provided in comments by NGVAmerica (approximately 900 million ethanol equivalent gallons based on their statement that 64% of all natural gas used in on-road transportation was renewable in 2021)[12] is even lower than those provided in the RIA. While it is possible that the total quantity of CNG/LNG used as transportation fuel will increase through 2025, neither Bates White or EIA project significant increases in 2023–2025. Further, it is unlikely that parties will be able to generate RINs for every ethanol-equivalent gallon of CNG/LNG used as transportation fuel, and therefore the practical limit of the number of RINs that can be generated for this fuel is likely somewhat less than the total quantity used as transportation fuel.

We do not expect that the use of CNG/LNG as transportation fuel will limit RIN generation for RNG used as CNG/LNG through 2025 based on our projections in this rule. However, were we to project volumes using a significantly higher rate of growth the RIN generating volumes of RNG used as CNG/LNG would be expected to be limited by the quantity of this fuel used as transportation fuel. We do not expect that dispensing infrastructure will present a practical limit on the number of RINs that can be generated for CNG/LNG used as transportation fuel, but it is possible that the size of CNG/LNG fleet may limit RIN generation in future years beyond 2025.

Comment:

Multiple commenters stated their concern that EPA may be double-counting RNG in our estimates of RIN generation for RNG used as CNG/LNG and eRINs. One commenter stated that if EPA project increasing volumes of RNG to eRINs in our final rule we must project lower volumes of RNG to CNG/LNG.

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[11] See EIA 2022 AEO Table 36. Transportation Sector Energy Use by Fuel Type Within a Mode.
[12] See EPA-HQ-OAR-2021-0427-0693.

Response:

We are not taking a final action on the proposed eRIN provisions in this rule.

Comment:

A commenter stated that the EIA data used by EPA to calculate the rate of growth is already out of date, and is inconsistent with the data from EPA's EMTS.

Response:

EPA did not rely on data from EIA to calculate the growth rate for RNG used as CNG/LNG used to project the future volumes in this rule.

Comment:

A commenter claimed that current levels of production of RNG used as CNG/LNG are equal to or greater than e the projected volumes of CNG/LNG derived from biogas for 2023 in the proposed rule. These commenters generally requested that EPA increase our projection of the production of CNG/LNG derived from biogas in the final rule.

Response:

We have revised our projection of the production of RNG used as CNG/LNG in this rule. The current projection of RNG used as CNG/LNG for 2023, reflects a 25% rate of growth over the quantity of RNG used as CNG/LNG supplied in 2022, Our current projection for the production of this fuel is also higher than the annualized number of RINs reported for all months[13] through March 2023.

Comment:

A commenter claims that there is already a 6% oversupply of cellulosic RINs.

Response:

The commenter does not provide a basis for their estimate of the current oversupply of cellulosic RINs. As such, the commenter did not raise the issue with reasonable specificity. In EPA's own review of the updated data, EPA found that the generation of RINs for CNG/LNG in 2022 (666 million) is greater the projected number of RINs generated for this fuel in the 2020–2022 rule (632 million). At this time, we do not have sufficient data to determine the number of cellulosic carryover RINs (RIN surplus) that will be available in 2023. As discussed in RIA Chapter 1.11, we currently project very few, if any, cellulosic carryover RINs will be available in 2022. While cellulosic RIN generation in 2022 exceeded the volume that served as the basis for the cellulosic biofuel percentage standard for 2022, we will not know the actual cellulosic RIN obligation for

[13] With the exception of RIN generation in December the past several years, which generally represents two months' worth of RIN generation for RNG used as CNG/LNG.

2022 until obligated parties submit their compliance reports for that year (December 1, 2023). In both 2020 and 2021 the actual RIN obligations reported by obligated parties exceeded the intended volume requirements, significantly drawing down the cellulosic biofuel carryover RIN balance, and it is possible that this will again be the case in 2022. Finally, and perhaps most importantly, even if there were a 6% RIN surplus as claimed by the commenter the commenter does not provide support for their claims that this level of surplus is detrimental to the market for cellulosic biofuel or RINs. As discussed in greater detail in RTC Section 2.6.2 of the RTC for the 2020–2022 RFS rule, the number of available carryover RINs exceeded 6% in 2015–2017 and 2019, with no discernable negative impact on the cellulosic market. In fact, some of the highest observed growth rates occurred in 2016 and 2019.

4. Biodiesel and Renewable Diesel

4.1 Biodiesel and Renewable Diesel Production Capacity

Comment:

Multiple commenters stated that the proposed advanced biofuel and BBD volumes were well below the domestic production capacity for biodiesel and renewable diesel. Other commenters similarly stated that the proposed volumes for these categories did not reflect the investments made to increase production capacity in recent years. Several of these commenters cited to estimates of biodiesel production capacity from the proposed rule, more recent EIA estimates, or other sources.

Similarly, commenters stated that EPA seemed to ignore increasing production capacity when determining the BBD and advanced biofuel volumes in the proposed rule. Another commenter similarly stated that EPA did not properly consider available production capacity when determining the proposed volumes.

Estimates of production capacity varied. Some commenters stated that biodiesel and renewable diesel production capacity was currently at 4 billion gallons and could reach 7–7.3 billion gallons (12 billion RINs) by the end of 2025. Other commenters focused primarily on renewable diesel, with estimates of production capacity in 2025 ranging from 4.6–5.9 billion gallons.

Response:

Our assessment of the domestic production capacity of biodiesel and renewable diesel is presented in RIA Chapter 6.2.2. As discussed in Preamble Sections III.B.2 and VI.B and RIA Chapter 6.2, we do not expect that the production of biodiesel and renewable diesel will be limited by the production capacity for these fuels. Historically the production capacity of biodiesel and renewable diesel has exceeded domestic production, in some years by a significant margin. Thus, while we have updated our projections of biodiesel and renewable diesel production capacity in this final rule, these updates did not have a direct impact on the volume of these fuels we project will be produced in the U.S. in 2023–2025.

Comment:

A commenter stated that the announced increase in renewable diesel production from one company alone (Chevron) was sufficient to meet the entire increase in biomass-based diesel and advanced biofuel volumes through 2025.

Response:

We recognize that the domestic renewable diesel production capacity is projected to increase rapidly in 2023–2025, however this increase in production capacity is not expected to result in a direct increase in renewable diesel production due to other limitations, the most significant of which is the limited availability of qualifying feedstocks (see RTC Section 4.2 and RIA Chapter

6.2). Further, as discussed in Preamble Section III.C, we project that significant volumes of biodiesel and renewable diesel will be used beyond the volumes necessary to meet the advanced biofuel and biomass-based diesel volume requirements. We expect that the volumes we are finalizing in this rule will result in an increase in the supply of advanced biodiesel and renewable diesel of approximately 2 billion RINs from 2022–2025 (See RIA Table 3.3-1).

Comment:

A commenter stated that EPA's estimates of grandfathered biodiesel and renewable diesel production capacity (3.6 billion gallons) are inconsistent and must be incorrect.

Response:

EPA has updated our estimates of the grandfathered biodiesel and renewable diesel production capacity in this rule. Our revised estimate, presented in RIA Chapter 6.7, is lower than the estimate in the proposed rule.

Comment:

A commenter stated that EPA should update our projections of biodiesel and renewable diesel production in the final rule to better reflect the expected increases in production capacity for these fuels. Another commenter noted that EIA projects that the production of biodiesel and renewable diesel will follow the increases in production capacity.

Another commenter stated that the production capacity numbers in the proposed rule were outdated and needed to be updated for the final rule.

Response:

We have updated our projections of biodiesel and renewable diesel production capacity for 2023–2025 based on updated projections from EIA, data from EMTS, and other publicly available information. Our updated projections are presented in RIA Chapter 6.2.2.

Comment:

Multiple commenters stated that EPA should include announced investments in SAF production capacity in our estimates of biodiesel and renewable diesel production capacity.

Response:

As discussed in Preamble Section III.B.2, through 2025 we project that SAF will be produced using the same feedstocks and technologies, and at largely the same facilities, as renewable diesel. We recognize that production of SAF may be greater than we project in this rule, however we expect that because SAF is produced from the same feedstocks and often at the same facilities as renewable diesel any increase in SAF production relative to our projections would result in a corresponding decrease in renewable diesel production, with little or no net change in the total production of biomass-based diesel (which includes SAF).

4.2 Availability of Biodiesel and Renewable Diesel Feedstocks

Many commenters that discussed the availability of biodiesel and renewable diesel feedstocks also discussed the impact of the proposed volumes on vegetable oil and food prices. Responses to these comments can be found in RTC Section 9.1.5.

Comment:

Multiple commenters stated that EPA should reconsider our projections of vegetable oil and oilseed production through 2025.

Multiple commenters stated that the proposed BBD and advanced biofuel volumes are not in alignment with the investments currently being made to increase the production of feedstocks for these fuels. Other commenters similarly stated that EPA failed to consider how investment in feedstock production would impact the availability of feedstocks that could be used to produce biodiesel and renewable diesel, and that the impact of these investments should be incorporated into EPA's estimates.

Response:

We have updated our projections of the availability of feedstocks to produce biodiesel and renewable diesel, including projections of vegetable oil and oilseed production, in this final rule. Our updated assessment of available feedstocks can be found in RIA Chapter 6.2.3, and an assessment of the projected supply of biodiesel and renewable diesel based on this updated feedstock assessment can be found in RIA Chapter 6.2.6. In this final rule we project, based on our updated projections of available biodiesel and renewable diesel feedstocks, that the production and import of biodiesel and renewable diesel will increase by over 1.1 billion gallons (approximately 2 billion RINs) from 2022 to 2025 (See RIA Table 3.3-1 and 3.3-2).

Comment:

Multiple commenters stated that the USDA projections EPA used as the basis for expected growth in domestic vegetable oil production were not an appropriate source for these projections. These commenters generally stated that the USDA Agricultural Projections to 2031 used by EPA in the proposed rule assumed no increases in the RFS volume requirements, and therefore did not properly reflect the potential growth in domestic vegetable oil production through 2025.

Response:

EPA confirmed with USDA that the projections in the USDA Agricultural Projections to 2031 did not consider potential increases in demand for vegetable oil for biofuel production from higher RFS standards in 2023–2025 (relative to the required volumes for 2022), nor did they include a consideration of the announced investments in oilseed crushing facilities in the U.S. In this final rule we have therefore not based our projection of domestic vegetable oil production on the USDA Agricultural Projections to 2032. Instead, we have updated our assessments of domestic vegetable oil production through 2025 based on our assessment of information submitted in the public comments and other publicly available data.

Comment:

Multiple commenters stated that EPA has significantly under-projected the growth in domestic soybean crush and soybean oil production through 2025. Some commenters cited to investments that have been announced by specific companies to increase soybean crush capacity, while others noted investments at multiple facilities across the soybean crushing industry.

Some commenters submitted their own projections for increases in soybean crush or soybean oil production, while others cited to estimates from other sources. Estimates of the increase in soybean crush were as high as 650 million bushels, and estimates of additional soybean oil production ranged from 5–5.5 billion pounds. Estimates of the impact of these investments on soybean oil production ranged from increases of 700 million gallons of soybean oil by 2025 (approximately a 30% increase) to an increase of about 1 billion gallons by 2026.

Response:

In this rule we have updated our projections of the increase in soybean crushing capacity based on our assessment of information submitted in the public comments and other publicly available data. Our updated assessment of available feedstocks can be found in RIA Chapter 6.2.3, and an assessment of the projected supply of biodiesel and renewable diesel based on this updated feedstock assessment can be found in RIA Chapter 6.2.6. Our updated projections are generally consistent with the quantities referenced by the commenters. For example, we currently project that soybean crush capacity will increase by slightly more than 500 million bushels from 2022 to 2025. If fully utilized this crush capacity could produce about 5.85 billion pounds of soybean oil, or enough to produce about 770 million gallons of biodiesel or renewable diesel. We note, however that these values are presented only for the sake of comparison. As discussed in RIA Chapters 6.2.3 and 6.2.6, the actual increase in soybean oil production is projected to be less than this amount as not all of the new capacity will operate for all of 2025, and not all the facilities will operate at their full nameplate capacity.

Comment:

A commenter stated that EPA should not assume that all increases in domestic soybean oil production can be used for BBD production.

Response:

In this final rule we have not assumed that all of the increase in domestic soybean oil production will be available to biofuel producers. Instead, we have estimated that 80% of the increase in soybean will be available for biofuel production, with the remaining 20% available to other markets for soybean oil.

Comment:

Multiple commenters stated that EPA should include greater volumes of canola oil in our projections of feedstock availability through 2025, particularly in light if the recently approved pathway for renewable diesel produced using canola oil as the feedstock. One commenter noted that USDA projected greater use of canola oil for biofuel production in their December 2022 Oil Crops Outlook. This commenter also noted that 20% of the announced increase in crush capacity in the U.S. would be capable of crushing soft seeds such as canola. They further stated that canola production in the U.S. was growing, and that the adoption of double cropping with canola could further increase domestic canola production in future years.

Other commenters focused on the potential for increased canola oil imports from Canada. Multiple commenters stated that significant investments had been made to increase the crushing capacity of canola in Canada. Estimates of the impact of new crush capacity in Canada indicated sufficient canola oil to increase biodiesel and renewable diesel production by 500 million gallons by 2025 and 650–660 million gallons per year by 2026. One commenter noted that most of this production (approximately 80%) is expected to come online by 2024.

Response:

In this final rule we have included quantities of canola oil imported from Canada in our projection of feedstocks available to domestic BBD producers. We acknowledge that this is a change from the proposed rule. In this final rule we primarily based our projection of the production and imports of BBD on our projections of the increase in the production of feedstocks, including soybean oil in the U.S. and canola oil in Canada, rather than only considering increases in domestic feedstock production. We made this change in the final rule for several reasons. First, at the time the analyses were conducted for the proposed rule EPA had not yet approved a pathway to produce renewable diesel from canola oil. As the vast majority of the increase in BBD production through 2025 is projected to be renewable diesel (rather than biodiesel) we did not consider canola oil from Canada in the proposed rule. Since that time, however, we have approved a pathway for renewable diesel produced from canola oil. Second, significant investments have been made in increasing canola crush capacity in Canada that are likely to increase canola oil production through 2025. Thus, the increased use of canola oil imported from Canada is expected to come from increased production, rather than a diversion from existing uses, minimizing the potential negative impacts on existing markets. Third, Canada, like the U.S., is covered by an aggregate compliance approach. This means that any canola oil produced in Canada is very likely to meet the definition of renewable biomass, and that any increase in canola production to supply canola oil to U.S. biofuel producers is unlikely to result in a net increase in cropland in Canada. This increases the likelihood that fuel produced form canola oil in Canada will achieve the intended GHG thresholds and will reduce the potential for negative environmental impacts. Finally, unlike vegetable oil produced in other foreign countries, BBD produced form Canadian canola oil is likely to be produced in the U.S. from imported feedstocks, rather than produced in foreign countries and imported as BBD. This means that BBD produced from Canadian canola oil is much more likely to have positive impacts in the U.S. on rural economic development and employment relative to biofuels produced from feedstocks from other foreign countries.

Our projections of the increase in canola oil production are generally consistent with the information provided by commenters. As a point of comparison, we projected that canola oil production in Canada in 2025 will increase by approximately 2 million metric tons over production in 2022, which could be used to produce approximately 560 million gallons of biodiesel or renewable diesel. We recognize that some of the new and expanded crush capacity in the U.S. is also capable of crushing soft seeds like canola, but we did not project any increase in canola oil production from these facilities as we assumed they were likely to use their available capacity to predominantly crush soybeans. Instead, our projections of increased canola oil production are based on our projection of increased canola crushing in Canada.

While there is the potential for increased canola production in the U.S. in future years, including through the adoption of double cropping with canola we do not believe that this will materially increase vegetable oil production in the U.S. through 2025. Since we expect domestic oilseed crushing facilities to operate at or near their total capacity any increase in the domestic production of canola oil would likely be offset by a decrease in the domestic production of soybean oil.

Comment:

A commenter stated that because soybean oil production can be increased through the increased crushing of soybeans the projected increase in soybean oil production would not require increased soybean planting and would not threaten the 2007 aggregate compliance baseline.

Another commenter similarly stated that increasing soybean crush in the U.S. will result in reduced exports of whole soybeans, which could result in land conversion in other countries to meet global demand for soybeans.

Response:

Our projections of increased soybean oil production are based on a projected increase in soybean crushing. The ultimate impact of increasing demand for soybean oil for biofuel production on domestic soybean planting will largely be dependent on how soybean producers respond to the increased demand for soybeans from crushing facilities. One possible source of soybeans for new/expanded crush facilities are soybeans that are currently exported. If the increased demand for soybeans from crushing facilities results in a decrease in soybean exports there may be little or no impact on domestic soybean production. However, this is not the only possibility, as domestic production of soybeans could also increase. For the analyses related to this rule we have projected that half of the increased in soybeans supplied to crushing facilities come from reduced soybean exports, while the other half would come from increased domestic soybean production.

Further, there is significant uncertainty related to the ultimate impacts of decreasing whole soybean exports, if this is in fact how the market responds to increased domestic crushing of soybeans. While increased soybean production in other countries is one possibility alternatives include the increased production of other oilseed crops and/or a reduction in the consumption of vegetable oils in other markets.

Comment:

A commenter stated that EPA did not provide sufficient support for statements related to projected feedstock limitations.

Response:

We have updated our assessment of the available feedstocks in this rule. As discussed in Section VI.B, we have focused our assessment of feedstock availability on North American feedstock growth as we believe that increasing the production of biofuels from these feedstocks is most likely to result in the greatest benefits and fewest negative impacts. See RIA Chapter 6.2.3.

Comment:

Multiple commenters cited to two different studies that estimated the potential availability of biodiesel and renewable diesel feedstocks conducted by LMC on behalf of industry trade associations. One of these studies focused on projected feedstock availability in North America. This study estimated that there would be sufficient feedstock growth from 2021 to 2025 to produce an additional 1.87 billion gallons of biodiesel and renewable diesel. The other study focused on global feedstock availability and projected that sufficient feedstocks would be available to produce 6.4 billion gallons of renewable diesel for U.S. markets by 2025, after accounting for demand in other countries and other sectors.

Response:

EPA considered these two studies by LMC in our assessment of available feedstocks for BBD production in 2023–2025. Our projections of the growth in the production of feedstocks in North America is generally consistent with the LMC assessment. For example, the LMC assessment found that from 2021–2025 U.S. soybean oil production would increase by about 6.1 billion pounds, Canadian canola oil production would increase by about 5.8 billion pounds, and lesser volumes of distillers' corn oil, animal fats, used cooking oil, minor oilseed crops, and soybean oil would be imported from Mexico. Our assessment projected that from 2022–2025 (one less year than covered by the LMC assessment) soybean oil production would increase by about 5.5 billion pounds, Canadian canola oil production would increase by about 4.3 billion pounds, and we would see lesser increases in distillers corn oil, animal fats, and used cooking oil. One area where our assessments of available feedstocks differ than LMC's assessment is that we project that only 80% of the increase in soybean oil production and 50% of the increase in canola oil production will be available to U.S. biofuel producers.

Commenters also provided an LMC assessment of the global lipid supply through 2025. As with the study discussed previously, this study is directionally consistent with our projection of feedstock availability in the U.S. in that it projects large increases in soybean oil production due to increased crushing and yields. While it is not clear from the study submitted, consistent with previous versions of LMC's assessment of the global supply of lipids, this study appears to consider the potentially available "oil in seed" and does not address potential constraints in oilseed crushing capacity. This reduces its utility in projecting available quantities of vegetable oil in the short term. Finally, while we recognize that additional feedstocks beyond those produced in North America may be available to U.S. biofuel producers, as described in Preamble Section VI.B, our assessment of BBD production and import in 2023–2025 is based on our assessment of the increase in feedstock production in North America.

Comment:

A commenter presented modeling conducted by WAEES that found that even with much greater volumes of biodiesel and renewable diesel than proposed by EPA the price of soybean oil was projected to stay below $0.70 per pound and soybean exports were expected to remain high.

Response:

The modeling conducted by WAEES considered a scenario in which the BBD volume requirement was increased by 500 million gallons per year. This scenario resulted in higher volumes of BBD consumption in the U.S. in 2025 (4.8 billion gallons) relative to the volumes we are finalizing in this rule (4.2 billion gallons). Notably these higher BBD volume requirements resulted in projections of significant increases in imported biodiesel and renewable diesel in 2023–2025 relative to the volume of imported fuels in 2022. Further, when considering the feedstocks used to produce BBD in this scenario relative to the feedstocks used to produce BBD in 2020/2021 the WAEES model projected significant increases in the use of FOG (+2.8 billion pounds) and distillers' corn oil (+0.7 billion pounds), in addition to increases in soybean oil (+7.6 billion pounds) and imported canola oil (+1.1 pounds). As domestic production of FOG and distillers corn oil are not projected to increase significantly through 2025 these results appear to be consistent with EPA's projections that the likely source of feedstocks to produce volumes of BBD higher than we project will be used to meet the volume requirements in this rule would likely be imported and/or diverted from other uses. Finally, we note that while the commenter characterized the impacts of soybean oil prices as staying below $0.70 per pound this price is approximately double the soybean oil prices observed in the market from 2014–2021 (see RIA Chapter 6.2.3).

Comment:

A commenter cited to a study by Lipow Oil Associates that found that BBD production could generate 12.6 billion RINs by 2025, and that based on the LMC global lipid supply study the total global supply of qualifying lipids would be 149 million metric tons by 2025.

Response:

The Lipow Oil Associates analysis referenced by the commenter appears only to consider the production capacity of biodiesel and renewable diesel, not any potential constraints related to the availability of qualifying feedstock. As discussed above and in Preamble Section VI.B, we project that the actual production of biodiesel and renewable diesel will not reach the total production capacity and will instead be limited by the availability of qualifying feedstocks. The LMC assessment of the global supply of lipids is discussed in a previous response.

Comment:

A commenter stated that EPA's own analysis indicated that the feedstock supply for biodiesel and renewable diesel production is constrained, and that higher required volumes for these fuels would incentivize increasing palm oil production and imports.

Response:

We have updated our assessment of the increase in the production of feedstocks for BBD production in North America in this final rule. The volumes of biodiesel and renewable diesel we project will be supplied to meet the volumes we are finalizing in this rule take into consideration the current market in 2023 for imports of BBD and BBD feedstocks and can generally be produced from the projected growth in North American feedstocks. While the impact of the projected increase in the supply of biodiesel and renewable diesel to the U.S. on the global vegetable oil market is uncertain, the projected growth in BBD production through 2025 is based on increases in soybean and canola oil production in North America, not imports of palm oil.

Comment:

A commenter presented their own analysis of biodiesel and renewable diesel feedstock availability that suggested there were sufficient feedstocks for only 2.01–2.05 billion gallons of these fuels in 2023–2025.

Response:

This commenter provided insufficient data to enable EPA to evaluate their projection of available feedstocks. However, their description of the analysis suggests that they did not consider the significant investments currently being made in the soybean crushing capacity or the potential for imported feedstocks or biofuels from Canada or any other country. Thus, this estimate appears to significantly under-project the available supply of BBD feedstocks. Notably this estimate is much lower than the total domestic production of BBD in 2022 (approximately 3 billion gallons) and the total supply of BBD to the U.S. in 2022 after accounting for imports and exports of BBD (approximately 3.1 billion gallons).

Comment:

EPA presents no data to show that the diversion of feedstocks is occuring.

Response:

The volumes of BBD we project will be used to meet the RFS volumes we are finalizing in this rule can be met with the increase in vegetable oil production (soybean oil and canola oil) in North America. As such, we do not expect this rule will result in additional diversion of feedstocks from existing uses for biofuel production in the U.S. As discussed in RIA Chapter 6, because the production of domestic feedstocks for BBD production is limited, higher RFS volumes than we are finalizing in this rule would be expected to result in increased imports of feedstocks and/or biofuels or the increased diversion of feedstocks from existing markets.

Comment:

A commenter stated that an increased use of soybean oil to produce biodiesel and renewable diesel may indirectly increase palm oil production if increasing volumes of palm oil are imported to supply markets that previously used soybean oil.

Response:

We recognize that if soybean oil is diverted from existing markets for biofuel production the markets that previously used soybean oil may look to alternative vegetable oils sources, including palm oil. The volume of biodiesel and renewable diesel we project will be supplied to meet the RFS volumes we are finalizing in this rule can be produced from the projected increase in vegetable oil production in North America in 2023–2025. We therefore do not expect that significant quantities of soybean oil will be diverted from existing uses in the U.S. to meet the RFS volume requirements for these years, and therefore we do not project that these volumes will result in a significant indirect increase in the domestic demand for palm oil.

Comment:

Multiple commenters raised concerns that higher volume requirements for BBD and advanced biofuels would increase the demand for vegetable oils and the price of vegetable oils. Higher vegetable oil prices could also impact the prices of other fats and oils. These commenters stated that the demand and price increases, particularly for refined vegetable oils, could negatively impact food producers. Some of these commenters suggested that demand for refined vegetable oils from biodiesel and renewable diesel producers could result in product shortages and rationing among food manufacturers. One commenter cited to USDA's May 2022 WASDE projections that the use of soybean oil in food production would decrease by 1% as evidence that rationing could occur in the future. These commenters generally stated that EPA should not raise the volume requirements for BBD and advanced biofuels at a time when vegetable oil prices are at historic highs.

Multiple commenters raised concerns about the impact of higher BBD and advanced biofuel volume requirements on pet food manufacturers. These commenters claimed that pet food manufacturers have been facing increasing difficulties sourcing animal fats traditionally used in their products due to increasing competition for these feedstocks from biodiesel and renewable diesel producers. Some of these comments claimed that they could not compete with subsidized biodiesel and renewable diesel producers for these feedstocks. Other commenters cited to IEA estimates that demand for vegetable oils and FOG for biofuel production would increase by 56% from 2022–2027 and expressed concerns about the impact of this increased demand on pet food manufacturers.

Response:

In isolation we would expect that an increase in the demand for vegetable oils for biofuel production (or in any other market) would directly increase the price of vegetable oils. However, there are other factors that are expected to result in decreases in vegetable oil prices, such as higher production of soybeans and an increase in the domestic soybean crush capacity. Over the past year the price of soybean oil has fallen from a high of approximately $0.80 per pound in May 2022 to just over $0.50 per pound in May 2023, even as domestic production of BBD has increased. In projecting the production and import of biodiesel and renewable diesel in this final rule we estimated that 20% of the projected increase in the supply of soybean oil would be available to non-biofuel markets. If realized, this increased production should relieve many of the concerns over the lack of supply of available vegetable oils noted by these commenters. Finally, we note that in the most recent WASDE projection the total quantity of soybean oil projected to be used in the Food, Feed, and Other Industrial markets in 2022/23 and 2023/24 are higher than the quantity of soybean oil used in these markets in 2021/22.

Comment:

One commenter stated that BBD production provides a good market for animal fats that do not have attractive export markets. This commenter stated that a relatively small percentage of animal fats are currently used to produce BBD, leaving opportunities for growth in the quantity of these feedstocks used for BBD production. The commenter also stated that investments are being made that would expand the production of animal fats.

Response:

We are aware that there are currently quantities of animal fats that are sold into non-biofuel markets that could be diverted to biofuel production. As discussed in Preamble Section VI.B, increasing biofuel production by diverting feedstocks from other uses could have negative market impacts and could result in an increase in the use of higher GHG feedstocks in non-biofuel markets. Our projections of available feedstocks reflect the ongoing investments to increase the production and availability of animal fats, and project that the production of BBD from these feedstocks will continue to increase in future years consistent with the observed trends over the past five years.

Comment:

A commenter stated that increased production of SAF would pull limited feedstocks away from biodiesel and renewable diesel production.

Response:

As discussed in Preamble Section III.B.2.b, renewable diesel and SAF are currently produced using the same feedstocks and very similar production technologies, and in most cases are produced at the same production facilities. Given the limitations on the available feedstocks for renewable diesel and SAF production we generally agree that future increases in SAF production through 2025 will likely result in less renewable diesel production than we would expect in the absence of increased SAF production.

Comment:

A commenter stated that EPA should not limit the advanced biofuel volume over concerns about palm oil backfilling because biodiesel and renewable diesel produced from palm oil cannot generate RINs or LCFS credits. The commenter also stated that parties are not currently investing to increase palm oil production.

Response:

The commenter correctly notes that renewable diesel from palm oil cannot generate advanced biofuel RINs or LCFS credits. However, higher RFS volume requirements than we are finalizing in this rule could result in the diversion of soybean oil, FOG and other qualifying feedstocks for biofuel production from non-biofuel markets in the U.S. or abroad. These non-biofuel markets are not subject to the RFS regulations. They would be expected to look for alternative sources of vegetable oil to replace the feedstocks diverted for biofuel production, and may choose to utilize palm oil or other non-qualifying vegetable oils if these are the lowest cost alternatives available in the market.

Comment:

A commenter supported EPA's statements in the proposed rule that renewable diesel production may be limited by available feedstocks in future years, and that increasing renewable diesel production may result in decreasing biodiesel production.

Response:

In this final rule we have projected the production and net imports of biodiesel and renewable diesel based on a projection of the growth in the available feedstocks used to produce these fuels in North America. We project that the production and net import of renewable diesel will increase significantly through 2025 while the production and net import of biodiesel will decline slightly through 2025, likely in response to competition for available feedstocks.

Comment:

A commenter stated that the biodiesel and renewable diesel capacity numbers do not account for potential feedstock limitations and production capacity should not be used as a basis for projecting biodiesel and renewable diesel production.

Response:

While we have considered biodiesel and renewable diesel production capacity in establishing the RFS volumes for 2023–2025, we project that the production of biodiesel and renewable diesel will be limited to a volume significantly below the total production capacity, primarily due to the availability of qualifying feedstocks to these facilities.

4.3 Imports and Exports of Biodiesel and Renewable Diesel

Comment:

A commenter stated that EPA presents inconsistent and inconclusive evidence about potential palm biodiesel and renewable diesel imports.

Response:

Historical data on the imports of grandfathered biodiesel and renewable diesel (which is assumed to be produced from palm oil) is presented in Preamble Section III.B.4.B. The total volume of imported grandfathered biodiesel and renewable diesel in the past has been small, with none of this fuel reported to have been imported since 2017. The concerns related the potential for the RFS program to incentivize palm oil production and imports, however, are not limited to imports of biofuels produced from palm oil. Instead, as discussed in RTC Section 4.2, the primary way that the RFS program could incentivize increased palm oil production is by diverting qualifying feedstocks, such as soybean oil and FOG, from existing markets in the U.S. or abroad to be used for biofuel production. These non-biofuel markets could then use increasing quantities of palm oil to replace the soybean oil or FOG diverted to biofuel markets. While this palm oil would not be directly used for biofuel production, increasing biofuel production could indirectly cause increasing production and/or imports of palm oil for use in other markets.

Comment:

A commenter stated that the 2022 volume requirements resulted in an 18% increase in the imports of BBD.

Response:

The commenter does not provide a citation for their statement that imports of BBD increased by 18% in 2022. According to data from EMTS there was very little change in BBD imports from 2021 (570 million gallons) to 2022 (568 million gallons). Regardless, the volume of BBD projected to be supplied to meet the RFS volumes we are finalizing in this rule are based on the projected increase in the production of BBD feedstocks in North America through 2025.

Comment:

A commenter stated that EIA data reveals that the U.S. has been importing 0.3–1.0 billion gallons of biodiesel and renewable diesel per year since 2013 to meet the ethanol portion of the RFS requirement.

Response:

In addition to corn ethanol, biodiesel and renewable diesel can and has been used to help meet the implied conventional biofuel portion of the total renewable fuel standard. According to EMTA data, imports of biodiesel and renewable diesel ranged from a low of 314 million gallons in 2014 to a high of 884 million gallons in 2016. Depending on the RIN type generated for this biodiesel, these imported fuels can and are used to help satisfy the BBD, advanced biofuel, and/or total renewable fuel obligations. We note that imported biofuels are not necessarily the marginal biofuel volumes. Therefore decreasing the volume requirements will not necessarily result in lower biofuel imports, and can instead cause lower domestic biofuel production.

4.4 Projected Rate of Production and Use of Biodiesel and Renewable Diesel

Many commenters focused their comments on the appropriate level of the BBD, advanced biofuel, and total renewable fuel volumes, rather than the projected rate of production of biodiesel and renewable diesel in 2023–2025. For a further discussion of comments related to the proposed volumes for BBD and advanced biofuel, see RTC Sections 6.1.2 and 6.1.3.

Comment:

Many commenters stated that EPA's projections of biodiesel and renewable diesel production and use in 2023–2025 were too low. Some of these commenters cited to projections of biodiesel and renewable diesel production and consumption from EIA's Short Term Energy Outlook (STEO) and/or Annual Energy Outlook (AEO) as support for their claims that EPA's projections were too low and recommended that EPA adopt the EIA projections. Some commenters stated that EIA projected an increase of 500–600 million gallons of renewable diesel production in 2023. One commenter cited projected increases in global BBD production by IEA as support for their clams that EPA's projections of biodiesel and renewable diesel production were too low.

Response:

Projections of biodiesel and renewable diesel consumption in the U.S. from EIA's May 2023 STEO and 2023 AEO, and EPA's projections in this final rule are shown in the table below.

Billion Gallons	2023	2024	2025
EIA May 2023 STEO	4.15	5.00	N/A
EIA 2023 AEO	3.99	4.60	4.60
EPA Projections	3.71	3.85	4.24

As noted by the commenters, EPA's projections are lower than the volumes of these fuels projected to be consumed in EIA's forecasts. EIA's forecasts, however, are not based on a full consideration of the statutory factors. For example, EIA does not consider the impacts on climate change, air quality, water quality, wildlife habitat, etc. when forecasting biodiesel and renewable consumption. We recognize that higher volumes of biodiesel and renewable diesel could be achieved in 2023–2025, primarily through the imports of additional feedstocks and/or biofuels, however we do not believe that our analysis of the statutory factors would support higher volumes than we are finalizing in this rule.

Comment:

Multiple commenters stated that the proposed BBD volumes are lower than the actual production and use of these fuels in 2022.

Similarly, multiple commenters stated that EPA's projections of biodiesel and renewable diesel production and use are lower than what is currently available and/or the growth potential for these fuels.

Response:

According to EMTS data, the actual volume of BBD supplied to the U.S. in 2022 was 3.12 billion gallons (4.96 billion RINs). This is significantly less than the volume of these fuels we project will be supplied to meet the RFS volumes we are finalizing in this rule (3.71–4.24 billion gallons; see RIA Table 3.1-4). As stated in the previous response, while we recognize that greater volumes of these fuels could be supplied in 2023–2025, primarily through greater imports of fuels and feedstocks and from additional diversion from other uses such as food, we do not believe it would be appropriate to require the use of greater volumes of BBD in 2023–2025.

Comment:

A commenter stated that EPA did not consider the projected rate of production and use of biodiesel and renewable diesel when determining the proposed volumes.

Response:

EPA assessed the projected rate of production and use of biodiesel and renewable diesel in 2023–2025. Our assessment of this factor can be found in RIA Chapter 6.2.6. The RFS volumes we are finalizing in this rule considered this factor, along with the other statutory factors. Our analysis of the statutory factors can be found in the RIA, and an explanation of our consideration of the statutory factors in determining the RFS volume requirements can be found in Preamble Section VI.

Comment:

Multiple commenters stated that EPA's projection of biodiesel and renewable diesel production should be closer to the projected production capacity for these fuels.

Response:

EPA considered the projected production capacity of biodiesel and renewable diesel. As discussed in RIA Chapter 6.2.2, actual production of biodiesel and renewable diesel has consistently fallen short of the available production capacity in the past. We project that this observed trend is likely to continue in 2023–2025, and that biodiesel and renewable diesel production will be limited to a volume below the production capacity for these fuels by other factors, such as the availability of qualifying feedstock. See RIA Chapter 6.2 for more information on our assessment of biodiesel and renewable diesel production and use in 2023–2025.

Comment:

A commenter stated that the Inflation Reduction Act will accelerate growth in advanced biofuel production.

Response:

We recognize that incentives outside of the RFS program, such as the incentives provided as part of the IRA, may accelerate growth in advanced biofuel production. At this time, however, we are unaware of any other advanced biofuels that are likely to be produced in commercial scale quantities by 2025 beyond the biodiesel, renewable diesel, and the other advanced biofuels discussed in RIA Chapters 6.3 and 6.4 that are already factored into our final volumes. The IRA may help provide economic support and therefore reduce RIN prices, but we do not anticipate that it will lead to greater volumes that we are finalizing. See these chapters for a discussion of the projected production and use of these other advanced biofuels.

Comment:

A commenter stated that renewable diesel is currently cannibalizing biodiesel production due to a lack of demand for biodiesel and renewable diesel and greater policy incentives for renewable diesel.

Response:

According to EMTS data the supply of biodiesel in the U.S. decreased in 2021 and 2022 (relative to the level supplied in 2020) as renewable diesel production increased. Within the context of the RFS program, the only additional incentive renewable diesel is provided over biodiesel is a higher equivalence value based on the higher energy content of renewable diesel on a per gallon basis. We continue to believe that basing equivalence values on the energy content of the fuel is appropriate, as fuels with higher energy content generally provide greater value as transportation fuel.

By statutory design, both biodiesel and renewable diesel can be used to meet the RFS standards. Historically the market has been dominated by biodiesel, but in recent years the market has been shifting to renewable diesel. The RFS volumes we are finalizing in the rule are expected to result in a significant increase in the demand for biodiesel and renewable diesel. Whether this increased production is met with biodiesel or renewable diesel will be the result of many different local, state, national, and international market factors, including the incentives provided by the RFS program and other state and federal incentives.

Comment:

A commenter stated that EPA should not project renewable diesel production from new facilities until they begin producing fuel. This commenter noted that these projects could be delayed or cancelled if there is not enough feedstock.

Response:

We recognize that the availability of feedstock is a key factor in the likely future production of biodiesel and renewable diesel. Our assessment of available feedstocks to biodiesel and renewable diesel producers, presented in RIA Chapter 6.2.3, is an important element of our projection of biodiesel and renewable diesel production and use, presented in RIA Chapter 6.2.6. We note, however, that the projected production capacity of renewable diesel through 2025 is significantly higher than the volume of renewable diesel we project will be produced. Thus, even if a number of the announced renewable diesel production facilities are delayed or cancelled we do not expect that production capacity will limit the overall production of renewable diesel through 2025.

Comment:

A commenter stated that BBD production may drop when the tax credit changes in 2025.

Response:

At this time there is significant uncertainty as to how the Clean Fuel Production Tax Credit, which replaces the biodiesel tax credit in 2025, will impact biodiesel and renewable diesel producers. While this change may impact the financial incentives available to biodiesel and renewable diesel producers, we do not expect that it will significantly impact the potential production and use of these fuels.

4.5 Carveout for Biodiesel from Renewable Diesel

Comment:

A commenter stated that EPA should establish a biomass-based diesel volume requirement of 2 billion gallons for 2024 and 2025 and should require that this volume be met with D4 RINs generated for biodiesel (rather than renewable diesel or other fuels). The commenter claimed that EPA could achieve this by requiring that the BBD volume requirement be met by D4 RINs with a fuel code of 20. According to the commenter this would not change the definition of BBD established by Congress but would only change how obligated parties comply with the required volumes. As an alternative, the commenter suggests EPA could require a certain percentage of the BBD obligation be met with biodiesel. The commenter argues that this would give meaning to the BBD volume requirement (which currently has no meaning since the advanced biofuel volume requirements are incentivizing BBD volumes above and beyond the BBD volume requirement), is consistent with the statutory structure, and would result in greater benefits relative to the current structure of the RFS program.

Response:

The changes to the RFS program requested by the commenter contradict the plain language of the Energy Independence and Security Act. 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.[14] 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.”[15] 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 biomass-based diesel 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 biomass-based diesel but are not eligible to satisfy an obligated party’s biomass-based diesel 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. Were EPA to consider changes to the RFS program as requested by the commenter, such changes should be formally

[14] CAA section 211(o)(1)(D).
[15] 40 USC §13220(f)(1).

proposed by EPA, with an opportunity for input from a broad ranges of stakeholders.

4.6 Other Comments on Biodiesel and Renewable Diesel

Comment:

A commenter stated that demand for BBD is dependent on the RFS volume requirements.

Response:

For the purposes of the analysis in this rule EPA developed a No RFS baseline, which represents the quantity of renewable fuels we project would be produced and used in the absence of the RFS program. We estimate that without the RFS program the volumes of BBD used in the U.S. would be significantly lower (to 1.7–2.1 billion gallons per year in 2023–2025) than the volumes of BBD we project will be used to meet the RFS volume requirements we are finalizing in this rule (3.7–4.2 billion gallons). BBD is therefore not totally dependent on the RFS program to create market demand, however the RFS volume requirements are a key factor.

Comment:

A commenter stated that the proposed volumes are not consistent with USDA's HBIIP, which will increase consumer access to biodiesel blends.

Response:

USDA's HBIIP provides funding for infrastructure to distribute and dispense higher level biofuel blends. At this time the use of biodiesel and renewable diesel is not limited by the ability to distribute these fuels or by consumer demand. Thus, while the HBIIP may increase consumer access to biodiesel and renewable diesel blends we do not expect that it will directly impact the production and use of these fuels in 2023–2025.

Comment:

A commenter stated that there is no evidence that excess volumes of advanced biodiesel and renewable diesel will be needed or used to meet the shortfall in conventional biofuel.

Response:

With the exception of 2020 and 2021 (which were established retro-actively) EPA has established the RFS volume requirements with an implied conventional biofuel volume of 15 billion gallons each year since 2017. Despite this, the supply of conventional biofuel has never reached 15 billion gallons. The maximum quantity of conventional biofuel supplied was 14.5 billion gallons in 2018, and the total volume of conventional biofuel supplied in 2022 was just over 14 billion gallons. This is despite the fact that D6 RIN prices have been relatively high (greater than $1 per RIN) since early 2021. Conversely, the supply of non-cellulosic advanced biofuel RINs supplied in 2022 (5.3 billion RINs) exceeded the implied volume requirement for these fuels (5.0 billion RINs). This historical RIN generation data, together with our assessments of the quantity of non-cellulosic advanced and conventional biofuels projected to be produced and used in 2023–2025 presented in RIA Chapter 6, provide solid evidence that excess volumes of non-cellulosic advanced biofuels, including advanced biodiesel and renewable diesel, will be needed and used to meet the shortfall in conventional biofuel.

Comment:

A commenter recognized that excess biodiesel and renewable diesel can be used to meet the total renewable fuel volume requirement, but states that other categories of renewable fuel (such as conventional renewable fuel) have lower RIN values than BBD and advanced biofuel. The commenter further stated that the implied conventional renewable fuel volume in the proposed rule did not increase through 2025, and therefore there would be no increased demand for biodiesel and renewable diesel from the total renewable fuel volume requirement.

Response:

Since early 2021 the RIN prices for advanced biofuel and BBD RINs have been approximately equal to the RIN prices for conventional biofuel RINs. Thus, the commenter's claim that conventional biofuel volumes have lower RIN values are not accurate. Further, even when BBD RINs are used to meet an obligated party's total renewable fuel obligation (rather than their BBD or advanced biofuel obligation) these RINs can and are still traded at the same value as other BBD RINs.

We acknowledge that the volume of implied conventional renewable fuel does not increase from 2023–2025 in this final rule. Nevertheless, there is some variation in the projected shortfall of the conventional renewable fuel supply relative to the implied conventional biofuel volume requirements of 15 billion gallons, with the shortfall generally increasing in future years. Even if this shortfall is not increasing, it does significantly increase the demand for non-ethanol biofuels, including biodiesel and renewable diesel, created by this final rule.

Comment:

A commenter stated that the proposed volumes are in conflict with the Administration's goals for increasing production of sustainable aviation fuel.

Response:

It is not clear what conflict the commenter believes exists. Sustainable aviation fuel (SAF) that is produced from renewable biomass (and used as jet fuel) qualifies under the RFS program just like other renewable fuels, including renewable diesel. The RFS program, including the volumes we are finalizing in this rule, continue to support significant increases in the production and use of advanced biofuels such as SAF. We project that this rule will result in an increase in the total supply of advanced biofuel of over 2.5 billion RINs of advanced biofuel in 2025 relative to the quantity of advanced biofuel supplied in 2022.

Comment:

A commenter stated that the RFS volume requirements should not disrupt food markets.

Response:

In this rule we have projected the growth in the production and use of biodiesel and renewable diesel based on the projected increase in the production of feedstocks used to produce these fuels in North America. In doing so we intend to avoid or minimize the diversion of vegetable oils and other potential BBD feedstocks from domestic food markets to biofuel production. We therefore do not project that the RFS volumes in this final rule will disrupt domestic food markets.

Comment:

A commenter stated that supplying vegetable oil to all new renewable diesel facilities would require 55-60 million new acres of soybeans. The commenter stated that increased demand for soybeans would displace other crops.

Response:

As discussed in RIA Chapter 6.2, we do not expect the total production of renewable diesel (and biodiesel) will match the total announced production capacity for all new and existing renewable diesel production facilities through 2025. Instead, we project that renewable diesel production will be limited by other factors, such as the availability of qualifying feedstocks. Further, nearly all of the projected feedstock growth in North America is projected to come from increases in the crushing capacity of soybeans and canola. Increasing soybean and canola crushing could result in reduced exports of soybeans and canola. Production of soybean and canola oil could therefore be achieved with little to no additional planting of these crops in the U.S. and Canada.

Comment:

A commenter stated that higher advanced biofuel volumes would not require new infrastructure.

Response:

We do not project that any additional infrastructure to distribute or use biodiesel or renewable diesel will be required to achieve the volumes in this final rule. Achieving these volumes will, however, require additional oilseed crushing capacity.

Comment:

A commenter stated that advanced biofuels cost more than conventional renewable fuels and will only be used if there are additional incentives for advanced biofuels.

Response:

In general, advanced biofuels do cost more than conventional renewable fuels to produce (see RIA Chapter 10). However, production costs do not represent all of the costs associated with a renewable fuel. Due to limits on the ability to consume conventional renewable fuels such as corn ethanol in some cases advanced biofuels can be competitive with conventional renewable fuels without additional incentives. Furthermore, due to blending economics and infrastructure limitations (e.g., retail stations) and the costs associated with upgrading the infrastructure, the costs of ethanol use at concentrations greater than E10 is considerably higher, making advanced biofuels more economically competitive.

Comment:

Multiple commenters stated that there is no blendwall for BBD. The ability to consume BBD will not limit the use of these fuels.

Response:

We do not expect that the ability to consume biodiesel and renewable diesel in biodiesel and renewable diesel blends will limit the production and use of these fuels through 2025.

Comment:

Higher advanced biofuel requirements would off-set tightness in the diesel market.

Response:

While this is conceptually true, we do not expect that the increases in the advanced biofuel requirement will have an appreciable impact on any tightness in the diesel market through 2025. Total diesel fuel consumption in the U.S. is projected to be approximately 52 billion gallons in 2025, and global diesel demand is over 380 billion gallons per year.[16] While increasing the supply of advanced biofuel directionally increases the total available supply of diesel fuel and diesel fuel blends, the impact is small, especially on a global scale. Furthermore, much of the new production of advanced biofuel is occurring at petroleum refineries that are shifting production from petroleum diesel to renewable diesel. In these situations increased renewable diesel production does not increase overall supply of diesel fuel.

Comment:

A commenter stated that EPA's administration of the RFS program advantages renewable diesel over biodiesel because renewable diesel has a higher equivalence value, is able to generate RINs for co-products, and allows RIN separation for renewable diesel producers (many of whom are obligated parties). The commenter further stated that an increasing reliance on renewable diesel inappropriately creates a "one state program" in California. The commenter claimed that the

[16] https://www.researchgate.net/figure/Consumption-of-gasoline-and-diesel-fuel-2000-2021-million-barrels-per-day_fig5_364216663

larger scale of renewable diesel producers would result in fewer BBD producers, which could result in reduced competition, market manipulation, and higher prices for BBD.

Response:

By statutory design, both biodiesel and renewable diesel can be used to meet the RFS standards. Historically the market has been dominated by biodiesel, but in recent years the market has been shifting to renewable diesel. Within the context of the RFS program, the only additional incentive renewable diesel is provided over biodiesel is a higher equivalence value based on the higher energy content of renewable diesel on a per gallon basis. We continue to believe that basing equivalence values on the energy content of the fuel is appropriate, as fuels with higher energy content generally provide greater value as transportation fuel. While it is true that in some cases renewable diesel producers can also generate RINs for some of their co-products such as naphtha, this is because unlike the co-products of biodiesel some of the co-products of renewable diesel are used as transportation fuel. The ability for renewable diesel producers to separate RINs is similarly not simply an advantage granted to renewable diesel producers but reflects that fact that renewable diesel can more readily be used as transportation fuel without blending with petroleum fuel. While it may be easier to blend increasing quantities of renewable diesel in California, thereby taking advantage of the opportunity to generate LCFS credits this is the result of regulations enacted by the state of California, not EPA.

Whether the increased production required of the final standards is met with biodiesel or renewable diesel will be the result of many different market factors, including the incentives provided by the RFS program and other state and federal incentives. In many instances, the economic advantages associated with a local feedstock supply and access to a local market would be expected to continue to support the production of biodiesel.

5. Ethanol

5.1 E10 Blendwall and Total Gasoline Demand

Comment:

The E10 blendwall is no longer a relevant point of reference. Due to the existence of E15 and E85, the average ethanol concentration is about 10.3%. Therefore, the “E10 blendwall” is really an “E10.3 blendwall.”

Response:

The E10 blendwall represents a simplified market scenario in which every gallon of gasoline consumed in the U.S. contains precisely 10% ethanol, and there is no E0, E15, or E85. Historically it has provided a helpful point of reference in the gasoline market’s transition first from E0 to E10,and more recently from E10 to higher ethanol blends such as E15 and E85. As shown in Figure 1.7-3, the poolwide ethanol concentration increased at a considerably faster rate through about 2011 when E0 was replaced by E10 than it did after 2011 when the primary means for increasing ethanol consumption was E15 and E85. The E10 blendwall remains a helpful point of reference in ascertaining the development of the gasoline market over time, especially since the vast majority of ethanol continues to be used as E10.

Nevertheless, we recognize that the poolwide ethanol concentration has indeed reached about 10.3% due to increasing sales of E15 and E85. As discussed in more detail in RIA Chapter 6.5, we have accounted for this higher poolwide ethanol concentration in our projection of total ethanol consumption for 2023–2025.

Comment:

EPA is inappropriately treating the E10 blendwall as an impediment to increasing ethanol consumption.

Response:

Other than as a helpful point of reference, we do not use the E10 blendwall to project the volumes of ethanol that we believe can be consumed in 2023–2025. Instead, we projected the total volume of ethanol that will be consumed in 2023–2025 in a way that accounts for growth in sales of E15 and E85. The net result is that total ethanol consumption is projected to exceed the E10 blendwall. See RIA Chapter 6.5 for details.

5.2 Exceeding the E10 Blendwall

Comment:

Stakeholders provided opposing views on whether higher volume requirements for conventional renewable fuel would result in higher consumption of E15 and/or E85. Some said that the higher RIN prices that result from higher volume requirements would increase sales of E15/E85, while others said that this would not occur, or only to a very small degree.

Response:

EPA believes that prospective RFS standards have some, albeit limited, ability to incentivize higher consumption of E15 and E85. The implied conventional biofuel volume in our rulemakings has been well above the E10 blendwall ever since 2013. This has kept D6 RIN prices high, providing a significant financial incentive for the growth of E15 and E85. Our final 2023–2025 standards are projected to be over one billion gallons over the E10 blendwall, thereby continuing this incentive for the growth of E15 and E85. The historical rise in the national poolwide ethanol concentration demonstrates that E15 and E85 growth has occurred. During 2016-2022, the nationwide average concentration of ethanol was above 10% and exhibited an increasing trend as shown in RIA Figure 1.7-3. Since the average ethanol concentration can exceed 10% only insofar as consumption of E15 and/or E85 more than offsets consumption of E0, the EIA data shows that consumption of those higher ethanol blends must generally have been increasing in those years.

However, the ability of the implied volume requirement for conventional renewable fuel to increase sales of E15 and/or E85 is also limited. A prior analysis of the impacts of E85 retail price discounts relative to E10 determined that sales volumes only increase moderately as that discount increases.[17] Finally, the market has found less expensive alternatives to comply with the implied conventional biofuel volume requirements, namely biodiesel and renewable diesel, which year after year has been counted on to backfill for the shortfall in E15 and E85 sales. As long as biodiesel and renewable diesel remain a more economical option for compliance, we anticipate that growth in ethanol use beyond the E10 blendwall will remain modest.

Note that, because the gasoline pool has been composed of nearly 100% E10 since at least 2016, higher RIN prices are unlikely to increase the amount of ethanol in the form of E10. The small amount that is E0 meets a niche demand for owners of recreational marine engines, nonroad engines, and others that are willing to pay a premium for it, and we believe that this demand will continue through at least 2025.

[17] "Updated correlation of E85 sales volumes with E85 price discount," available in the docket.

Comment:

Ethanol consumption can exceed the levels that EPA has projected if EPA sets the standards high enough. Higher standards lead to higher RIN prices, which in turn make E15 and E85 more economically attractive to consumers.

Response:

EPA believes that prospective RFS standards have some, albeit limited, ability to incentivize higher consumption of E15 and E85. While RIN prices have been high since 2013 (with the exception of slightly lower RIN prices in 2017 and 2018), there is no indication that they have had a significant impact on sales of E15 and E85. Nevertheless, the standards that we are setting for 2023–2025 include a significantly higher implied conventional renewable fuel volume requirement than the volume of ethanol consumption that we project will occur based on historical trends, As a result, there will be considerable opportunity for volumes of E15 and E85 to increase to meet the implied conventional renewable fuel volume requirement.

Comment:

A number of commenters argued that the 2023–2025 volume requirements should be set in such a way that the pool-wide ethanol content will not exceed the E10 blendwall. They based their preferred approach on the premise that E15 and E85 cannot contribute meaningfully to higher ethanol consumption.

Response:

As we said in previous annual standard-setting rules, we do not find the arguments that the pool-wide ethanol content cannot be higher than 10% to be compelling. As other commenters pointed out, the nationwide average ethanol concentration has been above 10.00% since 2016.

While we agree that use of E15 and E85 in 2023–2025 cannot enable the market to achieve 15.0 billion gallons of ethanol consumption, they can make meaningful contributions. This is reflected in our projections of increased total ethanol consumption, which inherently include volumes of E15 and E85, as discussed in RIA Chapter 6.5.

Comment:

Congress intended that ethanol consumption be limited to the E10 blendwall. As a result, setting standards that are higher than the blendwall is contrary to Congressional intent.

Response:

Neither of the statutes which established the RFS program (the Energy Policy Act of 2005 or the Energy Independence and Security Act of 2007) nor the Congressional record associated with those actions indicate that the E10 blendwall was intended to limit the applicable standards, nor has the commenter provided any evidence to support its assertion about Congressional intent. As discussed in previous annual standard-setting rulemakings, projections of gasoline demand at the time that these statutes were enacted did indicate an increasing future trend under which 15 billion gallons of ethanol could have been consumed as E10. While subsequent actions to increase the efficiency of gasoline vehicles reduced actual demand for gasoline such that 15 billion gallons of ethanol consumption was no longer possible with E10, this fact did not alter the volume targets specified by Congress in CAA 211(o)(2)(B) nor the statute's discretion to set volume requirements at appropriate levels under the available waiver authorities.

For years after 2022, the statute directs EPA to establish volume requirements based on an analysis of a number of specified factors, subject to several limitations. See preamble Section II. Those factors and limitations place no explicit restrictions on the volume of ethanol, nor on the implied volume requirement for conventional renewable fuel. Instead, EPA must determine appropriate volume requirements based on a consideration of the specified factors.

Comment:

The gasoline market is incapable of substantially exceeding a poolwide ethanol concentration of 10%. EPA admits that ethanol cannot help the RFS program grow.

Response:

As shown in RIA Figure 1.7-3, the nationwide average ethanol concentration has exceeded 10% since 2016. Regardless of whether those exceedances might be considered substantial, they are relevant in our assessment of the volume of ethanol that can be consumed. As discussed in more detail in RIA Chapter 6.5, we have combined historical trends on the nationwide average ethanol concentration with projections of retail offerings of E15 and E85 to project total ethanol consumption for 2023–2025. We are projecting increases in the nationwide average ethanol concentration through 2025.

We have considered all possible sources of renewable fuel in our determination of the appropriate volume requirements for 2023–2025. In the aggregate, the RFS program can grow beyond the 2022 levels in years after 2022.

Comment:

EPA has ignored other mid-level ethanol blends (E20–E50) in its assessment of the total volume of ethanol that can be consumed, even though these blends are sold and consumed by flex-fuel vehicles.

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 revenue collection process, and for 2022 it indicates that reported sales volumes of E20–E50 accounted for only 1% of all E15–E85 blends.[18] 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 2023–2025 does not have a meaningful impact on the results.

Our projection of total ethanol consumption for 2023–2025 is based on historical estimates of the nationwide average ethanol concentration and the number of retail service stations that offer E15 and E85. The ethanol concentration inherently includes ethanol sold as E20–E50 since it is calculated as total ethanol sold divided by total gasoline sold.

We are not aware of data on the number of retail service stations which offer E20–E50. However, we believe it is likely that such blends are sold at the same stations that offer E15 and/or E85. Thus, estimates of the number of service stations that offer E15 and E85 likely include stations that also carry E20–E50. Thus while we did not explicitly include E20–E50 in our analysis, ethanol sold as E20–E50 is accounted for.

Comment:

Only 13.9 billion gallons of ethanol can be consumed based on EIA’s gasoline demand projections, so it is unreasonable for EPA to say that more ethanol can be consumed.

Response:

Although the 13.9 billion gallons of ethanol consumption that we cited in the proposal is indeed based on EIA’s gasoline demand projections, it does not represent EIA’s projection of the amount of ethanol that will be consumed. Instead, it represents ethanol consumption as E10 based on their gasoline consumption projections. This is a theoretical scenario in which all gasoline contains 10% ethanol and there is no E0, E15, or E85. As described in RIA Chapter 6.5, we have projected that more ethanol than the E10 blendwall can be consumed in 2023–2025.

[18] “ 2022 Minnesota E85 + Mid-Blends Station Report,” available in the docket.

5.2.1 E15

Comment:

Some commenters pointed to the incompatibility of existing equipment at retail service stations for E15, while others said that most such equipment is in fact compatible with E15.

Response:

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.[19] 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 retailers' installed tanks are technically compatible with E15, the ability of those retailers 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. We further discuss infrastructure constraints on E15 use in RIA Chapter 7.5.3.

Comment:

One stakeholder said that there is insufficient distribution and retail infrastructure for E15 to make a meaningful contribution to the total volume of ethanol consumed.

Response:

In RIA Chapter 7.5.3, we discuss the constraints on E15 use related to distribution and retail infrastructure. E10 is already distributed nationwide, and many terminals have already announced that they have made adjustments needed to facilitate the blending of 15% instead of 10% ethanol.[20]

Overall, we do believe that E15 will make a meaningful, but relatively small, contribution to the total volume of ethanol used. Regardless, in determining the total volume of ethanol consumption, it was not necessary to estimate E15 volumes that might be used since we have used a correlation between the nationwide average ethanol concentration with the number of

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[19] See 40 CFR 280.32. This rulemaking does not reopen these regulations.

[20] Prime the Pump Update of E15 Stations. Email from Chris Bliley of Growth Energy, Jan 19, 2023. PowerPoint in Docket

stations offering E15 and E85 as discussed in RIA Chapter 6.5. This total ethanol consumption inherently includes ethanol from E15 in additional to ethanol from E10 and E85.

Comment:

One stakeholder said that even if existing underground storage tanks (UST) are compatible with E15, the various piping, fittings, and dispensing equipment may not be.

Response:

Retail station owners are not under any obligation to offer E15, and will do so only if they deem doing so to be of some advantage. In making the decision about whether to offer E15, they will consider all the changes that they may need to make to their equipment. Insofar as their existing USTs can be demonstrated to be compatible with E15, or if they already have underground storage systems capable of storing E85 that could then be used to provide E15 through blender pumps, the costs associated with the remaining requisite equipment changes may be correspondingly lower. We acknowledge that in some cases even if existing USTs are compatible with E15, the various piping, fittings, and dispensing equipment may not be, and that this would result in relatively higher costs for a retailer to make its equipment compatible with E15.

Comment:

One stakeholder said that EPA's projections of the number of retail stations offering E15 through 2025 would require growth at an unprecedented rate.

Response:

RIA Chapter 7.5.3 provides a detailed description of the methodology used to project the number of retail stations offering E15 in 2023–2025. The commenter provided no critique of that methodology.

Our methodology for projecting the number of retail stations offering E15 includes a linear extrapolation of retail stations that use funds from private sources and from the ethanol industry's Prime the Pump program. This linear extrapolation means that this category of growth is no different in the 2023–2025 timeframe than it was in the past.

The methodology also takes into account expected federal grant funds for expansion of infrastructure. These federal grants, most notably those under USDA's Higher Blends Infrastructure Incentive Program (HBIIP) and its predecessor the Biofuels Infrastructure Partnership, are expected to result in a higher rate of growth in stations offering E15 than in the past.

Comment:

One commenter said that only a quarter of all motor vehicles on the road are warranted by the manufacturer to operate on E15.

Response:

As described in the final rule which approved the use of E15 in model year 2001 and later vehicles,[21] EPA assessed the impact of E15 in four areas:

1. Exhaust emissions—immediate and long-term (known as durability);
2. Evaporative emissions—immediate and long-term;
3. The impact of materials compatibility on emissions; and
4. The impact of drivability and operability on emissions.

EPA determined that the use of E15 in model year 2001 and newer vehicles would not jeopardize those vehicle's ability to comply with applicable emission standards, and EPA did not anticipate any issues with regard to materials compatibility, drivability, or operability of the vehicles. As a result, EPA determined that it was appropriate to approve Growth Energy's application for a waiver submitted under section 211(f)(4) of the Clean Air Act, allowing fuel and fuel additive manufacturers to introduce into commerce gasoline that contains greater than 10 volume percent ethanol and no more than 15 volume percent ethanol (E15) for use in model year 2001 and newer light-duty motor vehicles.

While not all vehicles may be explicitly warranted by the manufacturer to use E15, the number that are warranted is considerably higher than that needed to consume the E15 volumes estimated in this final rule. As discussed in RIA Chapter 6.5.2, E15 consumption would represent less than 1% of all gasoline, far less than all the gasoline consumed by model year 2001 and later vehicles which are warranted to operate on E15.

[21] 76 FR 4662 (January 26, 2021).

5.2.2 E85

Comment:

One stakeholder said that E85 use did not increase substantially in the past because EPA had not set the standards high enough to incentivize it.

Response:

The RFS standards have provided incentives for increased use of E85 in the past and are expected to continuing doing so. However, as we explain above, increases in E85 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. However, commenters provided no new analysis of the E85 price discount that would occur under the influence of higher RFS volume requirements. As discussed in RTC Section 9.1.3 and RIA Chapter 1.9.2, 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 only slowly since 2012.

Thus while higher RFS standards may directionally incentivize higher E85 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. As we explain in RIA Chapters 6.2 and 6.5, we expect the latter to occur in 2023–2025.

Comment:

One stakeholder said that the projections of E85 sales volumes that EPA included in the proposal would be unprecedented.

Response:

The E85 sales volume projections included in the proposal for 2023–2025 would be higher than actual levels in the past. This is to be expected because the number of retail stations offering E85 continues to increase. However, those volume projections represented only moderate increases from past levels, and thus should not properly be labelled as unprecedented. E85 sales volumes have likely exceeded 300 million gallons per year in the past[22], and our most recent estimates indicate that sales volumes could be between 300 and 400 million gallons in 2023–2025 (see RIA Chapter 6.5.2). Given that the past and projected future E85 sales volumes are of the same order of magnitude, and both are much lower than the E85 consumption capacity of all FFVs, we continue to believe that the projections are reasonable. Regardless, we did not use projections of E85 (or E15) sales volumes in the determination of the applicable standards to set for 2023–

[22] See, for instance, "Estimate of E85 consumption in 2020," available in the docket.

2025. Instead, we projected total ethanol consumption based on historical trends in the nationwide average ethanol concentration in gasoline. See RIA Chapter 6.5.1.

Comment:

One stakeholder said that, according to data on E85prices.com, E85 is less expensive than E10, so E85 would be consumed even without the RFS program.

Response:

The commenter apparently ignores the much lower energy content of ethanol and its impact on fuel economy. We believe it is unlikely that E85 would be consumed at more than de minimis levels without the RFS program. As discussed in RIA Chapter 2.1.1, the economic analysis that we performed for the No RFS baseline assumes that essentially all E15 and E85 would cease to be consumed if the RFS program were to disappear. RINs would no longer exist, and thus could not provide the additional incentive that ethanol needs to make E85 more economically attractive than E10.

5.3 Sugarcane Ethanol Imports

Comment:

One stakeholder said that EPA should not be setting the advanced standard in such a way as to incentivize imports of Brazillian sugarcane ethanol since its GHG performance is no better than for corn ethanol.

Response:

According to EPA's assessment of the lifecycle GHG performance of imported sugarcane ethanol, it meets the 50% GHG reduction threshold needed in order to qualify as advanced biofuel.[23] As a result, sugarcane ethanol can be used to meet the applicable standard for advanced biofuel. However, EPA is not setting the advanced biofuel standard to incentivize any specific advanced biofuel. The standard is not specific to sugarcane ethanol, but instead can be met with any combination of qualifying advanced ethanol, biodiesel, renewable diesel, renewable gasoline, jet fuel, heating oil, naphtha, liquified petroleum gas (LPG), compressed natural gas (CNG), or electricity. The standards we are establishing for 2023–2025 take into account the projected availability of all qualifying advanced biofuels, in addition to analyzing the various economic and environmental factors required under the statute.

[23] 75 FR 14677 (March 26, 2010).

5.4 Projected Rate of Production and Use of Domestic Ethanol

Comment:

One stakeholder said that EPA's correlation between percent ethanol concentration and the number of retail stations offering E15 or E85 could be improved by including dummy variables for exempted volumes from small refineries.

Response:

We do not believe that the use of dummy variables to represent small refinery exemptions (SRE) would meaningfully affect the correlation. Given the magnitude of the total renewable fuel standard, despite the granting of SREs, the demand for conventional renewable fuel was not reduced below the E10 blendwall, and D6 RIN prices remained high. As a result, the RFS standards continued to create an incentive for retailers to sell, and for consumers to buy, E15 and E85 in those years when SREs were granted. We are not aware of any evidence that the number of SREs granted or the corresponding exempted volumes resulted in a decrease in total ethanol consumption below what would have occurred if those SREs had not been granted. On the contrary, the average ethanol concentration continued to increase during those years when SRE grants were highest, namely 2017–2019.

Moreover, even if SREs had some impact on the volume of ethanol actually consumed in comparison to the volume of ethanol that may have been consumed if those exemptions had not been granted, SREs had essentially no impact on the relationship between actual consumption of ethanol and the nationwide average ethanol concentration. That is, if no SREs had been granted, both the total volume of ethanol consumed and the concentration of ethanol in gasoline would have been higher, and the correlation between the two would have remained essentially the same.

Comment:

One stakeholder said that retail station counts for stations offering E85 that are available on E85prices.com are more accurate than those from AFDC, and are higher.

Response:

While E85prices.com is a decentralized system consisting of voluntary submissions from motorists, the data from the Alternative Fuels Data Center (AFDC) is based on a centralized system under which the data is regularly verified to be accurate, and stations no longer offering E85 are eliminated from the station count. As a result, we believe that station counts from AFDC are likely to be more accurate than those from E85prices.com.

Comment:

One stakeholder said that the projection of nationwide average ethanol concentration was based on too little data, and that EPA should instead assume that the ethanol concentration in 2023–2025 will be the same as recent levels.

Response:

As shown in RIA Figure 1.7-3, the nationwide average concentration of ethanol in gasoline has continued to increase over time, including in recent years. This trend is consistent with the trends for increasing offerings of E15 and E85 at retail service stations as shown in Figures 7.5.2-2 and 7.5.3-2, which we expect will continue into the future. Based on these observations, we do not believe it would be appropriate to assume that the nationwide average ethanol concentration does not increase for years after 2022.

One indicator of insufficient data would be a high degree of uncertainty in attempts to identify a correlation between two sets of data. However, the correlation between the nationwide average ethanol concentration and the number of stations offering E15 and E85 that is discussed in RIA Chapter 6.5.1 was relatively strong and had very low uncertainty. For instance, the r squared value was 0.967, indicating that the curve fit very closely followed the trend in the underlying data. In addition, the independent variables representing the number of stations offering E15 and E85 had p-values of 0.073 and 0.025, respectively, indicating statistical significance at the 90% confidence level.[24] Therefore, we do not believe that there was insufficient data to correlate the nationwide average ethanol concentration with E15 and E85 station counts.

Comment:

One stakeholder said that in projecting the consumption of ethanol for 2023–2025, EPA should account for the influence of the RFS program standards on that consumption.

Response:

As discussed in RIA Chapter 2.1.1, it is clear that in the absence of the RFS program ethanol consumption would be lower. More specifically, consumption of E15 and E85 would drop to nearly zero, while consumption of E10 would be largely unaffected. Thus the RFS program does provide incentive for the consumption of higher ethanol blends. However, we are not aware of a robust methodology for quantifying the impact of the RFS standards on ethanol consumption, and no stakeholder has presented such a methodology.

For the purposes of analyzing the impacts of the candidate volumes, we projected a volume of ethanol consumption that we believe is reasonably representative of what could occur in the 2023–2025 timeframe under the influence of the RFS program. This projection includes some growth in the use of E15 and E85, something that we believe would be unlikely if the RFS program were to cease to exist. More importantly, we are establishing an implied volume requirement for conventional renewable fuel for all three years that is significantly higher than the volume of ethanol consumption that we project will occur, even under the influence of the applicable standards. 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 create a significant incentive for higher volumes of ethanol consumption than we have projected if the market so chooses. Also, because we are establishing

[24] Note that the independent variable for E15 station counts actually used in the regression analysis was the natural log of station counts.

volume requirements for 2023–2025 that exceed the volume of ethanol that we project can be consumed, a higher consumption volume of ethanol than we have projected will merely result in less BBD being needed to meet the implied volume requirement for conventional renewable fuel.

5.5 Methodology for Projecting Consumption of Ethanol

Comment:

One stakeholder said that consumption is not among the statutory factors that EPA must consider, and that consideration of constraints on consumption of ethanol are contrary to the market-forcing purposes of the RFS program.

Response:

As discussed in the prologue to RIA Chapter 6, 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.

The RFS program was indeed intended by Congress to drive consumption of renewable fuel above the levels that would have occurred in the absence of the program. As discussed in RIA Chapter 2.1.1, the program does indeed do this for ethanol. Moreover, we are establishing an implied volume requirement for conventional renewable fuel for all three years that is significantly higher than the volume of ethanol consumption that we project will occur. 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:

One stakeholder said that EPA inappropriately based its projection of ethanol consumption on historical data and disregarded the potential for increases in per-station sales volumes of E15 and E85.

Response:

The use of historical data to make future projections is a common methodology, and avoids the much more uncertain approach of basing projections on theoretical outcomes uninformed by actual history. In fact our methodology for projecting total ethanol consumption for 2023–2025 uses a combination of historical data and expectations for growth in the number of retail stations offering E15 and E85. See RIA Chapter 6.5.1 for details.

We note that we have not used per-station sales volumes of E15 and E85 to project the total volume of ethanol that may be consumed in 2023–2025. Instead, we correlated historical nationwide average ethanol concentration with the number of retail service stations offering E15 and E85. However, for cost purposes only, we did make projections of E15 and E85 sales volumes. See RIA Chapter 6.5.2. In this context, the proposal used estimated per-station sales volumes derived from 2019 data collected by USDA in its Biofuels Infrastructure Partnership

(BIP) program. For this final rule, we obtained additional data from USDA from the BIP program and have determined that both the E15 and E85 sales volumes do change over time. As a result, we have accounted for these changing per-station sales volumes in our future projections of E15 and E85 consumption.

6. Proposed Volumes

6.1 Proposed Volumes for 2023–2025

6.1.1 Proposed Cellulosic Biofuel Volumes

Several commenters that provided comments on the cellulosic biofuel volume for 2023–2025 also commented on EPA projection of cellulosic biofuel production in these years and the methodology used to project cellulosic biofuel production. Responses to these comments can be found in RTC Section 3.

Comment:

A commenter stated that EPA should set high cellulosic biofuel volume requirements that are not expected to be met and should offer cellulosic waiver credits for sale to obligated parties to enable compliance with the cellulosic biofuel volume requirements.

Response:

The statute requires that EPA set the applicable cellulosic biofuel requirement "based on the assumption that the Administrator will not need to issue a waiver . . . under [CAA section 211(o)](7)(D)" for the years in which EPA sets the applicable volume requirement.[25] See Preamble Section II.C.2 for a further discussion of this issue.

Comment:

Multiple commenters stated that the cellulosic biofuel volumes should be increased to reflect a higher growth rate for CNG/LNG derived from biogas. One commenter characterized a higher growth rate for CNG/LNG derived from biogas as more realistic. Another commenter stated that the proposed volumes do not account for the potential increases in biogas produced from digesters, which could be significant. Other commenters requested that EPA use the growth rate requested by the coalition for renewable natural gas (at least 30%) to project the production of CNG/LNG derived from biogas.

Response:

In this final rule we have increased our projections considerably of CNG/LNG derived from biogas. The volumes in this rule are calculated using a growth rate of 25% per year over 2022 levels. For a further discussion of our projections of the production of CNG/LNG derived from biogas, see RTC Section 3.2.2 and RIA Chapter 6.1.3.

[25] CAA section 211(o)(2)(B)(iv).

Comment:

A commenter stated that EPA's final volumes should reflect the fact that the production and use of non-food-based biofuels are much lower than anticipated by Congress.

Response:

The cellulosic biofuel volumes we are finalizing in this rule are significantly higher than the volumes achieved in previous years. These volumes are still well short of the 16 billion gallon statutory target established by Congress for cellulosic biofuel for 2022, reflecting the lower production of these fuels than anticipated by Congress when EISA was passed in 2007.

Comment:

A commenter stated that EPA should finalize more stringent volume requirements for cellulosic biofuel. Other commenters similarly stated that the cellulosic volumes must be increased to avoid significant reductions in the cellulosic (D3) RIN price, which could negatively impact investment in cellulosic biofuel production, and that EPA must dramatically increase the cellulosic biofuel volumes to address the inherent over-supply of cellulosic biofuel.

Response:

We have increased the required volumes of cellulosic biofuel for 2023–2025 relative to the proposed volumes (after accounting for the fact that we are not finalizing regulatory provisions for eRINs in this rule). The volumes we are finalizing are not to achieve some predetermined RIN price, but rather reflect our careful consideration of the statutory factors after using our best efforts to project the candidate volumes in 2023–2025 that will be available, reflecting the projected growth based on historical increases as a result of the incentives provided by the RFS program, . We believe the final cellulosic volumes appropriately address concerns that the proposed volumes might have resulted in an over-supply of cellulosic biofuel RINs which could have negatively impacted the market for cellulosic biofuel and cellulosic biofuel RINs. For more information on our projections of cellulosic biofuel production see RTC Section 3 and RIA Chapter 6.1. For more information about our consideration of the statutory factors see Preamble Section VI.

Comment:

Multiple commenters stated that the cellulosic biofuel volumes should be increased to account for ethanol production from corn kernel fiber. One commenter suggested that the volumes should be increased by up to 250 million gallons per year to account for this fuel.

Response:

In this final rule we have increased the candidate cellulosic biofuel volumes for 2023–2025 to account for the projected production of ethanol produced from corn kernel fiber. Our projections of this fuel are described further in RIA Chapter 6.1.2 and RTC Section 3.2.1. We finalized cellulosic biofuel volumes in accordance with our statutory requirements. For more information about our consideration of the statutory factors see Preamble Section VI.

Comment:

Multiple commenters stated that the cellulosic biofuel volumes should not be increased.

Another commenter stated that EPA should be cautious when setting the cellulosic biofuel volumes, especially for 2023, since there are little or no cellulosic carryover RINs available and because cellulosic waiver credits will not be available to obligated parties. This commenter also stated that EPA should be prepared to use the waiver authorities to reduced volumes if necessary.

Response:

As stated in Preamble Section VI.A, our analyses of all of the statutory factors indicates that the benefits of higher volumes of cellulosic biofuel outweigh the potential negative impacts. We therefore believe that to realize the benefits associated with increasing cellulosic biofuel production it is reasonable to establish cellulosic biofuel volume requirements through 2025 at the candidate level that reflects the projected growth in cellulosic biofuel production from 2023–2025 based on the available data. Our projections of cellulosic biofuel production and use in 2023–2025 in this final rule are higher than our projections in the proposed rule (after accounting for the fact that we have not finalized regulatory provisions for eRINs). For more information about our consideration of the statutory factors see Preamble Section VI. For further discussion of our projections of cellulosic biofuel production and use, see RTC Section 3.1 and RIA Chapter 6.1.

Assuming the market is able to achieve these volumes, as we currently project, then cellulosic carryover RINs should not be needed. We do not anticipate that we will need to use the cellulosic waiver authority, or any other waiver authority, to reduce the cellulosic biofuel volumes we are establishing in this rule. We therefore do not expect that cellulosic waiver credits will be available to obligated parties, however we note that we do retain the authority to reduce the required cellulosic biofuel volumes if the statutory criteria for future waivers are met. If we were to reduce the cellulosic biofuel volumes we are establishing in this final rule using our cellulosic waiver authority, we would make cellulosic waiver credits available to obligated parties, consistent with the statutory provisions for this waiver authority.

Comment:

A commenter stated that the cellulosic volumes should only include fuels produced from waste feedstocks.

Response:

We project that the cellulosic biofuel volumes we are establishing in this final rule will be met with CNG/LNG derived from biogas and ethanol produced from corn kernel fiber. As the commenter acknowledges in their comment, CNG/LNG derived from biogas is produced from waste feedstocks. While corn kernel fiber is not necessarily a waste feedstock, it is a low value by-product of corn ethanol production. Thus, the cellulosic biofuel volumes we are finalizing are consistent with this commenter's request. Nevertheless, the statute does not restrict cellulosic biofuels to those derived only from wastes, so non-waste feedstocks could be used now or in the future.[26]

Comment:

Multiple commenters stated that the cellulosic volumes should be set at the maximum achievable level. One commenter stated that setting volumes at the maximum achievable level would be consistent with Congressional intent that the RFS program is intended to be a market-forcing program.

Response:

The volumes we are finalizing reflect our consideration of the statutory factors. As explained in Preamble Section IV, we identified candidate volumes using our best efforts to project the growth in the volume of these fuels that can be achieved in 2023–2025 based on the available data. We recognize that it is possible that cellulosic biofuel production may exceed the volumes we are establishing in this rule, and therefore these volumes do not necessarily represent the maximum achievable volumes. Nevertheless, the final cellulosic volumes are based on our assessment of the statutory factors and reflect our intent to provide continued support for cellulosic biofuel production and to establish cellulosic biofuel volumes consistent with the statutory direction to establish the cellulosic biofuel volumes at a level not expected to require us in the future to lower the applicable cellulosic volume requirement using the cellulosic waiver authority under CAA section 211(o)(7)(D).[27]

Comment:

A commenter stated that the cellulosic biofuel volumes should account for second-generation ethanol production in Brazil.

Response:

As discussed in RIA Chapter 6.1, the U.S. has not imported cellulosic ethanol from Brazil in several years. Because of the lack of imports of this fuel in recent years and our expectations that there will be strong demand for second-generation ethanol in Brazil we have not included any of this fuel in our projections of cellulosic biofuel production and imports in 2023–2025.

Comment:

A commenter stated that EPA's assessment of the statutory factors was insufficient. This commenter claimed that that EPA did not consider the statutory factors in determining the

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[26] CAA section 211(o)(1)(E).
[27] The cellulosic biofuel waiver applies when the projected volume of cellulosic biofuel production is less than the minimum applicable volume. CAA section 211(o)(7)(D).

proposed cellulosic biofuel volumes, and instead simply set the volumes at the volumes EPA projected would be produced.

Response:

EPA did not ignore the statutory factors in establishing the cellulosic biofuel volumes in this final rule. Instead, as discussed in Preamble Section VI.A, our assessment of the statutory factors led us to conclude that the benefits of higher volumes of cellulosic biofuel outweigh the potential negative impacts. The impact of cellulosic biofuel production is discussed in greater detail throughout the RIA. We therefore believe that to realize the benefits associated with increasing cellulosic biofuel production it is reasonable to establish cellulosic biofuel volume requirements through 2025 at the level that reflects the projected growth in cellulosic biofuel production from 2023–2025 based on the available data. Thus, while the cellulosic biofuel volumes we are establishing in this final rule are equal to the volume of these fuels we project will be produced or imported into the U.S. in 2023–2025, our decision to establish these volumes is based on our consideration of the analysis of the statutory factors.

We do not believe our assessment of the statutory factors would support establishing cellulosic biofuel volumes that are lower than the projected production and import of cellulosic biofuels. This would likely result in decreased production of cellulosic biofuel, and we would expect fewer of the benefits associated with the production and use of cellulosic biofuels relative to the volumes we are establishing in this rule. Conversely, we do not believe our assessment of the statutory factors would support establishing cellulosic biofuel volumes that are higher than the projected production and import of cellulosic biofuels. We do not expect that higher volume requirements would result in any additional production or imports of cellulosic biofuels. Thus, these higher volumes would potentially result in increased fuel price impacts and potential regulatory uncertainty without any of the benefits associated with increased cellulosic biofuel production and use.

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:

Cellulosic biofuel is not limited to cellulosic ethanol. In this final rule we are projecting the production of cellulosic ethanol from corn kernel fiber (7 million, 51 million, and 77 million gallons in 2023–2025, respectively). See RIA Chapter 6.1 for more detail on our projections of cellulosic ethanol production from CKF. Moreover, we do not believe that it would be appropriate to establish cellulosic biofuel volume requirements based solely on the projected production of cellulosic ethanol when we expect that other qualifying cellulosic biofuels will be produced in 2023–2025.

6.1.2 Proposed BBD Volumes

Comment:

EPA should set the BBD standard at the statutory minimum of 1 billion gallons. Doing so will maximize compliance flexibility and thus reduce costs. The advanced standard will still create the demand for BBD.

Response:

Setting the BBD standard at 1 billion gallons would represent a dramatic departure from the levels that we proposed. Although we did request comment on "other options" for the BBD standard in the proposal, we did not propose nor request comment on setting the BBD standard for any of the years 2023, 2024, or 2025 at 1 billion gallons. As a result, we do not believe that we could establish such a requirement in this action. Even so, we do not believe that it would be appropriate to do so at this time.

We are establishing BBD standards for 2023, 2024, and 2025 which ensure that there will continue to be about 600–700 million RINs worth of advanced biofuel which is not required to be BBD. At the same time, we believe that BBD will be the primary form of advanced biofuel used because other, non-BBD forms of advanced biofuel have been and are expected to continue to be very small. Thus, we expect that there would be little if any material difference in the actual supply of BBD if the BBD standard were reduced to 1 billion gallons, and thus effectively no impact on compliance flexibility. Moreover, finalizing BBD volume requirements at levels which exceed the 2022 volume requirement of 2.76 billion gallons helps to ensure that the necessary volumes will be produced.

Comment:

Multiple commenters stated that the proposed BBD volumes do not reflect the projected increase in renewable diesel production capacity or the investment in BBD feedstock production.

Response:

EPA considered the projected production capacity of biodiesel and renewable diesel. As discussed in RTC Section 4 and RIA Chapter 6.2.2, actual production of biodiesel and renewable diesel has consistently fallen short of the available production capacity. We project that this observed trend is likely to continue in 2023–2025, and that biodiesel and renewable diesel production will be limited to a volume below the production capacity for these fuels by other factors, such as the availability of qualifying feedstock.

In this final rule we have updated our assessment of available feedstocks for biodiesel and renewable diesel production. Our updated projections account for expected increases in soybean oil production in the U.S. and increased canola oil production in Canada due to recent investments in oilseed crushing capacity. See RTC Section 4 and RIA Chapter 6.2 for more information on our assessment of biodiesel and renewable diesel production and use in 2023–2025.

Comment:

Multiple commenters stated that the BBD volumes should be higher to provide support for the BBD industry. Others claimed that the BBD volumes should be higher to reflect the existing and projected demand for BBD, or to reflect projected production of BBD. Many of these commenters requested that EPA increase the required BBD volumes by 500 million gallons each year.

A commenter stated that the proposed volumes would not incentivize growth in BBD production.

Response:

As discussed in RTC Section 4 and RIA Chapter 6.2, EPA has established advanced biofuel volumes and total renewable fuel standard volumes that are expected to result in an increase in the use of advanced biodiesel and renewable diesel by nearly 2 billion ethanol equivalent gallons by 2025. The final standards thus provide a considerable incentive for the growth of BBD. However, as discussed in Preamble Section VI.C, our approach to determining the specific BBD volume requirement is consistent with our policy in previous annual rules, where we also set the BBD volume requirement in concert with the change, if any, in the implied non-cellulosic advanced biofuel volume requirement. In reviewing the implementation of the RFS program to date, we determined that this approach successfully balanced a desire to provide support for BBD producers with an increasing guaranteed market, while at the same time maintaining an opportunity for other advanced biofuels to compete within the advanced biofuel category. We project that the advanced biofuel and total renewable fuel volume requirements will incentivize the production and use of significantly greater volumes of biodiesel and renewable diesel than is required by the BBD standards. See Preamble Section VI for a further discussion of our consideration of the BBD volume requirements in the broader context of all the volume requirements we are finalizing in this rule.

Comment:

Multiple commenters noted that EIA projects higher volumes of BBD production than the BBD volumes proposed by EPA. Some of these commenters requested that EPA set the BBD volume requirements equal to EIA’s projections of BBD production (or consumption), with some claiming that EPA had set the BBD volume at the levels projected by EIA in previous rules.

Multiple commenters stated that the proposed volumes for BBD for 2023–2025 were lower than current BBD production. Some of these commenters claimed that the actual supply of BBD exceeded 3 billion gallons in both 2021 and 2022, while other commenters claimed the actual supply in 2022 was 3.6 billion gallons.

Another commenter stated that the BBD volume requirement should be increased to achievable levels based on up-to-date information.

Response:

EPA has never established the BBD volume at the levels projected by EIA. Since 2013, when EPA first set the required volume for BBD based on our analysis of the statutory factors in CAA section 211(o)(2)(B)(ii), we have always established the BBD volume at a level that was lower than the quantity of BBD we projected would be produced and used to meet the other renewable fuel standards. We have taken the same approach in this rulemaking. This approach has provided ongoing incentives for increased production of BBD, while also preserving market opportunity for other advanced biofuels within the RFS program. From 2013 to 2022 BBD use has increased from 1.65 billion gallons to 3.12 billion gallons, and the volume of BBD supplied exceeded the BBD volume requirement each year, with the exception of years where the BBD volume requirements were set retroactively. These data demonstrate that our approach to establishing the BBD volume requirements can and does provide significant incentives for the increased production and use of BBD. We project that the volumes we are finalizing in this rule will continue to incentivize growth in the production and use of BBD (see RIA Table 3.1-3).

Comment:

A commenter stated that the BBD required volumes should reflect the investments made by USDA to increase biodiesel and renewable diesel consumption.

Response:

USDA's HBIIP provides funding for infrastructure to distribute and dispense higher level biofuel blends. At this time the use of biodiesel and renewable diesel is not limited by the ability to distribute these fuels or by consumer demand. Thus, while the HBIIP may increase consumer access to biodiesel and renewable diesel blends we do not expect that it will directly impact the production and use of these fuels in 2023–2025.

Comment:

A commenter requested that the BBD volumes for 2023–2025 be set at 2021 levels (2.34 billion gallons) in light of the uncertainty related to the availability of feedstocks and the climate risks associated with the potential to incentivize increased palm oil production. Other commenters similarly requested that EPA not increase the BBD volume requirements, and consider decreasing the required volumes.

Response:

As discussed further in RTC Section 4 and RIA Chapter 6.2, we project that the increase in BBD production and use incentivized by the volume requirements in this rule will primarily be supplied by fuels produced from increased soybean oil and canola oil production in the U.S. and Canada (with lesser volumes from FOG and distillers corn oil based on historical trends) and not imports of palm oil. 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.

Comment:

A commenter stated that small biodiesel producers and small soybean crushing facilities would be at risk if EPA does not increase the BBD volumes. Another commenter similarly stated that if the BBD volumes in the final rule were not increased then competition from renewable diesel and sustainable aviation fuel producers would drive small biodiesel producers out of business.

Response:

We project that the volumes we are finalizing in this rule will result in significant increases in the quantity of BBD used, from 3.1 billion gallons in 2022 to over 4.2 billion gallons in 2025. This projected increase in demand for BBD should benefit BBD producers (including biodiesel producers) and feedstocks suppliers of all sizes. Whether this increased production is met with biodiesel or renewable diesel will be the result of many different market factors, including local market factors in addition to the incentives provided by the RFS program and other state and federal incentives.

Comment:

A commenter stated that the proposed BBD volumes jeopardize the Administration's goals for the production of sustainable aviation fuel (SAF). Another commenter stated that EPA should establish higher BBD volumes in the final rule to support all forms and uses of BBD, including BBD used as heating oil.

Response:

As noted in the previous response, we project that the volumes we are finalizing in this rule will result in significant increases in the quantity of BBD used, from 3.1 billion gallons in 2022 to over 4.2 billion gallons in 2025. While historically nearly all the BBD used in the U.S. has been biodiesel or renewable diesel, the RFS program provides incentives for all forms of BBD, including SAF and fuels used as heating oil. We expect that the volumes we are finalizing in this rule will continue to provide incentives for the production and use of all types of BBD, including SAF and heating oil.

Comment:

A commenter stated that the proposed volumes for BBD were disappointing following the strong support for BBD in the 2020–2022 RFS rule.

Response:

The volume requirements we are finalizing in this rule are expected to provide continued strong support for the increasing production and use of BBD. The use of BBD increased significantly in

2020–2022, from approximately 2.46 billion gallons to 3.12 billion gallons, due in part to the incentives provided by the 2020–2022 RFS rule. This increase represents an annual increase of approximately 330 million gallons per year. We project that the use of BBD in the U.S. will increase from 3.1 billion gallons to over 4.2 billion gallons from 2022–2025 to satisfy the volume requirements we are establishing in this final rule. This represents a growth rate of approximately 370 million gallons per year, which is higher than the observed BBD growth rate from 2020–2022.

Comment:

A commenter stated that the BBD volumes were too low and were inappropriately limited based only on the potential for the diversion of feedstocks, ignoring the other statutory factors.

Another commenter stated that the BBD volumes should be reduced dramatically and should only include fuels projected to be produced from waste feedstocks.

Response:

The volume requirements we are finalizing in this rule, including the BBD volume requirements, are based on our analysis of the statutory factors. As discussed in Preamble Section VI.B, while we recognize that BBD volumes may be possible beyond those we project will be supplied to meet the volume requirements in this rule, these fuels have relatively high costs, and greater volumes of BBD are more likely to have reduced GHG benefits and other negative environmental impacts. Conversely, while limiting the BBD volume requirements to only fuels produced from waste feedstocks may minimize the potential negative environmental impacts, lower BBD volumes would result in fewer energy security benefits, lower domestic employment in the biofuels industry and reduced income for biofuel feedstock producers. We also believe that the production and use of BBD may achieve the greatest benefits with the fewest negative impacts when increased production is consistent with increased production of qualifying feedstocks produced in North America, as we have done in this final rule.

Comment:

A commenter supported EPA's proposed BBD volumes and supported minimizing the BBD volume requirements to allow other advanced biofuels to compete for market share. Another commenter similarly claimed that EPA should set the BBD volumes for 2023–2025 at the minimum volume allowed by the statute (1 billion gallons), and that biodiesel and renewable diesel beyond this level should have to compete with other advanced biofuels.

Response:

In this final rule we are maintaining our practice from previous RFS rules of increasing the BBD volume requirements in concert with increases in the implied non-cellulosic advanced biofuel volume requirements. In reviewing the implementation of the RFS program to date we determined that this approach successfully balanced a desire to provide support for BBD producers with an increasing guaranteed market, while at the same time maintaining an opportunity for other advanced biofuels to compete within the advanced biofuel category.

6.1.3 Proposed Advanced Biofuel Volumes

Comment:

A number of different companies have announced plans to convert existing facilities or build new facilities to produce advanced renewable diesel and sustainable aviation fuel. Nevertheless, EPA is proposing to only increase advanced volumes by 100 million gallons per year. The annual increase should be much higher.

Response:

We are aware that a number of companies have announced their intentions to initiate projects that, if completed, would significantly increase the domestic production capacity of renewable diesel and sustainable aviation fuel. However, a key issue going forward is the availability of feedstock supply to support this new production capacity in addition to the existing biodiesel production and food consumption. The volume requirements for BBD and advanced biofuel are therefore not simply estimates of the maximum production capacity of BBD and advanced biofuel. Instead, the volume requirements consider the impact on all of the statutory factors, including the impact of the volumes on the price and supply of agricultural commodities such as vegetable oil and the impact on food prices. CAA section 211(o)(2)(B)(ii)(VI). We believe that the final volume requirements reflect an appropriate consideration of the statutory factors.

Comment:

Several commenters pointed to our conclusion that a substantial volume of excess advanced biodiesel and renewable diesel would be used to fill the shortfall in consumption of conventional ethanol in comparison to the proposed implied volume requirement of 15.25 billion gallons, and said that EPA should instead shift that shortfall in projected consumption of conventional ethanol from the implied conventional renewable fuel volume requirement to the advanced biofuel volume requirement. This would leave the total volume requirement unchanged but would align the projected availability of each type of renewable fuel more directly with their corresponding standards. These commenters generally claimed that this change would increase GHG emission reductions and benefit obligated parties through lower D6 RIN prices since the implied conventional volume would be below the E10 blendwall.

Response:

In the final rule EPA has partially taken the approach advocated for by these commenters. We have reduced the implied conventional biofuel volume from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifted the 0.25 billion gallon difference to the advanced biofuel standard. However, this volume is still in excess of that anticipated to be met with conventional biofuels. While we anticipate that greater volumes of advanced biofuel will be used than required by the advanced biofuel standards in 2023–2025, we do not believe it is appropriate to increase the advanced biofuel volume by shifting a portion of the implied conventional renewable fuel volume requirement to the advanced biofuel volume requirement.

Neither the statute nor the regulations require that only conventional renewable fuel (renewable fuel identified with a D code of 6) be used to fulfill the implied volume requirement for conventional renewable fuel. Indeed, the implied volume requirement for conventional renewable fuel is not a requirement per se, but instead is only a description of that portion of the total volume requirement which is not required to be advanced biofuel. Any portion of the implied volume requirement for conventional renewable fuel can be met with advanced biofuel. Because additional volumes of advanced biofuel will be used to satisfy the total standard, we expect that the positive impacts of increased advanced biofuel production mentioned by many commenters will still be realized by the final standards. This includes potential impacts on climate change and energy security as highlighted by some commenters.

In addition, by not shifting the shortfall in corn ethanol to the advanced biofuel volume requirement as commenters suggested, we have maximized the flexibility obligated parties have in complying with the implied volume requirement for conventional renewable fuel. Obligated parties can comply with the effective 15.25 billion gallon implied volume requirement in 2023 (including the 2023 supplemental standard) and the 15.0 billion gallon implied volume requirement in 2024 and 2025 with a combination of RINs representing corn ethanol and RINs representing excess advanced biofuel, or they can seek out non-ethanol conventional renewable fuel. Were we to shift the shortfall in corn ethanol to the advanced biofuel volume requirement, obligated parties would not have this option.

While making such a shift might have the impact of lowering D6 RIN prices for obligated parties, as a commenter suggested, lower D6 RIN prices would reduce the incentives for higher level ethanol blends, as well as the incentives for other non-ethanol conventional biofuels. We recognize that lower D6 RIN prices would reduce the cost of purchasing RINs for obligated parties, but we note that we have concluded that obligated parties recover the cost of the RINs they acquire in the sales price for the petroleum-based fuels they produce (see RTC Sections 9.1.3 and 9.1.9 for a further discussion of the impact of the RFS program on refiners).

Comment:

One commenter stated that the 2023–2025 advanced biofuel volume should be no higher than the volume of advanced biofuels used in 2022 to ensure the supply of vegetable oil to other markets including food. Higher volumes could result in food shortages.

Response:

EPA’s assessment of available feedstocks concluded that projected growth in feedstock supply over time should be sufficient to produce the higher volumes of biodiesel and renewable diesel we project will be used to meet the renewable fuel standards we are establishing in this rule and to satisfy demand in other markets. By 2025 in particular, we project increased production of vegetable oil from increased crushing of soybeans in the U.S. and imports of canola oil from Canada. More information on our assessment of feedstock availability can be found in RTC Section 4.2 and RIA Chapter 6.2.3.

Comment:

EPA should increase the advanced biofuel volume to incentivize the production of advanced biofuels other than BBD. The proposed volume requirements for advanced biofuel leave no room for growth in non-BBD advanced biofuels.

Response:

Contrary to the comment, as in previous years the volume requirements we are establishing in this final rule will continue to create significant opportunities for advanced biofuels other than BBD. The opportunity for non-BBD advanced biofuels to participate in the RFS program is driven by the difference between the volume requirement for BBD and the implied volume requirement for non-cellulosic advanced biofuel. This difference is undifferentiated advanced biofuel, meaning that any type of advanced biofuel can be used to meet it. In this final rule, this difference is approximately 600 million RINs each year for years 2023, 2024, and 2025, respectively. These differences are far larger than the volumes of non-BBD advanced biofuel that have been produced and consumed in the past as shown in RIA Table 6.4-1.

Comment:

One stakeholder said that EPA should project the production of sustainable aviation fuels (SAF) in 2023–2025 and should include these fuels in the required advanced biofuel volume. Another stakeholder said that the advanced biofuel volume requirements should be higher than the proposed levels to support SAF, consistent with other federal measures promoting SAF.

Response:

The implied volume requirement for non-cellulosic advanced biofuel increases over the 2023–2025 timeframe. This increase creates an opportunity for all forms of advanced biofuel, including SAF.

Furthermore, EPA has considered SAF in our projections of renewable fuel production for 2023–2025. SAF is listed as jet fuel in RIA Table 3.1-3. We note that at present SAF is competing with the same feedstock supplies as biodiesel and renewable diesel, and therefore does not represent an opportunity for increased volumes of non-cellulosic advanced biofuel growth. Regardless, development of SAF has been slow in recent years, and SAF use only reached 14 million gallons in 2022. We will continue to monitor developments in sustainable aviation fuel production and anticipate including this renewable fuel in future projections as warranted.

Comment:

One stakeholder said that higher volumes of SAF would result in lower volumes of renewable diesel.

Response:

SAF as currently produced is a portion of the distillate fuel that is otherwise produced and sold as renewable diesel. A portion of the distillate fuel produced is in the distillation range of jet fuel range and separated and sold separately as SAF. However, if this added step is not taken, the product continues to be sold as renewable diesel. Thus, increasing SAF production in 2023–2025 would likely be offset by lower renewable diesel production, rather than increasing overall BBD or advanced biofuel production (which include qualifying SAF).

Comment:

Several stakeholders said that the advanced biofuel volume requirement should be based on an assessment of expected domestic production and reasonable growth, and that all projected advanced biofuel supply should be included in the advanced biofuel volume requirement rather than a portion being included in the implied volume requirement for conventional renewable fuel.

Response:

Generally, stakeholders providing these comments were focused on the non-cellulosic portion of the advanced biofuel volume requirement. Our assessment of the total volume of non-cellulosic advanced biofuel that can be reasonably achieved in 2023–2025 under the influence of the RFS program, and which formed the basis for the candidate volumes discussed in Preamble Section III.C and RIA Chapter 3, was based on a consideration of all supply-related factors. These included domestic production capacity, feedstock supply, imports and exports of renewable fuel and feedstocks, and the necessary infrastructure to distribute, blend, dispense, and consume renewable fuel. Moreover, our assessment of feedstock supply included an assessment of crushing capacity for crop-based feedstocks such as soybeans and canola. For non-cellulosic advanced biofuel, these assessments are described primarily in RIA Chapters 6.2 through 6.4.

The volume requirements that we are finalizing in this action are based in part on our assessment of expected domestic production and reasonable growth in non-cellulosic advanced biofuel, just as these stakeholders requested. Other factors relevant to supply of non-cellulosic advanced biofuel include the potential for diversion of domestic feedstocks from other uses to advanced biofuel production and the attendant market disruptions that could occur, and the uncertainty associated with foreign markets for feedstocks and renewable fuels. Finally, we also 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.

Supply-related factors are not the only relevant considerations. As provided in CAA section

211(o)(2)(B)(ii), EPA must analyze a number of factors in the process of making a determination of the appropriate volume requirements for years without statutory volumes, and this statutory provision includes a number of other economic and environmental factors in addition to renewable fuel supply. These include impacts on the “cost to consumers of transportation fuel” and “food prices”, and the potential environmental impacts such as land use changes for crop-based feedstocks, among others. As a result of the consideration of all statutory factors, we have established volume requirements that we believe achieve the broad goal of the RFS program to increase the use of renewable fuels in the transportation sector over time while also balancing the various economic, environmental, and market implications.

Comment:

Several stakeholders said that EPA should prioritize advanced biofuels over conventional renewable fuel.

Response:

Aside from cellulosic biofuel, advanced biofuel is dominated by biodiesel and renewable diesel which are blended into diesel fuel. Conventional renewable fuel, in contrast, is dominated by corn ethanol which is blended into gasoline. Moreover, the feedstocks for non-cellulosic advanced biofuel and conventional renewable fuel are largely independent: conventional ethanol is produced from corn, whereas biodiesel and renewable diesel are produced from soy and canola oil in addition to other non-crop-based feedstocks. In the context of assessing the volumes of these fuels that may be appropriate to require, and in light of the broad RFS program goal of increasing the total volumes of renewable fuel used in the transportation sector over time, we can treat them more or less independently.

Stakeholder comments related to shifting a portion of the implied conventional renewable fuel volume requirement to the advanced biofuel volume requirement are addressed in RTC Section 6.2.2.

Comment:

Several stakeholders said that the proposed non-cellulosic advanced biofuel volume requirements for 2023–2025 are below actual historical supply of these fuels, so the proposal is actually going backwards.

Response:

The largest historical consumption volume for non-cellulosic advanced biofuel occurred in 2022, reaching 5,275 million RINs.[28] This volume includes not only BBD, but also imported sugarcane ethanol, domestic advanced ethanol, and renewable diesel produced by co-processing biomass with petroleum, naphtha, heating oil, and non-cellulosic biogas. More importantly, this volume includes that used in fulfillment of the 2022 advanced biofuel volume requirement and also that

[28] “RIN supply as of 3-7-23,” available in the docket.

used in fulfillment of the implied volume requirement for conventional renewable fuel.

While we proposed that the implied volume requirement for non-cellulosic advanced biofuel would be 5,100 million RINs in 2023 and 5,200 million RINs in 2024, and these proposed levels would appear to be lower than actual consumption of non-cellulosic advanced biofuel in 2022, this comparison is erroneous. Our proposal also projected that substantial volumes of BBD would be supplied in excess of that needed to meet the advanced biofuel volume requirement. Specifically, our proposal assumed that an additional 700–800 million RINs would be needed in 2023–2025 to help meet the implied conventional renewable fuel volume requirement of 15.25 billion gallons. Taking into consideration new projections of gasoline consumption and the reduction in the implied conventional volume requirement to 15.0 billion gallons in 2024 and 2025, this volume has increased to approximately 1.0–1.2 billion RINs for the final rule. Thus, the total volume of non-cellulosic advanced biofuel that we projected would be needed to meet the proposed volume requirements in each year from 2023 through 2025 would far exceed actual consumption in 2022. However, we believe these volumes are achievable by the market (See RIA Chapter 6.2 for our projection of BBD production use in 2023–2025).

Comment:

Several stakeholders said that the advanced biofuel volume requirement should account for future increases in naphtha, non-cellulosic biogas, and other advanced biofuels.

Response:

We discuss our investigation into advanced biofuels other than BBD and present our methodology for projecting future consumption volumes in RIA Chapter 6.4. In short, the available data does not provide any indication of a consistent increasing trend over time. As a result, we have implemented a methodology for projecting future consumption volumes of other advanced biofuel that weights historical consumption volumes according to how recently they occurred. This methodology permits us to make a projection of consumption volumes for 2023–2025 despite the absence of a trend in historical consumption volumes. We note, however, that this methodology results in the same projected consumption volume for all three years.

Comment:

Several stakeholders said that the advanced biofuel volume requirements should be set at the maximum achievable levels.

Response:

The statute does not require that EPA to set volume requirements at the maximum achievable levels. CAA section 211(o)(2)(B)(ii) states that EPA must determine the applicable volume requirements “based on a review of the implementation of the program during calendar years specified in the tables, and an analysis of” a set of specified factors. Additionally, CAA section 211(o)(2)(B)(iii) requires the percentage of advanced biofuel in relation to the total renewable fuel category be at least the same percentage as it was in 2022. We are setting the advanced biofuel standards in accordance with our statutory requirements. See also responses to comments in RTC Section 2.1.1.

Comment:

Some stakeholders said that the advanced biofuel volume requirements should be higher than those we proposed, but provided no specific numerical suggestions. Other stakeholders did provide numerical suggestions, though with considerable variety. These ranged from 250 million gallons above the proposed 2023 level to 8 billion RINs by 2025, with many suggestions for other levels between these extremes. One stakeholder said that the advanced biofuel volume requirements should reflect EIA projections of biodiesel and renewable diesel production and production capacity, and cited EIA's Short-Term Energy Outlook as projecting that production would reach 3.8 billion gallons in 2023 and 4.66 billion gallons in 2024, and that that renewable diesel capacity alone could reach 5.9 billion gallons by 2025.

Response:

Although some stakeholders did not distinguish between advanced biofuel and the non-cellulosic portion of advanced biofuel in discussing the higher volume requirements that they believed should be set, by context we interpreted their comments as referring to non-cellulosic advanced biofuel based on their focus on advanced biodiesel and renewable diesel. Also, some stakeholders did not clearly distinguish between ethanol-equivalent gallons (RINs) and physical gallons in their suggested numerical volume targets.

In making numerical suggestions for higher levels of non-cellulosic advanced biofuel, essentially all stakeholders ignored the volumes of BBD that we projected would be needed to help meet the proposed volume requirement for conventional renewable fuel of 15.25 billion gallons. This substantial volume—amounting to over a billion RINs per year—represents BBD that the market would supply but which is not reflected in the volume requirement for advanced biofuel. Accounting for this additional volume of BBD means that the demand for non-cellulosic advanced biofuel actually meets or exceeds the higher levels that some stakeholders said should be required.

Additionally, the higher volume requirements that many stakeholders suggested were implicitly based on the maximum achievable levels, typically linked to total possible production capacity. As discussed in a previous response, we are not required under the statute to target the maximum achievable levels, and indeed the statute directs EPA to analyze a variety of specified factors in determining the appropriate volume requirements for years without statutory volumes.

In determining the proposed volume requirements for non-cellulosic advanced biofuel, we thoroughly analyzed all of the factors that stakeholders mistakenly said we had not properly accounted for, specifically feedstock supply and associated oilseed crushing capacity, and BBD production capacity. We have updated those analyses with more recent data for this final rule, and our assessment of these and other factors related to BBD supply is described in RIA Chapter 6.2. However, unlike most stakeholders, we also analyzed other economic and environmental factors as required under the statute. Our final implied volume requirements for non-cellulosic advanced biofuel for 2023–2025, as for all other categories of renewable fuel, were based on a consideration of all of the factors that we must consider under the statute, not only those related to supply.

Comment:

Several stakeholders said that the proposed volume requirements for advanced biofuel were too high and should be reduced, for a variety of different reasons:

- Future production capacity for renewable diesel was too uncertain
- The Administration has targeted 100% electric vehicles (EVs) by 2050 in its Blueprint for Transportation Decarbonization, and increasing volumes for advanced biofuel conflict with this goal
- Non-food-based feedstocks are much lower than anticipated by Congress
- Increasing non-cellulosic advanced biofuel increases land conversion for soybeans which is prohibited under CAA 211(o)(1)(I)(i)

Response:

As discussed in RIA Chapter 6.2.2, renewable diesel production capacity has been increasing for several years, and is projected to continue increasing through 2025. This increase in renewable diesel production capacity has likely been impacted by a number of different programs that offer incentives of the production and/or use of renewable diesel such as the RFS program, California's Low Carbon Fuel Standard program, and the federal biodiesel tax credit. Also, the short timeframe between release of this final rule and the last year for which we are establishing standards (2025) means that most construction projects should be underway now in order to be able to produce renewable diesel in 2025. These considerations significantly reduces the uncertainty for our projections of renewable diesel production capacity through 2025. See also responses to comments in RTC Section 4.1.

While the Blueprint for Transportation Decarbonization has a goal of net-zero GHG emissions from the transportation sector by 2050, EVs are not the only avenue through which this goal is expected to be achieved. Sustainable liquid fuels are also expected to play a role.[29] Moreover, the gasoline and diesel demand projections from EIA that we use to evaluate the volumes of liquid biofuels that can be consumed and to calculate the applicable percentage standards account for increasing sales of EVs.[30] Finally, we do not believe that the volume requirements we are establishing in this action for the three year period 2023–2025 in any way conflict with the considerably longer term goal of decarbonization of the transportation sector by 2050.

The primary feedstocks used to produce qualifying renewable fuel that can also be used for food or animal feed are corn, soybeans, and canola. Non-food based feedstocks include waste oils, fats, and greases, biogas, crop residue, separated food waste, and yard waste, among others. There is nothing in CAA 211(o) which explicitly addresses non-food-based feedstocks for the production of renewable fuel other than to permit their use, and there is essentially nothing in the

[29] "Fact sheet - National Blueprint for Transportation Decarbonization," available in the docket.
[30] EIA Annual Energy Outlook 2023.

Congressional record on this topic. It is therefore difficult to know Congress' intentions or expectations with regard to non-food-based feedstocks. It is true that the volume targets specified in the statute include an implied volume target for conventional renewable fuel that is fixed at 15 billion gallons for 2015–2022, suggesting that Congress intended growth in renewable fuel consumption after 2015 to be through advanced biofuels. It is also true that conventional renewable fuel is composed primarily of ethanol produced from corn. However, these facts provide no insight into Congress' expectations regarding potential supply of non-food-based feedstocks. In our determination of the appropriate implied volume requirements to establish for non-cellulosic advanced biofuel, we have analyzed and projected the availability of all types of feedstocks, including both food-based and non-food-based feedstocks. This is consistent with the statute's list of qualifying feedstocks under the definition of renewable biomass at CAA 211(o)(1)(I) and with our obligation to analyze the supply of agricultural commodities and the expected annual rate of future commercial production of renewable fuels under CAA 211(o)(2)(B)(ii).

With regard to the land conversion implications of increasing the implied volume requirement for non-cellulosic advanced biofuel, we note that in compliance with the land use restrictions in CAA 211(o)(1)(I)(i), EPA established the aggregate compliance provision in the 2010 final rule.[31] 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 soybeans or canola may be used to produce biodiesel or renewable diesel in the 2023–2025 timeframe in comparison to previous years, the aggregate compliance provision ensures that the additional soybeans or canola cannot result in a net increase in the conversion of non-cropland to cropland.

Comment:

Several stakeholders said that the proposed volume requirements for advanced biofuel were too low, and would threaten small biodiesel producers. The smallest companies lose out when total demand is below total production capacity.

Response:

Like all standards, the advanced biofuel standard under the RFS program does not distinguish between different types of renewable fuel. Any qualifying renewable fuel that is made from renewable biomass and has an approved RIN-generating pathway with a D code of 3, 4, 5, or 7 can be used to comply with the advanced biofuel standard. In determining the appropriate volume requirements for advanced biofuel for 2023–2025, we consider all qualifying advanced biofuels, including biodiesel. Our consideration of production capacity for advanced biodiesel, renewable diesel, and jet fuel was tempered by our consideration of the availability of feedstocks. As discussed in RIA Chapter 6.2, limitations in the availability of feedstocks were a more constraining factor than production capacity. Moreover, as described in a previous response, we have taken into account not only supply-related factors such as production capacity and feedstock supply in making a determination of the appropriate volume requirements for advanced biofuel for 2023–2025, but have also considered other factors as required by the statute. We note that total demand for advanced biofuel will exceed that required by the

[31] 75 FR 14701 (March 26, 2010).

advanced biofuel volume requirement due to the need for additional volumes to help meet the implied volume requirement for conventional renewable fuel.

Once the standards are set it is up to the market to determine which RINs and biofuel types to use to meet each individual company's obligations. Renewable fuel producers of different sizes producing a wide variety of fuels from a wide variety of feedstocks will compete in the marketplace to supply the RINs needed by the obligated parties to comply. See also RTC Section 9.1.8.

Comment:

Several stakeholders said that the advanced biofuel volume requirements should be set in a way that creates incentives for further investment in production.

Response:

Although EPA retains the authority to waive volumes under the provisions of CAA 211(o)(7) under certain circumstances, it is not our intention to set standards in this action with the expectation that they will need to be waived in the future. Instead, we are establishing standards that we believe can be met based on projections of supply that can occur under the influence of the RFS program, and which are appropriate to establish after considering all of the other factors that we are required to consider under CAA 211(o)(2)(B)(ii). Nevertheless, we are mindful that the broad goal of the RFS program is to increase the use of renewable fuels in the transportation sector over time. We believe that the advanced biofuel volume requirements that we are setting in this action for 2023–2025 are consistent with this broad goal.

Comment:

One stakeholder said that the uncertainty in projecting renewable electricity for 2024 and 2025 threatens BBD. If the actual number of eRINs exceeds that which is needed to meet the cellulosic biofuel standard, the excess eRINs will be used to meet the advanced biofuel standard, pushing out BBD. Therefore, EPA should set the advanced biofuel standard as high as possible to avoid this outcome.

Response:

We are not finalizing the eRIN program in this action. Therefore, the comment provided by this stakeholder as specifically related to eRINs is moot.

EPA addresses general comments related to our projections of cellulosic volumes in RTC Section 3. EPA addresses other comments on the BBD volumes for 2024 and 2025 above.

Comment:

One stakeholder said that the proposed volume requirements for advanced biofuel are too low because they do not include advanced biofuel from biointermediates.

Response:

Our identification of the advanced biofuel candidate volumes reflect our evaluation of all likely sources of advanced biofuel in 2023–2025. The commenter does not provide data or information that quantifies potential advanced biofuel volumes from biointermediates in 2023–2025, and we do not anticipate that there would be appreciable volumes utilizing the recently finalized biointermediate regulations in this time period. To date, we have not registered any party for the production or use of a biointermediate and most parties that have indicated interest in producing or using biointermediates are at an early stage of development.

Comment:

One stakeholder said that the proposed increases in advanced biofuel for 2023–2025 were much lower than those that were established in 2022, calling into question the Administration's support for advanced biofuel.

Response:

The non-cellulosic portion of advanced biofuel increased by 510 million gallons from 2021 to 2022 in the action establishing standards for 2020–2022.[32] In comparison, we proposed increases of 100 million gallons each year for 2023–2025, which are lower annual increases than what occurred from 2021 to 2022. After further analysis and consideration of the comments we received, we have determined that it would be appropriate to increase the implied volume requirement for non-cellulosic advanced biofuel for 2024 and 2025 in comparison to the proposal. The volume requirements that we are establishing for 2023–2025 are based on the statutory factors that we are required to analyze under CAA section 211(o)(2)(B)(ii).

While the average annual increase in the implied requirement for non-cellulosic advanced biofuel is smaller for 2023–2025 than for 2020–2022, the actual volume of these fuels we expect will be used to meet the RFS volume requirements is greater in this rule. The use of non-cellulosic advanced biofuel increased from approximately 4.13 billion RINs in 2020 to 5.28 billion RINs in 2022. This increase represents an annual increase of approximately 580 million RINs per year. We project that the use of non-cellulosic advanced biofuel in the U.S. will increase from 5.28 billion RINs to 7.17 billion RINs from 2022–2025 to satisfy the volume requirements we are establishing in this final rule. This represents a growth rate of approximately 630 million RINs per year, which is higher than the observed non-cellulosic advanced biofuel growth rate from 2020–2022.

Comment:

One stakeholder requested that the volume requirements for advanced biofuel be set higher than the proposed levels in order to increase GHG reductions and jobs.

[32] 87 FR 39600 (July 1, 2022).

Response:

Climate change and job creation are two of the factors that we are required to analyze under CAA 211(o)(2)(B)(ii), and we address them in RIA Chapters 4.2 and 8.1, respectively. While increasing the volume requirements for advanced biofuel may provide benefits in these areas, we are also required to consider all of the statutory factors. Consideration of other economic and environmental factors under the statute tilt in favor of limiting increases of advanced biofuel. On balance, after a consideration of all factors, we have determined that the final volume requirements for advanced biofuel in this final rule are appropriate.

Comment:

One stakeholder requested that the volume requirements for advanced biofuel be set higher than the proposed levels in order to support the BBD industry. Another stakeholder said that EPA should support the use of heating oil in the northeast U.S. which also counts as BBD.

Response:

The broad goal of the RFS program is to increase the use of renewable fuels in the transportation sector over time, and this broad goal inherently includes support to the biofuel production industry. For years without statutory volumes, this broad goal must be met within the context of a consideration of various economic and environmental factors specified in CAA 211(o)(2)(B)(ii). Consideration of some of these factors are more directly related to support for the biofuel production industry, such as the expected annual rate of future commercial production of renewable fuels and job creation. These factors are discussed in RIA Chapters 6 and 8.1, respectively. After considering all statutory factors, we believe that the advanced biofuel volume requirements that we are establishing for 2023–2025 in this action comport with our statutory requirements and also provide support to the BBD industry .

Comment:

Several stakeholders said that, in the event that E15 consumption is higher in 2023–2025 than EPA has projected it will be, EPA should increase the advanced biofuel volume requirements to ensure that higher ethanol consumption does not result in lower consumption of advanced biofuel.

Response:

For the purposes of analyzing the statutory factors, we projected a volume of ethanol that we believe could be consumed in 2023–2025. This ethanol volume was not based on a projection of E15 consumption specifically but instead on a projection of the poolwide ethanol concentration coupled with projected gasoline demand from EIA (see RIA Chapter 6.5); this projection assumes that consumption and E15/E85 will increase. We believe it is unlikely that actual consumption of E15/E85 will significantly exceed those inherent in the total ethanol consumption volumes that we have projected for 2023–2025.

Comment:

One stakeholder said that since EPA has demonstrated that 15.25 billion gallons of conventional renewable fuel is achievable, EPA should not reduce the implied volume requirement for conventional renewable fuel in order to increase the advanced biofuel volume requirement.

Response:

In the proposal we requested comment on an alternative approach of reducing the implied conventional renewable fuel volume to 15.0 billion gallons as well as to below the E10 blendwall with no change in the volume requirement for total renewable fuel. In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifted the 0.25 billion gallon difference to the advanced biofuel standard. Given that we anticipate that additional advanced biofuel will be used to make up for the expected shortfall in conventional biofuel volume needed to meet the implied 15.0 billion gallons, we do not anticipate that this change will have any impact on the volumes actually used to comply with the standards. See also responses to comment in RTC Section 6.2.2.

Comment:

One stakeholder said that EPA must set the advanced biofuel volume requirement in a way that appropriately reflects expected growth so that increases in advanced biofuel do not displace conventional renewable fuel.

Response:

We have conducted an in-depth analysis of production capacity and feedstock availability for non-cellulosic advanced biofuel, with a particular focus on BBD. See RIA Chapter 6.2. However, the required volume requirements for non-cellulosic advanced biofuel were also based on a consideration of the other economic and environmental factors that we are required to analyze under CAA 211(o)(2)(B)(ii).

While we believe that the volumes requirements we are establishing in this final rule reasonably represent the volumes that can and will occur in the market for 2023–2025, it is possible that the market may respond to those volume requirements differently than we project. The RFS program is designed to operate this way, and it would be inappropriate for us to establish volume requirements that constrain the market's flexibility in determining the best way to comply.

Comment:

One stakeholder expressed concern that the shortfall in corn ethanol compared to the proposed 15.25 billion gallon implied volume requirement for conventional renewable fuel would increase demand and prices for vegetable oils.

Response:

As required under CAA 211(o)(2)(B)(ii)(VI), we have analyzed the impacts of the volumes on the price and supply of agricultural commodities, including vegetable oils. See RIA Chapters 8.3 and 8.4. Our assessment included impacts of expected market reactions to the candidate volumes for both non-cellulosic advanced biofuel and conventional renewable fuel. In this context, we included all vegetable oils used to produce advanced biofuel regardless of whether that advanced biofuel was consumed in fulfillment of the advanced biofuel volume requirement or the implied volume requirement for conventional renewable fuel. We have determined that the final volume requirements we are establishing in this action may result in some increase in the demand for and price of vegetable oils, but that those increases are acceptable in light of our overall assessment of the statutory factors.

Comment:

One stakeholder said that if EPA does not increase the volume requirements for advanced biofuel above the proposed levels, the RFS program will be out of step with various tax subsidies and the Inflation Reduction Act.

Response:

We are aware of a number of different tax subsidies, grants, and other financial incentives at both the federal and state level that could make renewable fuels more attractive or more available in the 2023–2025 timeframe. Insofar as they are relevant and their impacts quantifiable, we have taken them into account in our cost estimates. However, we note that the volume requirements we are establishing in this final rule are based on an assessment of the factors required by the statute, not only an assessment of supply and cost.

6.1.4 Proposed Total Renewable Fuel Volumes

This section includes comments related to the implied conventional renewable fuel volume requirement (that portion of the total renewable fuel volume requirement which is not required to be advanced biofuel).

Comment:

EPA admits that 15 billion gallons of ethanol consumption cannot be reached, so the conventional volume should not be raised to 15.25 billion in 2024 and 2025.

Response:

The implied volume requirement for conventional renewable fuel is not a requirement for the use of ethanol. Our assessment of the fuels market indicates that as in years past, 15 billion gallons can be achieved through a combination of ethanol used as E10, ethanol used as higher-level ethanol blends (E15 and E85), and the remainder being made up with non-ethanol biofuels such as biodiesel and renewable diesel.

We have also determined that the supplemental volume requirement of 250 million gallons in 2023 can be met with BBD in excess of that needed to meet the advanced biofuel standard. In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. Given that we anticipate that additional advanced biofuel will be used to make up for the expected shortfall in conventional biofuel volume needed to meet the implied 15.0 billion gallons, we do not anticipate that this change will have any impact on the volumes actually used to comply with the standards. See also responses to comment in RTC Section 6.2.2.

Comment:

The 15 billion gallon volume requirement for conventional renewable fuel should be the floor, not the ceiling.

Response:

Because we are adding a supplemental volume requirement of 250 million gallons to the implied conventional volume requirement of 15 billion gallons in 2023, the net effect is that the volume of renewable fuel that is not required to be advanced biofuel is 15.25 billion gallons in 2023. In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. Given that we anticipate that additional advanced biofuel will be used to make up for the expected shortfall in conventional biofuel volume needed to meet the implied 15.0 billion gallons, we do not anticipate that this change will have any impact on the volumes actually used to comply with the standards. See also responses to comment in RTC Section 6.2.2.

Comment:

EPA should be increasing the implied volume requirement for conventional renewable fuel every year, not just in 2024.

Response:

Our determination of the appropriate volume requirements to establish for 2023–2025 is based on all of the factors that EPA is required to analyze under section 211(o)(2)(B)(ii) of the Clean Air Act, 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 2023–2025 is considerably less than 15 billion gallons, and that feedstock limitations constrain the amount of biodiesel and renewable diesel that is in excess of that needed to meet the advanced biofuel standard and which can help to meet the shortfall in corn ethanol. Based on the many factors that we analyzed, we have determined that it would not be appropriate to increase the implied volume requirement for conventional renewable fuel above 15.0 billion gallons in 2024 and 2025. Doing so would not be expected to increase the volume of conventional biofuel 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:

The conventional standard needs to reflect the expanded opportunities for E15 growth that will exist through the end of 2025.

Response:

Our approach to projecting the total volume of ethanol that will be consumed takes into account projections of expanded offerings of E15 and E85 at retail service stations. Among other things, these projections are based on information about USDA's grant programs and estimates of the ongoing efforts of industry and private parties. For the final rule, we have updated these projections to account for the most recent information available, including the provisions of the Inflation Reduction Act. See RIA Chapter 6.5 for more information.

Comment:

A number of commenters claimed that the proposed implied volume requirement for conventional renewable fuel of 15 billion gallons in 2023 and 15.25 billion gallons in 2024 and 2025 cannot be met with ethanol, and that as a result they are too high. In this context, some commenters referred to conventional renewable fuel as the "ethanol requirement" or the "ethanol mandate," while others made the implicit assumption that the total volume of ethanol that would be used was identical to the implied volume of conventional renewable fuel.

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. See CAA section 211(o)(1)(J). The statutory scheme thus plainly allows other renewable fuels, besides ethanol, to qualify as renewable fuel so long as they meet the statutory requirements. See CAA section 211(o)(1)(J), (o)(2)(A)(i). 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. In establishing the volume requirements for years without statutory volumes, EPA is mandated to consider renewable fuels generally, not just ethanol. 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).

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). See CAA section 211(o)(1)(B)(i)(I), (o)(2)(B)(i)(II). In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. As explained in RIA Chapter 6.2, advanced biofuel volumes, together with corn ethanol, will enable the market to satisfy the total renewable fuel standard, including the 15.0 billion gallon implied conventional renewable fuel portion finalized in this rule. See also responses to comment in RTC Section 6.2.2.

Comment:

Several commenters stated that the implied volume requirement for conventional renewable fuel in 2023–2025 should be set at a level reflecting the realities of limitations in ethanol consumption. Some said that the implied conventional renewable fuel volume requirement should be set at the level of projected ethanol consumption. Others said that it should be set at or below the E10 blendwall.

Response:

We acknowledged in the proposal that ethanol consumption in 2023–2025 cannot reach 15.25 billion gallons due primarily to infrastructure constraints associated with E15 and E85. For the proposal we projected that consumption of ethanol in the form of E15 and E85 would increase through 2025, and we have updated the projection for this final rule with more recently available information. 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, as discussed in RIA Chapter 2.1.1. Nevertheless, total ethanol consumption is still projected to fall far short of 15.25 billion gallons. As explained above, 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 D6 RIN prices would likely be lower if we set the implied conventional renewable fuel volume requirement below the E10 blendwall. While we requested comment on doing this, after further consideration we do not believe it would be appropriate to do so for 2023–2025. We do not believe it would be appropriate to ignore the potential for increased volumes of ethanol that can be consumed as E15 and E85 when determining the applicable volume requirements, nor the volumes of non-ethanol advanced biofuel that can be produced and consumed in excess of the applicable advanced biofuel volume requirement. See also responses to comment in RTC Section 6.2.2.

Comment:

Several stakeholders said that higher volume requirements do not result in higher ethanol consumption, in particular higher sales volumes of E15 and E85.

Response:

From its inception, the RFS program was intended to increase the use of renewable fuels in the transportation sector over time. The standards themselves were expected to create the incentive for the market to respond with greater production of renewable fuels, and for infrastructure to be modified to allow increased volumes of renewable fuel to be consumed. Renewable fuel production and consumption has indeed increased since the program was established through the Energy Policy Act of 2005, and at least part of that increase can be attributed to the RFS program.

Ethanol consumption, however, appears to have had a more limited response to the considerable incentives created by the RFS program than other types of renewable fuel. Ethanol use as E10 has been economical to blend without the incentive created by the RFS program since the program's inception, with volumes in the early years far exceeding the volumes mandated by the RFS program. After effectively reaching the E10 blendwall in the 2011–2015 timeframe (see RIA Figures 1.7-2 and 1.7-3), ethanol use has increased much more slowly due to poorer economics and various constraints that directly affect sales of higher level ethanol blends such as E15 and E85. Further increases in biofuel production and use were driven largely by increasing volumes of biodiesel and renewable diesel as more viable alternatives. As evidenced by the relatively consistent increase over time in the average ethanol concentration of gasoline, consumption of E15 and E85 has continued to increase, albeit slowly. This increase has been supported by the RFS program as well as other programs, such as USDA's BIP and HBIIP.

By continuing to set the total renewable fuel standard in such a way that the implied conventional biofuel standard remains above the E10 blendwall, the final standards are expected to continue to provide a considerable financial incentive for E15 and E85 growth. Our assessment of the ability of the market to meet the 2023–2025 volume requirements includes a projection of moderate increases in the consumption of ethanol in the form of E15 and E85. See detailed analysis in RIA Chapter 6.5.

Comment:

One stakeholder said that EPA did not consider costs to consumers and negative environmental impacts when it decided to propose 15.25 billion gallons for the implied volume requirement for conventional renewable fuel.

Response:

One of the statutory factors that EPA is required to analyze when exercising the Set authority under CAA section 211(o)(2)(B)(ii) is "the impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods." The costs of the proposed volume requirements were analyzed at length for the proposal in DRIA Chapter 10.4. For this final rule, we discuss the implications of renewable fuel costs in various places throughout the preamble, including in assessing the costs of the candidate volumes in Preamble Section IV.C and in the context of our determination of the appropriate volume requirements to establish for 2023–2025 in Preamble Section VI. We provide a detailed discussion of our analysis of costs in RIA Chapter 10.4 and address other comments related to costs in RTC Section 9.1.1.

Regarding environmental impacts, we indicate in the preamble that our analyses has led us to conclude that some impacts are beneficial while others may be adverse. For instance, in Preamble Section VI we acknowledge the possibility, although unlikely, that increased production of soybean oil and canola oil could result in greater wetlands conversion, and adverse impacts on ecosystems, wildlife habitat, water quality, and water supply. Since our determination of the appropriate volume requirements for years after 2022 must be based on an analysis of all of the factors enumerated in the statute, we considered not only these adverse impacts but also the benefits. On balance, we believe that on consideration of all factors, the volume requirements that we are finalizing in this action are appropriate.

Comment:

One stakeholder opposed the implied volume requirement for conventional renewable fuel of 15.25 billion gallons because it would result in more land being converted to corn cropland. Another stakeholder said that the volume requirements should be reduced to be consistent with the amount of cropland that is compliant with the provisions of the Energy Independence and Security Act.

Response:

Under the RFS program, qualifying renewable fuels must be produced from "renewable biomass." CAA section 211(o)(1)(I)(i) defines renewable biomass to mean "Planted crops and crop residue harvested from agricultural land cleared or cultivated at any time prior to the enactment of this sentence that is either actively managed or fallow, and nonforested." To implement this statutory requirement, EPA created the aggregate compliance provision in

2010.[33] 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 corn may be needed to produce ethanol in the 2023–2025 timeframe in comparison to previous years, the aggregate compliance provision ensures that the additional corn cannot result in a net increase in the conversion of non-cropland to cropland.

Comment:

Several stakeholders commented on the interplay between the implied volume requirement for conventional renewable fuel and the volume requirement for advanced biofuel. Some said that an increase in the advanced biofuel volume requirement should only occur if the total renewable fuel volume requirement is increased by the same amount, which would effectively mean no change in the implied volume requirement for conventional renewable fuel. Others said that the portion of the implied volume requirement for conventional renewable fuel that is not met with corn ethanol should be shifted to the advanced biofuel volume requirement, which would result in no change in the volume requirement for total renewable fuel.

Response:

In the proposal we indicated that it was very unlikely that an implied volume requirement for conventional renewable fuel of 15.25 billion gallons could be met entirely with corn ethanol and reaffirm this position in RIA Chapter 6.2 with respect to the final volume of 15.0 billion gallons. Instead, ethanol consumption will be constrained by infrastructure, and the difference between projected volumes of ethanol and 15.0 billion gallons would be met with BBD in excess of the advanced biofuel volume requirement. The total volume of BBD actually consumed would thus be determined not merely by the level of the advanced biofuel volume requirement, but also by the implied volume requirement for conventional renewable fuel.

In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. Given that we anticipate that additional advanced biofuel will be used to make up for the expected shortfall in conventional biofuel volume needed to meet the implied 15.0 billion gallons, we do not anticipate that this change will have any impact on the volumes actually used to comply with the standards. See also responses to comment in RTC Section 6.2.2.

Were we to have reduced the implied conventional renewable fuel volume requirement further, approaching the E10 blendwall, opponents of this approach correctly point out that incentives for higher level ethanol blends such as E15 and E85 could be lost. We estimate that this would amount to about 300 million gallons of ethanol, representing about 2% of total projected corn ethanol consumption. However, the lost corn ethanol volume would be replaced by additional BBD.

A simultaneous increase in both the advanced biofuel volume requirement and the total renewable fuel volume requirement would have decidedly different impacts. In this approach,

[33] 75 FR 14701 (March 26, 2010).

there would be no change in corn ethanol consumption but a substantial increase in BBD consumption. This could only occur if there were sufficient feedstocks for the production of the additional BBD, and/or additional imports of BBD or feedstocks could occur. Our assessment of BBD feedstocks can be found in RIA Chapter 6.2.3, and responses to comments on this issue can be found in RTC Section 4.2.

Comment:

One stakeholder said that EPA should not be incentivizing ethanol since electric vehicles are expanding and will result in less gasoline consumption and therefore less ethanol consumption. Another stakeholder said that the volume requirements for liquid biofuels should be reduced to create more opportunities for renewable electricity in transportation.

Response:

While sales of electric vehicles (EV) are indeed increasing, the transportation sector will continue to be dominated by vehicles and engines that operate on liquid fuels in the 2023–2025 timeframe. We have based our estimates of ethanol consumption for this time period on forecasts of gasoline demand from EIA, and those forecasts take into account the penetration of EVs into the fleet.

We do not believe that reducing the RFS volume requirements for liquid biofuels would create an opportunity for renewable electricity to expand. A reduction in the use of liquid biofuel would have no impact on the number of vehicles and engines designed to operate on liquid fuels. Sales of EVs are driven primarily by their costs in comparison to internal combustion engine vehicles. Operating costs, convenience, and perceptions about the environmental impacts of EVs also play a role, but the volume of renewable liquid fuels consumed is unlikely to have an impact on these factors that is noticeable or meaningful to the average consumer.

Comment:

One stakeholder said that the proposed volume requirements would place an excessive burden on non-cellulosic advanced biofuel because of the shortfall in corn ethanol in comparison to the 15.25 billion gallons requirement for conventional renewable fuel.

Response:

We acknowledged in the proposal that non-cellulosic advanced biofuel in excess of that needed to meet the advanced biofuel volume requirement would likely be used to help meet the implied volume requirement for conventional renewable fuel. However, we determined that the total amount of available feedstocks and production capacity would be sufficient to meet these requirements. For this final rule we have updated our assessment of available feedstocks and have concluded that the applicable final volume requirements can be met with some combination of domestically produced feedstocks, imports of feedstocks, and imports of BBD. See further discussion in RIA Chapter 6.2.

Comment:

One stakeholder said that there is no justification for setting the implied volume requirement for conventional renewable fuel below 10% of gasoline demand.

Response:

There are three arguments supporting the reduction of the implied volume requirement for conventional renewable fuel to below the E10 blendwall. The first is that D6 RIN prices would decrease, which would in turn reduce the overall amount that obligated parties pay for RINs to comply with their RVOs. The second is that it would more closely align the applicable standards with the expected consumption volumes of conventional renewable fuel versus advanced biofuel. Third, this approach would greatly reduce the likelihood that imported palm-based renewable diesel is used for compliance with the RFS obligations, thus maximizing the probability that the GHG benefits associated with our proposed standards occur. While not explicitly discussed in the proposal, this approach would also result in a small amount of BBD displacing the ethanol in E15 and E85, increasing the GHG benefits of the RFS program. Nevertheless, we have decided not to implement this approach in this final rule (see Preamble Section VI for our explanation of the volume requirements we are finalizing in this rule).

Comment:

One stakeholder said that the applicable standards should be based on non-crop feedstocks only, with a focus on waste feedstocks. In this context, the implied volume requirement for conventional renewable fuel should be reduced to zero. Another stakeholder provided a similar comment with regard to the implied volume requirement for non-cellulosic advanced biofuel, saying that EPA should only include renewable fuels made from waste feedstocks.

Response:

The volume requirements under the RFS program fall into four broad categories defined by the statute, and do not include any mechanism to distinguish between crop and non-crop feedstocks. Thus the applicable standards, regardless of the level at which they are set, cannot prevent or even disincentivize the use of crop-based renewable fuel to comply with those standards. Moreover, since the statute allows crop-based feedstocks to be used to produce renewable fuel that qualifies under the RFS program, we do not believe that we have the authority to prohibit their use even if a mechanism were available within the structure of the standards.

If we were to base the volume requirements on only those renewable fuels that are produced from non-crop-based feedstocks, we expect that they would be considerably lower than those we are finalizing in this action for BBD, advanced biofuel, and total renewable fuel. However, the market would still determine the mix of biofuels that are used to comply with those volume requirements. Insofar as crop-based feedstocks were the least costly or otherwise most attractive renewable fuels, they would dominate the overall pool of renewable fuels used for compliance.

While some stakeholders discussed some of the adverse impacts associated with crop-based feedstocks, such feedstocks also provide some advantages. These include reductions in GHGs, increases in energy security, and benefits in rural economic development. CAA 211(o)(2)(B)(ii) provides EPA flexibility to weigh the statutory factors as it deems appropriate in determining the applicable volume requirements for years without statutory volumes. See Preamble Section VI for further discussion of our rationale for the final applicable standards in light of all the factors we are required to analyze.

Comment:

One stakeholder said that EPA's proposal of 15.25 billion gallons for the implied volume requirement for conventional renewable fuel is inconsistent with the statutory criteria.

Response:

In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. We believe our final volumes for 2023-2025 comport with all statutory requirements. See Preamble Section VI for further discussion of our evaluation of the statutory factors.

Comment:

Several commenters said that EPA should "rebalance" the advanced biofuel and conventional renewable fuel volume requirements by setting them at levels that match demonstrated production and consumption of biofuels that correspond to each biofuel category.

Response:

We did not explicitly request comment on an approach in which the implied volume requirement for conventional renewable fuel would be reduced to the projected level of corn ethanol consumption, and the advanced biofuel volume requirement would be increased by an equivalent amount. Nevertheless, this approach would be similar to the one on which we did request comment, under which the implied volume requirement for conventional renewable fuel would be reduced to below the E10 blendwall. Our responses to comments on this latter approach are provided in RTC Section 6.2.2, and are largely applicable to the slightly different approach suggested by commenters.

As we noted in the proposal, it is unlikely that there would be any meaningful reduction in D6 RIN prices unless the implied volume requirement for conventional renewable fuel were reduced to below the E10 blendwall. At least one advantage would remain, however, if it were reduced to our projected level of corn ethanol consumption: the guarantee that no amount of renewable fuel in excess of corn ethanol could be imported palm-based renewable diesel, thus maximizing the probability that the GHG benefits associated with our proposed standards occur. However, we have decided not to implement this approach to setting the applicable volume requirements for

2023–2025 (see Preamble Section VI for our explanation of the volume requirements we are finalizing in this rule).

Comment:

One stakeholder said that the proposed volume requirement for conventional renewable fuel will result in a shortfall of D6 RINs.

Response:

While D6 RINs represent conventional renewable fuel, the implied volume requirement for conventional renewable fuel need not be met only with D6 RINs. Under the regulations at 40 CFR 80.1427(a)(2)(iv), RINs with any D code can be used to meet that portion of the total renewable fuel volume requirement which is not required to be advanced biofuel. Thus, although the total number of D6 RINs may fall short of the implied volume requirement for conventional renewable fuel due to constraints on the consumption of ethanol, that shortfall would not by itself represent an inability of the market to supply sufficient RINs to comply with the applicable standards. Indeed we have concluded that there will be sufficient RINs available in 2023–2025 to enable obligated parties to comply with the standards we are setting in this action.

Comment:

One stakeholder said that EPA should respond to an unanticipated increase in ethanol demand by increasing the total advanced RVO commensurate with the additional incremental ethanol gallons to avoid a situation wherein more ethanol consumption results in a reduction in advanced biofuel consumption.

Response:

We have projected increases in the consumption of higher ethanol blends such as E15 and E85 in the 2023–2025 timeframe. The result is expected to be an increase in the nationwide average ethanol concentration. However, total ethanol consumption is driven primarily by gasoline demand which, according to EIA's AEO2023, is projected to be lower in 2025 than it was in 2022. Thus we expect that total U.S. ethanol consumption will actually be lower in 2025 than it was in 2022.

Once we establish the percentage standards by specifying them in the regulations at 40 CFR 80.1405(a), they remain applicable unless EPA changes them. Such changes are uncommon and would only be undertaken under exceptional circumstances. Moreover, a change to the regulations would require a full notice-and-comment rulemaking process. The applicable percentage standards do not specify the mix of renewable fuel types that must be used to meet them, and the market may choose a different mix than we have projected will occur. We do not believe that a circumstance such as that described by the commenter would, in and of itself, warrant a change to the applicable percentage standards.

Comment:

One stakeholder said that infrastructure and costs were not properly considered in determining the implied conventional renewable fuel volume requirements for 2023–2025.

Response:

Our detailed assessment of infrastructure related to ethanol is provided in RIA Chapter 7.5. There we discuss the constraints on ethanol supply and consumption that are associated with the vehicles that can consume higher level ethanol blends and the retail service stations that offer those blends. We made projections of future ethanol consumption based on that assessment of infrastructure as discussed in detail in RIA Chapter 6.5.

Our detailed assessment of costs is provided in RIA Chapter 10. Costs were incorporated into our assessment of the volumes of ethanol likely to be consumed if the RFS program were to cease (the "No RFS" baseline), and were considered along with all of the other statutory factors required under 211(o)(2)(B)(ii) in determining the applicable volume requirements for 2023–2025.

Comment:

One stakeholder said that the final implied volume requirements for conventional renewable fuel were not based on an assessment of expected future production of renewable fuel.

Response:

The implied volume requirement for conventional renewable fuel is not a requirement for conventional renewable fuel per se. That is, it is not a requirement for RINs with a D code of 6. Instead, it is a requirement for the use of qualifying renewable fuel in excess of the advanced biofuel volume requirement. Thus RINs of any D code can be used to meet the implied volume requirement for conventional renewable fuel. Our determination of the appropriate volume requirements for conventional renewable fuel takes into account the availability of all forms of renewable fuel, not just ethanol.

We are required under CAA section 211(o)(2)(B)(ii)(III) to analyze "the expected annual rate of future commercial production of renewable fuels." However, as discussed in the prologue to RIA Chapter 6, we also considered consumption in our assessment as an inherent element of other statutory factors such as infrastructure.

Comment:

One stakeholder said that the proposed implied volume requirement for conventional renewable fuel of 15.25 billion gallons was arbitrarily chosen.

Response:

The implied conventional renewable fuel volumes, while derived from the volume requirements we are establishing in this rule, are not themselves volume requirements. As discussed in Preamble Sections III and VI, the total renewable fuel volumes we are establishing for 2023–2025 are based on the volumes of renewable fuel we project will be supplied each year. As a second step, we then consider how much of this total volume of renewable fuel should be required to be advanced biofuel.

Further, as described in Preamble Sections III and VI, the implied statutory volume targets for conventional renewable fuel in prior years represented a useful point of reference in the consideration of candidate volumes that may be appropriate for 2023–2025. Under the statute, conventional renewable fuel increased every year between 2009 and 2015, after which it remained at 15 billion gallons through 2022. In the 2020–2022 standards final rule, we implemented a supplemental standard of 250 million gallons of renewable fuel for 2022.[34] The net result was that the implied conventional renewable fuel volume requirement was effectively 15.25 billion gallons in 2022. This is again the case for 2023 where we are implementing a supplemental standard of 250 million gallons to complete our response to the court's remand of the 2016 standards (first initiated with a 250 million gallon supplemental standard in 2022). While in the proposal we took the resulting 15.25 billion gallons as the starting point for 2024 and 2025, in this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. Given that we anticipate that additional advanced biofuel will be used to make up for the expected shortfall in conventional biofuel volume needed to meet the implied 15.0 billion gallons, we do not anticipate that this change will have any impact on the volumes actually used to comply with the standards. See also responses to comment in RTC Section 6.2.2. As described in Preamble Sections III and VI as well, we then evaluated the candidate volumes to determine if they were appropriate to require after considering all of the environmental and economic factors that we are required to analyze under the statute. Had we determined that 15.0 billion gallons was not achievable in 2023–2025, or was otherwise inappropriate to require, we would have modified it to be consistent with the analyses we conducted.

Comment:

One stakeholder said that the benefits of the proposed standards do not outweigh the costs, and that as a result they should not be finalized.

Response:

While CAA 211(o)(2)(B)(ii) requires EPA to analyze both costs and other impacts of renewable fuels in the process of determining the appropriate volume requirements for years without statutory volumes, it does not require a direct comparison of costs to monetized benefits nor does it require that the applicable standards result in benefits exceeding costs. Nevertheless, we have

[34] 87 FR 39600 (July 1, 2022).

compared the estimated costs to those other impacts that we could monetize as described in Preamble Section IV.D in fulfillment of OMB Circular A-4. The projected costs of the proposed standards were higher than the monetized benefits as the stakeholder pointed out. However, we were not able to monetize all of the impacts. Our final determination of the final applicable volume requirements for 2023–2025 was based on a consideration of all of the statutory factors that we were required to analyze, as described in Preamble Section VI.

Comment:

One stakeholder said that the implied volume requirement for conventional renewable fuel should be reduced to below the E10 blendwall in order to limit the potential for imports of conventional biodiesel.

Response:

If the implied volume requirement for conventional renewable fuel were reduced to below the E10 blendwall, it is likely that it would be met entirely with domestically produced corn ethanol and that 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 would not be appropriate to set the implied volume requirement for conventional renewable fuel in this way at this time. Even so, we do not expect any meaningful volumes of conventional biodiesel to be imported in the 2023–2025 timeframe even with an effective conventional renewable fuel implied volume requirement of 15.0 billion gallons. There should be sufficient volumes of advanced biodiesel and renewable diesel in excess of the advanced biofuel standard to make up for any shortfall in corn ethanol.

Comment:

One stakeholder said that feedstock supply and associated land use is the principal question that EPA must evaluate, and it should form the basis for the candidate volumes.

Response:

In CAA section 211(o)(2)(B)(ii), Congress gave EPA flexibility to consider and weigh the statutory factors. There is no indication that Congress intended for feedstock supply or the associated land use to be the primary factor that EPA should consider in determining the appropriate standards for years without statutory volumes. In response to the commenter, we point out that we have investigated feedstock supply, primarily in the context of projecting volumes of biodiesel and renewable diesel. See discussion in RIA Chapter 6.2.3. Feedstock supply was of considerably less importance for corn ethanol because the U.S. already produces more than it consumes and is expected to continue exporting excess volumes of ethanol in the 2023–2025 timeframe. Thus it is not feedstock supply that limits ethanol consumption, but rather infrastructure, most notably the small number of retail service stations that offer E15 and/or E85. Moreover, we expect that total ethanol consumption between 2023–2025 will be lower than it was in 2022, despite the fact that consumption of E15 and E85 is projected to increase. This is the net result of lower future gasoline demand.

Comment:

One stakeholder said that EPA should set the implied volume requirement for conventional renewable fuel at 9.7% ethanol so that retail service stations will not be forced to sell E15.

Response:

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, and does not 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, and we expect that they will do so only if it provides them with some economic advantage.

Comment:

One stakeholder said that the proposed implied volume requirement for conventional renewable fuel of 15.25 billion gallons is aspirational.

Response:

In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. We do not believe that the implied volume requirement of 15.0 billion gallons for conventional renewable fuel is aspirational or otherwise beyond what the market is capable of achieving. We believe it is achievable with a combination of corn ethanol and biodiesel and renewable diesel in excess of the advanced biofuel volume requirement. See additional discussion in Preamble Section VI.D.

Comment:

One stakeholder said that the proposal for 15.25 billion gallons of conventional renewable fuel exceeds the statutory mandate of 15.0 billion gallons.

Response:

The statute specifies volume targets through 2022 (and for BBD, through 2012). For these years, the statutory volume targets are the basis for the applicable percentage standards unless EPA waives them in whole or in part using one of the available waiver authorities in CAA 211(o)(7). Under CAA 211(o)(2)(B)(ii), for years without statutory volumes, EPA must determine the applicable volume targets “based on a review of the implementation of the program during calendar years specified in the tables, and an analysis of” a specified set of economic and environmental factors. EPA must also abide by the requirements of CAA section 211(o)(2)(B)(iii)-(v). Although the statutory volume targets through 2022 may provide a helpful benchmark in the process of determining appropriate volume requirements for years after 2022, they do not represent requirements to which EPA must adhere. Nevertheless, in this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard.

Comment:

One stakeholder said that just because 15.25 billion gallons was projected to be met in 2022 does not mean that it can also be met in years after 2022.

Response:

In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. Our assessment of the appropriateness of the 15.0 billion gallon implied conventional renewable fuel volume is discussed in Preamble Sections III.C.3 and VI.D.

Comment:

One stakeholder said that the ratio of advanced biofuel to total renewable fuel for 2023–2025 should be set to be exactly the same as it was in 2022.

Response:

Under CAA 211(o)(2)(B)(iii), EPA must establish volume requirements for years after 2022 in such a way that "the applicable volume of advanced biofuel shall be at least the same percentage of the applicable volume of renewable fuel as in calendar year 2022." Since the statute explicitly says "at least," EPA is required only to ensure that the ratio of advanced biofuel to total renewable fuel is equal to <u>or greater than</u> that which existed in 2022. The ratio for 2022 was 0.273 (= 5.63 / 20.63). The ratios for 2023–2025 exceed this level in keeping with the statutory criteria.

Comment:

One stakeholder said that EPA's proposed volume requirements for conventional renewable fuel for 2023–2025 are lower than the ability of the market to provide ethanol, and that this is indicative of EPA's efforts to implement a RIN price cap or cost cap.

Response:

In the proposal, we did not discuss any type of price or cost control as the basis for any of the proposed volume requirements because such controls were not part of the process of determining those volume requirements. Instead, we based our proposed volume requirements on an assessment of all of the factors specific in the statute at CAA 211(o)(2)(B)(ii). With regard to the implied volume requirement for conventional renewable fuel, our candidate volume of 15.0 billion gallons was based on a projection of the volume of corn ethanol that we believe could be consumed under the influence of the applicable standards along with the volume of biodiesel and renewable diesel that could be supplied in excess of that needed to meet the volume requirement for advanced biofuel.

We did discuss the impact on RIN prices of an alternative approach under which the implied conventional renewable fuel volume requirement would be reduced to below the E10 blendwall. However, we did not propose such an approach and are not finalizing it in this action.

Comment:

One stakeholder said that EPA should reduce the implied volume requirement for conventional renewable fuel to below the E10 blendwall so that refiners can invest in low carbon fuels such as sustainable aviation fuel (SAF) instead of paying for D6 RINs.

Response:

In the proposal we acknowledged that a reduction in the implied volume requirement for conventional renewable fuel to below the E10 blendwall would likely result in a reduction in the price of conventional (D6) RINs. While the costs paid by obligated parties for RINs would decrease as a result, we continue to believe that the net impact on the cost of compliance with the RFS standards would be unaffected. This is due to our assessment of RIN cost passthrough, under which we have concluded that obligated parties recover the cost of RINs through their sales of gasoline and diesel.[35] Thus we do not believe that refiners would be afforded greater opportunities for investment in SAF if the implied volume requirement for conventional renewable fuel were reduced to below the E10 blendwall.

[35] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects," Dallas Burkholder, May 14, 2015.

6.2 Alternative Scenarios

6.2.1 15 Billion Gallon Implied Conventional Volume Standard in 2024 and 2025

Comment:

Few stakeholders specifically discussed the alternative on which we requested comment in which the implied conventional renewable fuel volume requirement would be set at 15.0 billion gallons rather than 15.25 billion gallons for 2024 and 2025. Those that did comment were split between supporting and opposing this alternative.

Response:

After further consideration, we have determined that it would be appropriate to set the total and advanced volumes such that the implied conventional renewable fuel volume requirement is 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. See further explanation in Preamble Sections III.C.3 and VI.D and RTC Chapter 6.1.4.

6.2.2 Reduce Implied Conventional Volume Standard Below the E10 Blendwall

Comment:

The RFS program is supposed to increase volumes over time, so EPA should not reduce the conventional volume.

Response:

Advanced biofuels have been and are projected to continue to make up for a shortfall in conventional biofuel volumes. The reduction in the conventional volume requirement on which we requested comment would be accompanied by an increase in the advanced biofuel volume requirement. As a result, there would be no impact on the total volume of renewable fuel, and in fact the total volume requirement would still increase every year. After further consideration, we have determined that it would be appropriate to set the total and advanced volumes such that the implied conventional renewable fuel volume requirement is 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. However,, we have decided it would not be appropriate to implement a further reduction in the conventional renewable fuel volume at this time.

Comment:

Were EPA to lower the conventional biofuel portion of the standard, the incentive provided by the RFS program for higher level ethanol blends would be eliminated, undercutting growth in ethanol volumes. To support the growth of renewable fuel volumes out into the future, it is important to continue to provide support for the growth of higher-level ethanol blends now.

Response:

In this final rule we are reducing the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in keeping with the statutory limits for prior years and shifting the 0.25 billion gallon difference to the advanced biofuel standard. However, as discussed in Preamble Section VI.D, we have finalized an implied conventional biofuel volume that remains well in excess of the E10 blendwall. We have done so in part to maintain an incentive to continue to provide support for the growth of higher-level ethanol blends in keeping with this comment.

Comment:

Reducing the conventional volume to the blendwall would strand investments in E15 and E85 infrastructure.

Response:

As discussed in RIA Chapter 2.1, we have projected that if the RFS program were to cease in 2023, ethanol consumption would likely drop to the E10 blendwall and consumption of E15 and E85 would drop to essentially zero. We believe that the same outcome would result if the implied volume requirement for conventional renewable fuel were to be reduced to the E10 blendwall or below. However, we have decided not to implement a reduction in the conventional renewable fuel volume to or below the E10 blendwall at this time. Our reduction in the implied conventional renewable fuel volume requirement from the proposed 15.25 billion gallons to 15.0 billion gallons for 2024 and 2025 in this final rule is not anticipated to have any impact on E15/E85 given that the implied conventional biofuel volume remains well in excess of the E10 blendwall.

Comment:

Shifting the conventional volume that is above the E10 blendwall to advanced biofuel would improve the GHG performance of the RFS program.

Response:

In the proposal we projected that the majority of the conventional 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. Thus, we believe there would be little change in overall GHG performance if we were to reduce the conventional volume without changing the total renewable fuel volume. 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). Such a shift could result in GHG benefits as the minimum GHG reduction threshold for advanced biofuel is greater than for conventional renewable fuel, but the actual impact on GHG emissions would depend on the GHG emissions associated with the advanced biofuel that replaced corn ethanol in this scenario.

Comment:

EPA should not just shift advanced biofuel from the conventional category to the advanced biofuel category, but should instead increase the advanced biofuel volume requirement without reducing conventional.

Response:

As discussed in Preamble Section III.B.2, there are important constraints on the availability of feedstocks for the production of biodiesel and renewable diesel. The total volume of biodiesel and renewable diesel that we project would be used to meet the applicable standards—both that used to meet the advanced standard and that used to make up for the shortfall in corn ethanol—takes these constraints into account. While we have updated our projections of the availability of feedstocks for biodiesel and renewable diesel for the final rule, those constraints continue to be important considerations in our assessment under the statutory factors of the appropriate standards to set for 2023–2025.

The alternative on which we requested comment, in which we would increase the volume requirement for advanced biofuel above the proposed level without increasing the volume requirement for total renewable fuel, would result in only a small increase in the volume of advanced biofuel actually consumed. Specifically, the volume of ethanol in excess of the E10 blendwall that we project would be consumed as E15/E85 under the proposed standards would instead be consumed as an energy-equivalent volume of renewable diesel. Thus, even under this alternative, there would in fact be some small increase in the consumption of advanced biofuel despite the fact that the total volume requirement would be unaffected. Nevertheless, we have decided that it is not appropriate at this time to implement this alternative approach.

Comment:

Several stakeholders supported the reduction of the implied conventional renewable fuel volume requirement because they expected that doing so would reduce the price of D6 RINs.

Response:

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.[36] 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. 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. For more information on the projected impact of RIN prices on retail fuel prices see RTC Section 9.1.4. For a discussion of the impact of alternative scenarios, including scenarios where the implied conventional renewable fuel volume was reduced to a volume below the E10 blendwall see RIA Chapter 10.6.

Comment:

EPA's alternative in which the implied conventional renewable fuel volume requirement would be reduced to below the blendwall with no change in the total renewable fuel volume requirement would result in no change in the actual mix of biofuel consumed, since some BBD that would be used to meet the conventional requirement would simply be shifted to the advanced requirement. Given that D6 RIN prices would drop with no change in actual biofuel use, there is no reason not to implement this alternative.

[36] 87 FR 80629 (December 30, 2022).

Response:

There would in fact be a small change in the mix of biofuels consumed under the alternative on which we requested comment—the ethanol consumed as E15 and E85 would likely be replaced by additional BBD. Given the broader support for increases is the use of higher ethanol blends through, for instance, USDA grants programs for expanded infrastructure, we do not believe that it would be appropriate at this time to eliminate RFS incentives for E15 and E85 by establishing an implied conventional renewable fuel volume requirement below the E10 blendwall.

Comment:

Several stakeholders said that EPA should reduce the implied conventional renewable fuel volume requirement to below the E10 blendwall without reducing the total volume requirement because doing so would place the focus of the RFS program on advanced biofuel where it belongs. Not only are all increases in the statutory volume targets after 2015 due to increases in advanced biofuel, but advanced biofuel is also required to have better GHG performance than conventional renewable fuel. One stakeholder also stated that this approach would send additional signals to the market to invest in advanced biofuels.

Response:

Although the alternative on which we requested comment would result in a substantially higher volume requirement for advanced biofuel, to a large degree this increase in the volume requirement would not correspond to an increase in actual consumption of advanced biofuel. Thus it would not, in reality, place the focus of the program on advanced biofuel to the degree that commenters may have perceived it to for the 2023–2025 timeframe that is the focus of this action.

It is not clear if reducing the implied conventional renewable fuel volume requirement without changing the total renewable fuel volume requirement would create additional market incentives for the expansion of advanced biofuels after 2025. We will consider such potential incentives when developing the volume requirements for 2026 and later.

Comment:

One stakeholder said that the implied conventional renewable fuel volume requirement should be reduced because the GHG benefits of corn ethanol are uncertain.

Response:

All renewable fuel that is produced from renewable biomass, meets a minimum GHG reduction threshold of 20%, and has an approved RIN generating pathway in Table 1 of 40 CFR 80.1426 is valid for generating RINs.[37] To the degree that such fuels can be produced and consumed, we believe it is appropriate to consider them when determining the applicable volume requirements.

[37] A renewable fuel may be exempt from the 20% GHG reduction criterion under CAA section 211(o)(2)(A)(i) and 40 CFR 80.1403.

As all analyses have some degree of uncertainty, uncertainty necessarily plays a role in the determination of those volume requirements. Thus we consider the uncertainty in estimated GHG benefits just as we consider the uncertainty in all factors that we are required to analyze under CAA 211(o)(2)(B)(ii). We do not believe that the uncertainty in the estimated GHG benefits of corn ethanol precludes it from being included in the determination of the appropriate implied conventional renewable fuel volume requirement. See also responses to comments on GHG assessment in RTC Section 9.2.1.

Comment:

One stakeholder disagreed with our statement in the proposal that if the implied conventional renewable fuel volume requirement is set below the E10 blendwall, D6 RIN prices will be very low, whereas if it is set above the E10 blendwall, D6 RIN prices are considerably higher. Instead, the stakeholder believes that D6 RIN prices rise when the implied conventional renewable fuel volume requirement is higher than actual ethanol consumption rather than the E10 blendwall.

Response:

RIN prices generally reflect the incentive needed for consumers to buy renewable fuel up to the levels required by the standards. If consumers need no such incentive, i.e. if consumers will buy renewable fuel at levels exceeding the standards, then RIN prices will be very low. Our assessment of consumer demand for E15 and E85 indicates that consumers will generally not purchase these fuels without the additional economic incentive provided by D6 RINs. In contrast, consumers will continue to purchase E10 even if there is no additional incentive provided by D6 RINs. As a result, it is the ethanol volume associated with the E10 blendwall, rather than the ethanol volume associated with consumption of E10, E15, and E85, which marks the dividing line between very low D6 RIN prices and higher D6 RIN prices. See RIA Chapter 2.1.1 for further discussion of consumer demand for E15 and E85 under the influence of the RFS program. For other responses to comments on RIN prices, see RTC Section 9.1.3.

6.2.3 Years Addressed by Rulemaking

Comment:

While many stakeholders supported the proposal to establish volume requirements and associated percentage standards for three years, some stakeholders requested that standards be set for fewer than 3 years. No stakeholder requested that standards be set for more than three years.

Response:

Although we requested comment on the possibility of setting standards for 2026 in addition to 2023–2025, we also recognized in the proposal the additional uncertainty that is inherent in setting standards for longer timeframes. Stakeholders generally supported this view. We have decided that it would not be appropriate to set standards for 2026 in this action.

Comment:

EPA should not set standards for only one or two years. Standards for multiple years help ensure certainty for the market and the necessary stability for longer term investments.

Response:

While we requested comment on setting standards for only one or two years instead of three years, we have decided that it would not be appropriate to do so for this action. As described in Preamble Section III.A, the market benefits from knowing the applicable standards for multiple years into the future. Knowing the minimum demand that will exist in the future helps to provide a secure foundation for investments in new technologies and new production capacity, which furthers the RFS program's goal of increasing the use of renewable fuels in the transportation sector over time.

Comment:

One stakeholder said that EPA did not provide sufficient analysis of the possible standards for 2026.

Response:

We did not derive candidate volumes for 2026 in the same way that we did for 2023–2025, by analyzing those statutory factors most closely related to supply. Instead, we extrapolated the trends in the proposed volumes for 2023–2025. We believe that this was legitimate and provided a reasonable basis for stakeholders to see what 2026 volume requirements might look like. However, we did not explicitly analyze the economic or environmental impacts of the 2026 volumes. As we did not propose to set standards for 2026, and have determined that it would not be appropriate to do so in this action, we do not believe that the less robust analysis of those volumes in the proposal is pertinent.

Comment:

One stakeholder said that the possible cellulosic volume requirement for 2026 was too low, and was not supported by sufficient analysis.

Response:

The possible cellulosic volume requirement for 2026 that we presented in the proposal was not based on the same methodology that we used to project cellulosic volumes for 2023–2025. Instead, the 2026 volume was based on an extrapolation of the trends in the proposed volumes for 2023–2025. We used this approach to illustrate what 2026 cellulosic volumes could be, but we acknowledge that the use of the same methodology for 2026 as we used for 2023–2025 might have led to different cellulosic volumes. Regardless, as we did not propose to set standards for 2026, and have determined that it would not be appropriate to do so in this action, we do not believe that the less robust analysis of the cellulosic volumes in the proposal is pertinent.

Comment:

Several stakeholders said that we should set standards only for 2023 and 2024 in this action because the market circumstances for 2025 are too uncertain. Sources cited for this uncertainty included expanding production capacity for renewable diesel, the fact that the eRIN program is new and therefore its impact on the market will be difficult to predict, and general uncertainty about feedstock and fuel supply in 2025.

Response:

In the proposal we acknowledged the fact that there is additional uncertainty inherent in setting standards for longer timeframes. Essentially all stakeholders recognized this fact. Additionally, there is no way to determine if the uncertainty is significantly greater when setting standards for 2025 as compared to setting standards for 2024, or only moderately greater. Our intention in proposing to set standards for three years was to balance the inherent uncertainty in the determination of those standards with the greater certainty afforded to the market by knowing what the applicable standards will be several years in advance. There is therefore considerable judgment involved in determining the appropriate number of years for which to set standards. Many stakeholders agreed with our assessment that setting standards for 3 years was appropriate, and no stakeholder provided new information regarding the uncertainty of setting standards for multiple years in one action that we did not consider in the proposal. We therefore continue to believe that setting standards for 2023–2025 in this action is appropriate.

Note that we have decided not to finalize the eRIN program in this action. Therefore, concerns about uncertainty related to the eRIN program and projecting quantities of renewable electricity for 2023–2025 are not relevant for this action.

Comment:

One stakeholder said that we should set standards only for 2023 in this action because EPA has not updated its GHG assessments, and because EPA has not completed consultation with the National Marine Fisheries Service and the Fish and Wildlife Service as required under the Endangered Species Act. Another stakeholder said that we should set standards only for 2023 because there is too much uncertainty about biofuel production and demand for 2024 and beyond.

Response:

Under CAA 211(o)(2)(B)(ii)(I), EPA must analyze the impact of the production and use of renewable fuels on climate change. Congress provided EPA flexibility to consider these factors without rigidly detailing the manner or method of such an analysis. As discussed in Preamble Section IV.A and in RIA Chapter 4.2, we have analyzed the climate change impacts of the candidate volumes through a review of biofuel-specific lifecycle GHG assessments available in the literature. We believe that the climate change assessment in this final rule meets the statutory requirements. Although not used to inform this rulemaking, we have also advanced the science of analyzing GHG impacts of biofuels through a model comparison exercise that will assist EPA in its assessment of GHG impacts of the transportation sector in the future. We believe that our model comparison exercise prepares EPA for more robust future assessments of GHG impacts. For responses to comments on our GHG analysis, see RTC Section 9.2.1.

As discussed in Preamble Section I.D, EPA is in consultation for this Set rule with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service (together, "the Services") as required under the Endangered Species Act (ESA). EPA's obligations to set standards under CAA 211(o) are separate and independent from its obligation to consult under the ESA. Therefore, even if EPA were to fail to consult with the Services under ESA section 7(a) for an agency action related to the RFS program, EPA's obligations to set standards would remain pursuant to CAA section 211(o).

As discussed in the response to the previous comment, we recognize the uncertainty inherent in making projections for future years, and that this uncertainty increases for longer timeframes. However, we are required under the statute to set standards for future years regardless of the uncertainty. Indeed, we have established standards for future years since 2008 under the RFS program (and have been exercising the set authority in CAA section 211(o)(2)(B)(ii) for BBD for years since 2013), and we do not believe that the uncertainty about biofuel production and demand for 2024 is any more or less pronounced now than it was in those previous standard-setting rulemakings to warrant delaying setting 2024 standards until after this final rule is released.

Finally, we do not believe it would be appropriate to only set standards for 2023 in this action since doing so would mean that it would be very unlikely for the 2024 standards to be set before January 1, 2024, and that there could be a cascading impact on the timing of setting standards for subsequent years. Perpetually late or late and retroactive standards would undermine the certainty that EPA intends to provide to the market to ensure that renewable fuel production and use can continue to increase over time.

Comment:

One stakeholder said that EPA should only set standards for 2023 if it is unwilling to increase the 2024 and 2025 BBD and advanced biofuel volume requirements above the proposed levels.

Response:

This stakeholder said that the proposed volume requirements for BBD and advanced biofuel were too low. For responses to this and similar comments, see RTC Sections 6.1.2 and 6.1.3.

We interpret this comment as a request to leave the 2024 and 2025 BBD and advanced volume requirements unsettled for as long as possible to maximize the chance that with more time and data, EPA would establish them at levels higher than those we proposed. We believe that this would be inappropriate inasmuch as it would very likely mean not setting the 2024 standards until after January 1, 2024. It also increases the likelihood that EPA misses the statutory deadlines to set volumes for 2024 and 2025. While EPA has on occasion set standards for a given year after the year in question has begun or has passed, we acknowledge that doing so creates additional uncertainty in the market and should be avoided whenever possible. Leaving the 2024 standards unsettled would reduce the ability of the market to plan for and ultimately comply with the 2024 standards. Meanwhile, there is no guarantee that new information would come to light in the next few months that would support EPA finalizing higher BBD and advanced volumes for 2024 and 2025 as the stakeholder would prefer. EPA has had sufficient time to consider the available information related to volumes of BBD and advanced biofuel and have concluded that are both achievable in 2024 and 2025 and appropriate to require.

Comment:

Several stakeholders said that EPA should establish the volume requirements for three years, but should only establish the applicable percentage standards for 2023 and 2024. This would allow the most recent projections of 2025 gasoline and diesel consumption to be used to calculate the percentage standards, thereby making them more accurate.

Response:

More recent projections of gasoline and diesel consumption are indeed likely to be closer to actual consumption than older projections. However, this is not the only valid consideration when establishing applicable percentage standards for the future. We must also consider the certainty to the market that the applicable percentage standards provide. Since the volume requirements are not stipulated in the regulations and create no obligations for any party, they do not create certainty of demand for the market; the market cannot place the same confidence in the volume requirements that it can in the percentage standards. Establishing volume requirements for 2025 without the associated percentage standards would fall short of our goal of creating market certainty and providing sufficient leadtime for the market to supply the required volumes.

In addition, establishing the 2025 volume requirements in this action but leaving the 2025 percentage standards to a subsequent action would provide no guarantee that the 2025 volume requirements themselves would not be reconsidered in that subsequent action. EPA has taken the position that it should use the most recent and up-to-date information available when it sets standards. In addition to the most recent projections of gasoline and diesel, EPA would also be compelled to consider any other information available at the time that the percentage standards are set, and in doing so, may need to adjust the 2025 applicable volumes requiring additional analysis and notice and comment. As a result, it may not be possible for EPA to establish 2025 volume requirements in this action that remain unchanged in the subsequent action that sets the percentage standards, adding uncertainty to the market's expectation of the renewable fuel volumes that will be required.

Comment:

Several stakeholders said that the prospective applicable percentage standards should only be set annually as they have been in the past.

Response:

As discussed in Preamble Section II.D, for years after 2022 EPA has the authority to establish the applicable percentage standards for multiple future years at one time. This flexibility contrasts to the years prior to and including 2022 when EPA was required to set the percentage standards annually.

As discussed in Preamble Section III.A, we believe that setting the percentage standards for multiple years at one time in this action provides the market with additional certainty and promotes the market's ability to comply with those future standards. This in turn is consistent with the broad goal of the RFS program to increase the use of renewable fuels in the transportation sector over time.

We recognize that setting the percentage standards for multiple future years at one time requires that we use projections of gasoline and diesel demand that are likely to be less certain than later projections. In targeting three years, we have attempted to balance the additional uncertainty that this fact creates with the greater certainty for the market of future demand for renewable fuel created by known standards. Additionally, EPA retains the authority to waive any portion of the standards after they have been set using one or more of the waiver authorities in CAA section 211(o)(7) if the need arises.

Comment:

One stakeholder supported establishing percentage standards for three years in this action, but said that EPA should nevertheless promulgate annual rulemakings to revisit those standards to ensure that they are appropriate.

Response:

Once the applicable percentage standards are established by adding them to the regulations at 40 CFR 80.1405(a), they remain effective until and unless EPA changes them through a notice-and-comment rulemaking process. If circumstances warrant, EPA is able to adjust the applicable regulations through such a rulemaking process. We do not believe that it would be appropriate to annually evaluate the 2023–2025 standards as was required by the statute prior to 2023. Doing so would undermine the market certainty that was intended by establishing standards for several years into the future, and in addition would be an inappropriate and immoderate use of government resources.

Comment:

One stakeholder supported the proposal to establish percentage standards for three years, but asked that EPA increase those standards if supply increases.

Response:

Once the applicable percentage standards are established by adding them to the regulations at 40 CFR 80.1405(a), they remain effective until and unless EPA changes them through a notice-and-comment rulemaking process. Through the waiver authorities available in CAA 211(o)(7), EPA can reduce the volume requirements and associated percentage standards after they have been established. The criteria for waiving volumes are specific to each waiver. To increase the volume requirements and associated percentage standards would require that EPA reconsider the rationale in the previous rulemaking which established those standards using the criteria specified in CAA 211(o)(2)(B)(ii). That is, EPA would be obligated to revisit all of the environmental and economic factors required under the statute, as described in Preamble Section I.

7. Percentage Standards

7.1 General Comments on Percentage Standards

Comment:

Several commenters expressed concern about setting percentage standards for 2025 as part of this action and stated that EPA had not assessed the accuracy of using AEO, rather than STEO, for gasoline and diesel projections.

Response:

As discussed in RIA Chapter 1.11, we have assessed the accuracy of the AEO gasoline and diesel projections compared to the volumes reported by obligated parties. As a result of this assessment, we have implemented an additional adjustment factor to the AEO gasoline and diesel projections used to calculate the percentage standards to better align the projections with the volumes reported by obligated parties.

Comment:

One commenter stated that EPA's projection of diesel fuel used to calculate the proposed percentage standards was 3 billion gallons lower than the value in AEO 2022.

Response:

As discussed in Preamble Section VII.A, the gasoline and diesel volume projections used to calculate the percentage standards include several adjustments to EIA's gasoline and diesel volume projections, including subtracting out the volume of gasoline, diesel, and renewable fuel used in Alaska and the volume of diesel used in ocean-going vessels. These adjustments account for the discrepancy in diesel fuel volume projections cited by the commenter.

7.2 Accounting for Small Refinery Exemptions

Comment:

Many commenters supported EPA's proposed projection of zero gallons of exempt gasoline and diesel volumes in 2023–2025. Several of these commenters, however, stated that EPA could only justify using a zero projection if it in fact followed through on its proposed denial of all pending SRE petitions, and that to do otherwise would be arbitrary and capricious. These commenters also stated that EPA must account for "retroactive" SREs (i.e., exemptions that are granted after the standards are established) so long as the possibility of granting them exists. The commenters stated that using a zero projection was arbitrary unless EPA makes clear that it will not grant any "late" SRE petitions.

Response:

Consistent with the proposed rule, we are finalizing a projection of zero gallons of exempt gasoline and diesel fuel for 2023, 2024, and 2025. In two separate actions, EPA denied 105 pending SRE petitions for 2016-2021.[38] As detailed in the SRE Denials, EPA has determined that all obligated parties recover the cost of acquiring RINs (i.e., RIN costs) through the higher prices of gasoline and diesel fuel that they sell. Based on EPA's current understanding of the market, and absent a sufficient showing otherwise, no obligated party—including small refineries—experiences disproportionate economic hardship (DEH) caused by its RFS compliance, which is the only basis for which EPA can grant an SRE. Therefore, it is appropriate that we project that no SREs will be granted for 2023, 2024, and 2025.

Comment:

Several commenters opposed EPA's proposed projection of zero gallons of exempt gasoline and diesel volumes in 2023–2025, as it presupposes that EPA will never grant an SRE in the future. These commenters argued that EPA's underlying analysis in its April and June 2022 SRE Denial Actions were faulty and will ultimately be overturned by the courts. These commenters further point to a recent report from GAO regarding the price small refineries pay to acquire RINs.

Response:

Contrary to commenters' assertions, our projection of zero exempt gallons does not prejudge the outcome of future SRE petitions. Rather, as discussed in Preamble Section VII, while we will evaluate all future SRE petitions based on the information they provide, and EPA has made clear in the SRE Denials that an extension of the small refinery exemption remains available upon a sufficient showing, we expect that the approach to evaluating SRE petitions presented in the April and June 2022 SRE Denials will continue to apply to SRE petitions for the 2023–2025 compliance years. Consequently, we do not expect that SREs will be granted for 2023–2025, absent a sufficient showing by the petitioning small refineries demonstrating a different

[38] See "April 2022 Denial of Petitions for RFS Small Refinery Exemptions," EPA-420-R-22-005, April 2022; "June 2022 Denial of Petitions for RFS Small Refinery Exemptions," EPA-420-R-22-011, June 2022 (hereinafter the "SRE Denials").

conclusion is appropriate, and a projection of zero gallons of exempt gasoline and diesel for these years is appropriate.

Commenters' arguments about the validity of EPA's analysis of SRE petitions in the April and June 2022 SRE Denial Actions are beyond the scope of this rule, as those are separate and distinct actions apart from this one. Furthermore, EPA has addressed the findings of the GAO report in the EPA Response to Final GAO SRE Report, available at https://www.epa.gov/renewable-fuel-standard-program/epa-analysis-price-rins-and-small-refineries. These comments are not further addressed in this action.

8. *ACE* Remand

8.1 General Comments on Response to *ACE* Remand

Comment:

A commenter suggested that if EPA increases the mandate through a supplemental standard during a time period where demand for fuel is not also increasing, the cost of compliance will increase and cause higher fuel prices.

Response:

While higher renewable fuel volumes do lead to compliance costs for obligated parties, those compliance costs are passed on to consumers resulting in no net increase in costs to the obligated parties. These higher costs to consumers would be reflected in higher fuel prices. We analyze and project the impacts of the renewable fuel volumes, including the 250-million-gallon supplemental standard, in RIA Chapter 10.5.

Comment:

Some commenters suggested that EPA's proposed response was not compelled by the court in *ACE*. Other commenters suggested that EPA's response was "required" by the D.C. Circuit, and that EPA's obligation is to account for the 500 million gallons waived for the 2016 standards.

Response:

The D.C. Circuit, in vacating EPA's waiver of the 2016 total renewable fuel applicable volume by 500 million gallons in the 2014-2016 rule, did not specify how EPA should respond to the court's remand of the 2014-2016 rule. Thus, EPA could take the approach proposed, and being finalized in this action, or some other approach that addresses the court's vacatur. We find that the approach we are finalizing in this action is appropriate and adequately considers the concerns expressed by the court regarding EPA's prior exercise of its waiver authority, but we agree that this exact approach is not required by the D.C. Circuit's decision, which allows for different responses.

Comment:

Some commenters suggested that the approach to the *ACE* remand is not compatible with the statute, which requires EPA to set annual standards prospectively. A commenter suggested that imposing a 2023 standard is not compatible with the CAA which is to be based on projections of future renewable fuel and transportation use. Commenters also pointed to the changing market participants between 2016 and 2023, indicating that this is "inequitable," and could deprive current obligated parties of "due process," and that parties lack "notice that Agency errors in a given year could add new regulatory burdens years later with no basis in the statutory text." The commenter suggested that obligated parties were not on notice of a supplemental standard in response to the remand.

Response:

We discuss EPA's authority to promulgate late and retroactive RFS standards in Preamble Section II.E. It is true that the statute envisions that EPA would promulgate standards prior to every compliance year, consistent with EPA's authority to modify the volumes utilizing the articulated waiver authorities. However, in this uncommon circumstance, a court has vacated EPA's previous action in waiving volumes for the 2016 compliance year and remanded the rule. Our action in promulgating the total renewable fuel standard for 2016 was based on our understanding, at the time, of both our authority under the Clean Air Act to utilize the general waiver authority (i.e., considering downstream factors, such as demand), as well as the contemporary state of the market. However, the intervening court decision in *ACE* means that EPA cannot effectuate the general waiver authority on the basis of inadequate domestic supply as articulated in the 2016 rule and must now address the vacatur of its improper use of that authority. And, EPA continues to have a statutory obligation to "ensure" that the 2016 statutory volumes are met.[39] Therefore, EPA is responding to the Court's decision in *ACE* regarding the proper interpretation of "inadequate domestic supply" in light of our information about the current state of the renewable fuels market. The commenters' claim that EPA should reduce obligations as it intended to do in 2016 is irrelevant in light of the court's vacatur, and in light of the fact that the supplemental standard will be complied with in the realities of the market as it exists in 2023 and therefore must be considered in that context.

While it is likely that there are different participants in the RFS program in 2023 than in 2016, we are confident that the vast majority of the obligated party participants are the same based on recent compliance report data. It is possible that there will be obligated parties in 2023 who were not subject to the standard in 2016. However, it is appropriate to place the obligation on all obligated parties in 2023, even those who were not obligated parties in 2016, because the number of available carryover RINs functions such that each year's obligations are linked to prior year obligations. It would be difficult, and perhaps impossible, to extricate from current compliance obligations those obligated parties who were not part of the RFS program in 2016, given the inter-related nature of compliance from one year to the next. A supplemental standard for 2023 avoids the difficulties associated with reopening 2016 compliance, as discussed in detail in the 2020-2022 proposed rulemaking.[40] Further, as explained in the preamble, the overall programmatic goals are benefitted by this supplemental standard applying the same way as any other 2023 standard on the participants in the 2023 transportation fuel market. Additionally, we have provided all parties who will be subject to the 2023 supplemental standard with notice that this standard will apply to them through this notice and comment rulemaking process.

A commenter suggested that the supplemental standard "could deprive current obligated parties of due process," but failed to identify any such parties or explain exactly how EPA's action would do so, such that we could evaluate the nature, magnitude, or likelihood of such an issue. More generally, 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. The commenter did not affirmatively conclude that the supplemental standard does

[39] See CAA sections 211(*o*)(2)(A)(i), (iii), and 211(*o*)(3)(B)(i).
[40] 86 FR 72436, 72459-72460 (December 21, 2022); see also 87 FR 39629 (July 1, 2022).

or does not deprive obligated parties of due process and did not provide a rationale to support either conclusion for the EPA to consider. Nor did the commenter point to any vested property interest it claims would be deprived by the supplemental standard. There is a presumption that obligated parties must comply with the requirements of the RFS program, and the remanded volumes are part of those requirements. There is no entitlement to avoid compliance with RFS requirements based on EPA's previous waiver of those requirements that was subsequently held to be inconsistent with the statute and vacated and remanded to EPA with instructions to correct its mistake.[41] Moreover, this rulemaking imposes standards applicable to all obligated parties in 2023, 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.[42]

Commenters also noted that obligated parties lacked notice that EPA may impose a supplemental standard at a later time. We disagree. *ACE* was decided on July 30, 2017, after compliance with the 2016 standards were complete. We issued guidance in 2019, prior to compliance with the 2017 standards, stating that we may respond to the *ACE* remand with the use of later year RINs, and that parties should not choose to retain 2016 RINs to comply with an adjusted 2016 standard when making decisions about their compliance demonstrations.[43] We also stated our intent to require the 2023 supplemental standard in the 2020-2022 rulemaking, which proposed and finalized the first of the two supplemental standards.[44] Additionally, EPA has provided notice and an opportunity for public comment through this rulemaking action, as we did in the past rulemaking action for the 2020-2022 annual rule for the first supplemental standard.

Comment:

A commenter suggested that the supplemental volume is not likely to increase ethanol consumption, but instead draw down the RIN bank or cause the use of advanced biofuel to fill the gap. The commenter suggested this would cause D6 RIN prices to go to parity with D4 and D5, resulting in increased overall costs of the program.

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[41] See *Bd. of Regents of State Colls. v. Roth*, 408 U.S. 564, 577 (1972) (concluding that due process for an alleged property right requires that a person "have a legitimate claim of entitlement," not merely "an abstract need or desire" or "a unilateral expectation").

[42] *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).

[43] See https://19january2021snapshot.epa.gov/fuels-registration-reporting-and-compliance-help/enviroflash-announcements-about-epa-fuel-programs_.html#compliance-deadline where we stated "we anticipate that, consistent with the Court's decision, any future action we may take on a past year's renewable fuel standards will take into account the retroactive nature of such future action. For example, without prejudging any future action, we note that we currently believe that it would be appropriate for the EPA to allow use of current-year RINs (including carryover-RINs) to satisfy further obligations, if any, for a past compliance year that may result from the ACE remand. Therefore we do not believe concerns regarding future EPA action on remand should lead parties to retain 2016 RINs that they would otherwise retire for 2017 compliance."

[44] 86 FR 72436, 72437, 72439, 72444 n.51, 72455, 72458-61 (December 21, 2021); 87 FR 39600, 39601, 39603, 39609 n. 55, 39627-31 (July 1, 2022).

Response:

We do not anticipate the supplemental volume will draw down the number of available carryover RINs as described in Preamble Section VI. While we do anticipate that the standard will be met with advanced biofuels, and recognize the possibility that this may result in increased D6 RIN prices, we find that any increased costs are incidental to our obligation to provide a remedy to our past error following the court's vacatur after it found that we inappropriately waived volumes in 2016.

The D.C. Circuit vacated EPA's exercise of the inadequate domestic supply waiver and remanded the rule to EPA for further consideration in light of the court's decision that the statute foreclosed EPA's 2016 approach. The court provided no additional instruction on how EPA must address its vacatur and remand, and the approach EPA is taking is a reasonable one consistent with our discretion under the Act and applicable caselaw. Thus, as proposed, the supplemental standard is a total renewable fuel standard, such that it can be complied with utilizing any RIN type. In 2016, EPA waived 500 million gallons from the total renewable fuel standard only; it is appropriate therefore, to require the supplemental standard volume from the same renewable fuel category.

Comment:

Some commenters suggested EPA should instead return to our proposed response to the remand in the 2020 NPRM; there, EPA proposed to maintain the 2016 volume requirements and impose no additional volume requirement. In particular, the commenters suggested that because EPA cannot induce additional demand for a prior year, EPA should not impose additional requirements either in that year, or in a future year. Another commenter pointed to the supplemental volume as being particularly inappropriate because they believe the 2023 standards are unachievable, and the supplemental standard would exacerbate the problem.

Response:

We have considered the approach proposed in the 2020 annual rule NPRM and have concluded that such an approach would not be appropriate for the reasons discussed in this final rule. EPA still has a statutory duty to "ensure" that the volumes are met. While it is true that we cannot induce additional demand in 2016, imposing a supplemental standard in 2023 is expected to induce additional renewable fuel demand in 2023. In support of the supplemental standard, we have considered obligated parties' ability to obtain RINs to meet that additional demand, and find that an additional 250 million gallons can be used by the market. The market's ability to achieve both the 2023 volumes and the supplemental volume is discussed in Section 6, Preamble Section 6, and RIA Chapter 6. We do not anticipate that a drawdown of the number of available carryover RINs will be required by this action, however, it is an available compliance option for obligated parties as discussed further in Preamble Section 5. Further discussion of our consideration of other alternatives is provided in response to the next comment. The commenter suggested that EPA failed to grapple with what may happen if the agency's predictions of supply are incorrect, and that the volumes in 2023 are already high. We disagree; we have analyzed the renewable fuels market for 2023, and find that the standards, including the supplemental standard can be met. This is further discussed in RIA Chapter 6.2.5., where we analyzed the market data from the first three months of 2023 and find that the market was on track to meet these volumes.

Comment:

Commenters suggested that EPA should instead utilize the cellulosic waiver authority or the general waiver authority to reduce the volume. They suggested that because, in establishing the 2016 standards, EPA did not utilize the full extent of the cellulosic waiver authority to reduce the advanced biofuel and total renewable fuel standards, and instead allowed advanced biofuel to "backfill" for some of the missing cellulosic biofuel volume, that EPA still retains the authority to reduce the total renewable fuel standard by an additional 380 million gallons. They suggested that EPA should instead evaluate a 120 million gallon supplemental standard, not a 500 million gallon standard spread over two years. A commenter suggested this would be "consistent with [EPA's] original determination and intent in the original rulemaking." The commenter also suggested that imposing a 500 million gallon standard over two years "ignores EPA's contemporaneous decisions based on the state of the market going into 2016." Some commenters also suggested that EPA could now waive the total renewable fuel requirement for 2016 under a finding of inadequate domestic supply or severe economic harm. A commenter suggested there was "no supply of 2016-produced biofuel, or RINs." A commenter suggested that EPA should "reduce the advanced and total obligations as originally intended in 2016."

Response:

The commenters who suggested EPA use its cellulosic waiver authority did not specify whether such a waiver would be retroactive or prospective, applied to the 2016 requirements or the 2023 requirements, or how it would be applied in conjunction with a supplemental standard, given what we know now about the renewable fuel actually used in 2016 and the market's ability to meet a 250 million gallon supplemental standard this year. Commenters would like to have it both ways. They argue that EPA should act consistent with the knowledge and information available at the time of the 2016 standards when it declined to exercise the full cellulosic waiver authority, but also that, at the same time, EPA should utilize the cellulosic waiver authority to lessen the amount of the supplemental standard imposed in this action. Instead, we are utilizing the entire scope of information EPA has before it now, including the actual use of renewable fuel in 2016, the appropriateness of the standards as implemented in 2016, and the ability for a 2023 supplemental standard to be met and to remedy our past action which erroneously waived the 2016 total renewable fuel standard.

Commenters, without much explanation, suggested that we should now waive the volume under a finding of inadequate domestic supply based on an "inadequate supply" of 2016 renewable fuel volumes and 2016 RINs. Other commenters suggested that we should waive the volumes on the basis of "severe economic harm" or "inadequate domestic supply." We disagree. Doing so would be inappropriate for several reasons. Our use of the inadequate domestic supply prong of the general waiver authority was the basis for the court's remand in *ACE*. To argue now that there is an inadequate domestic supply, of EPA's own creation due to the passage of time between the initial rule, the court's decision, and this action, would arguably obviate any meaningful response to the remand. We note also that the market provided significantly more than 500 million excess 2016 RINs in 2016, and thus an argument that there were insufficient 2016 RINs would not be based in facts. While we recognize that the factual circumstances have changed between our use of the general waiver authority in the final rule in December 2015, and now, including the passage of time such that 2016 RINs are no longer valid, we have a mechanism to allow for the use of 250 million gallons of total renewable fuel in 2023 (in addition to the additional 250 million gallons already finalized for 2022). Additionally, use of the general waiver authority is discretionary ("The Administrator . . . *may* waive the volumes"). Therefore, even if the statutory criteria (an "inadequate domestic supply" or "severe economic harm") were met, EPA may choose not to waive volumes utilizing those waiver authorities. While there are no valid 2015 and 2016 RINs available to obligated parties to comply with a supplemental 2016 standard, which could amount to an "inadequate domestic supply," or "severe economic harm" were EPA to require compliance with such RINs for the supplemental standard, EPA has the discretion to not impose such a supplemental standard, and not to issue a waiver on the basis of "inadequate domestic supply" or "severe economic harm." In determining whether to exercise the general waiver authority, under a finding of "severe economic harm," we also consider the benefits of the RFS program; any consideration of reductions in the 2016 standards utilizing this authority would thus consider the benefits provided to the biofuels and agricultural industries by maintained volumes. Imposing a supplemental standard in 2023 balances rectifying our error in waiving volumes in 2016 by requiring additional renewable fuel use, without imposing unreasonable burdens on obligated parties.

In evaluating alternatives to the combined 500 million gallon standard required in 2022 and 2023, we previously considered an approach where EPA could have obligated parties comply with a modified 2016 total renewable fuel standard that required an additional 500 million gallons of renewable fuel relative to the 2016 standard promulgated in 2015.[45] However, such an approach (for any number of gallons except zero[46]) would be at a minimum impractical, if not infeasible, to implement. Under the RFS regulations, only 2015 and 2016 RINs can be used to demonstrate compliance with the 2016 standard.[47] However, compliance with a 2016 standard is no longer possible, as RINs only have a 2-year lifespan, and so 2015 and 2016 RINs have long since expired.[48] These expired RINs are invalid and not available for use to comply with any standards. Additionally, to the extent commenters would like EPA to address the *ACE* remand now by requiring a 500-million-gallon supplement at one time, EPA already began to address the *ACE* remand by requiring a supplemental standard of 250 million gallons in 2022, such that the outstanding 'balance' of the erroneously waived 2016 volumes is 250 million gallons.[49] Because of this, we find that we lack authority to require *more* than 250 million gallons at this time.[50]

[45] See 86 FR 72460 (December 21, 2021); 86 FR 72459 (July 29, 2019).
[46] We previously proposed but declined to address the *ACE* remand by requiring zero gallons, which we still believe to be inappropriate. *Cf.* 84 FR 36762 (July 29, 2019) *with* 86 FR 72457-58 (December 21, 2021); 87 FR 39630 (July 1, 2022).
[47] 40 CFR 80.1427(a).
[48] Based on EMTS data, 29 million 2016 RINs remain unretired. Although these RINs still show up in the database as "available," they are all expired.
[49] See 87 FR 39629-30.
[50] See 87 FR 39630.

As we have stated in the past, we believe the burdens associated with altering the existing 2016 total renewable fuel standard are high.[51] To illustrate the burdens associated with such an approach, we considered the steps that would be required to implement a revised 2016 standard. First, we would need to rescind the existing 2016 standard and promulgate a new one. Next, we would need to return all of the RINs used for compliance to the original owners. Once those RINs were unretired (a process that could take several months), trading of those RINs could resume for a designated amount of time before retirements would again be required to demonstrate compliance. Obligated parties could then attempt to comply with a new, higher total renewable fuel standard that included an adjustment to the required total renewable fuel volume to address the *ACE* decision. However, simply unretiring 2016 RINs would not result in sufficient RINs for compliance with the higher standard because obligated parties only retired the RINs necessary for compliance with the previous, lower standard; any excess 2016 RINs were likely used for compliance with the 2017 standard. Furthermore, because the suite of obligated parties is no longer the same as it was in 2016, with some companies no longer in business, the distribution of unretired RINs could be perceived as unfair as well as uneven, highlighting the complexity of attempting to go back in time. This approach would be burdensome and likely infeasible to implement.

To remedy the insufficient 2016 RINs used for compliance with the 2016 standard, we also considered an approach where 2016 RINs used for compliance with the 2017 standards could be unretired and used for compliance with the increased 2016 standard, but this would also reopen 2017 compliance, with cascading impacts on each subsequent year's compliance. Reopening compliance would impose a significant burden on both obligated parties and EPA as described above. Moreover, stakeholders have expressed strong desire for consistent compliance requirements on an annual basis. Having compliance demonstrations for the prior year be completed before requiring compliance with the subsequent year is considered essential to allow obligated parties to properly account for the vintage of the various RINs in their holdings as they develop their compliance strategies and avoid having RINs expire. Therefore, we do not find that it would be appropriate or reasonable to reopen compliance with the 2016 total renewable fuel standard.

Applying a supplemental standard to the 2016 compliance year would also require us to consider whether the obligated gasoline and diesel fuel volumes used in the calculation of the percentage standards would be derived from the projected volumes used in the rulemaking that established the 2016 standards, or instead use the actual obligated gasoline and diesel fuel volumes in 2016. Of these two choices, using the actual obligated gasoline and diesel fuel volumes would more accurately result in the full volume of the adjustment being realized through the retirement of RINs.[52] However, using the actual obligated gasoline and diesel fuel volumes for the supplemental standard would make it inconsistent with the other 2016 standards, and call into question whether the other percentage standards should also be revised to account for actual obligated 2016 gasoline and diesel fuel volumes and compliance revised for all obligated parties. Doing so could also result in the intended volume falling short due to the departure of several

[51] 84 FR 36762, 36788 (July 29, 2019).

[52] The projected 2016 non-renewable gasoline volume and diesel volume used in the rulemaking that set the 2016 standards was 179.33 billion gallons. According to EIA's May 2021 STEO, the actual non-renewable gasoline and diesel fuel consumption volume in 2016 was 179.16 billion gallons.

obligated parties from the market since 2016. We do not believe that it would be appropriate to revise the other 2016 percentage standards when only the total renewable fuel standard is at issue under the *ACE* remand. Applying the supplemental standards to 2023, as we are finalizing in this action avoids this issue.

Further, EPA finalized the first of the two supplemental standards in 2022, with compliance expected to be due on December 1, 2023. Reversing course mid-way through EPA's response to the *ACE* remand when parties are now actively acquiring and retiring RINs to comply with the 2022 supplemental standards would require consideration of the impacts on the market and market participants. Commenters did not opine on the implications of such a reverse course.

It is true that in 2016, EPA could have waived the total renewable fuel volume by an additional 380 million gallons utilizing the cellulosic waiver authority. However, for the same reasons described above, we do not find that going back and adjusting the 2016 standards 8 years after they were established would be appropriate. Even if we could do so, the additional 380 million gallons is insufficient to remedy the entire lost required volume in the 2016 standards as a result of the use of the general waiver authority, and thus would not be a complete solution to the problem. And were we to go back and use our waiver authority, obligated parties would still need to adjust their compliance obligations for 2016, and there would not be any valid 2015 and 2016 RINs for obligated parties to use to come into compliance. We are instead narrowly responding to the remand in this action through a reasonable and measured response which can incentivize additional renewable fuel use, while still ensuring enough renewable fuel is available to obligated parties to come into compliance.

Comment:

A commenter suggested that EPA failed to conduct an analysis of the statutory factors in CAA section 211(o)(2)(B)(ii) for the supplemental volume. The commenter suggested that EPA should consider the 250 million gallon supplemental standard in the "main analysis of the achievability of the 2023 standards."

Response:

The commenter is correct that we did not perform analysis of all of the specified factors in CAA section 211(o)(2)(B)(ii) for the supplemental standard because EPA is not establishing the supplemental standard under CAA section 211(o)(2)(B)(ii) and thus such analysis is not required. We did, however, perform analysis of the achievability of the 2023 standards, including the supplemental standard, and found that the 2023 volumes, inclusive of the supplemental standard, are achievable as discussed in Preamble Section VI.

Comment:

Several commenters supported EPA's action in responding to the *ACE* remand though a second supplemental standard in 2023.

Response:

We agree with commenters who supported the action we are choosing to finalize in this rule.

8.2 Demonstrating Compliance with the 2023 Supplemental Standard

Comment:

A commenter suggested that EPA should allow obligated parties to utilize 2015 and 2016 RINs to comply with the supplemental standard, as those RINs represent actual renewable fuel used in 2015 and 2016, and would reduce the burdens of the supplemental standard. The commenter also suggested that doing so would not be unduly burdensome on EPA and would properly utilize RINs generated in the applicable compliance year.

Response:

First, we proposed that the supplemental standard would be treated as a 2023 standard for compliance purposes, including the appropriate RIN vintages that can be utilized to demonstrate compliance (i.e., 2022 and 2023 RINs). We have done so to ensure all obligated parties subject to compliance obligations in 2023 would have equal access to the RINs necessary for compliance with the supplemental standard as 2023 RINs are freely available in the market. Doing so also allows for increased demand for biofuels in 2023 to remedy the lack of demand for biofuels in 2016 as a result of our improper use of the general waiver authority to reduce the total renewable fuel volume for the 2016 compliance year. We continue to believe that this approach properly balances the burdens and benefits of the supplemental standard.

Second, the commenters' suggested compliance flexibility to allow the use of 2015 and 2016 RINs is inconsistent with the statute and our regulations, and does not further the goals of the RFS. At the most basic level, because the compliance dates for the years in which the 2015 and 2016 RINs were valid is past (i.e. the 2016 compliance deadline and the 2017 compliance deadline), the 2015 and 2016 RINs are now expired and therefore invalid.[53] This treatment of RINs as invalid after the compliance year passes provides certainty to obligated parties and the market, and encourages the use of any carryover RINs at the time of compliance, such that RINs are not left stranded and unused.[54] EPA notified RFS stakeholders in 2019 that we may respond to the *ACE* remand with the use of later year RINs, and that parties should not choose to retain 2016 RINs to comply with an adjusted 2016 standard.[55]

[53] See 40 CFR 80.1431.

[54] 2015 RINs expired at the time of compliance with the 2016 standards on March 31, 2017. 2016 RINs expired at the time of compliance with the 2017 standards on March 31, 2018. *See* "June 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries," EPA-420-R-22-012, June 2022; Brief for Respondent at 32, *Kern Oil & Refining Co. v. U.S. EPA*, No. 21-71246 (9th Cir. Aug. 27, 2021).

[55] See https://19january2021snapshot.epa.gov/fuels-registration-reporting-and-compliance-help/enviroflash-announcements-about-epa-fuel-programs_.html#compliance-deadline where we stated "we anticipate that, consistent with the Court's decision, any future action we may take on a past year's renewable fuel standards will take into account the retroactive nature of such future action. For example, without prejudging any future action, we note that we currently believe that it would be appropriate for the EPA to allow use of current-year RINs (including carryover-RINs) to satisfy further obligations, if any, for a past compliance year that may result from the ACE remand. Therefore we do not believe concerns regarding future EPA action on remand should lead parties to retain 2016 RINs that they would otherwise retire for 2017 compliance."

The commenter suggests that the remaining 2015 and 2016 RINs represent actual renewable fuel used in 2015 and 2016, and should therefore be eligible to be used for compliance with a supplemental standard that corresponds to a 2016 obligation. It is not atypical for excess RINs to remain in a party's EMTS account even after they are expired. They may remain for many reasons, including having been improperly generated, or subsequently determined not to be valid. The commenter characterized the 2015 and 2016 RINs as "overcompliance," but EPA has no way of knowing whether these expired RINs remain unretired in the accounts of parties because they represent real renewable fuel use, or for some other reason, and given the passage of time we would have little or no ability to verify their validity. RINs are often generated in error, and requiring or allowing the use of those RINs without a means to ensure their validity would not be appropriate. As noted previously, while it is true that the market overcomplied with the 2016 standards, that overcompliance was properly addressed through the availability of carryover RINs which all parties had the opportunity to sell or retire ahead of their expiration at the time of the compliance deadline for the 2017 standards.

Additionally, we do not believe that the 39 million 2015 and 2016 expired RINs still in the EMTS accounts of some obligated parties would provide additional liquidity to the market were we to allow them to be used for compliance with the supplemental standard, and in contrast, would only complicate the compliance process. 39 million is a relatively small number of RINs in comparison to the almost 21 billion gallon total renewable standard we are setting for 2023. Any impacts of this additional volume would be marginal. Allowing the use and trading of 2015 and 2016 RINs would increase complexity in the RIN trading process as described below.

The compliance flexibility suggested by the commenter would still increase complexity for EPA and other RIN market participants in the trading, tracking, and retirement of RINs. The commenter suggested that allowing the choice for obligated parties to comply as a 2016 standard or a 2023 standard would avoid the burdens of reopening 2016 compliance and the cascading impacts. While it is true that allowing the option to simply retire 2015 and 2016 RINs to comply with the supplemental standard would not necessitate the opening of compliance for all years from 2015 or 2016 onward, there are significant resource burdens associated with the requested flexibility.

Compliance would be complicated within the EMTS system, and in the associated recordkeeping and reporting submissions. The EMTS system was specifically designed to accommodate the 2-year lifespan of RINs, given the statutory and regulatory requirements. In order to allow the trading of 2015 and 2016 RINs, the system would have to allow the trading of all subsequent compliance year RINs, including 2017, 2018, 2019, and 2020 RINs, all of which are expired and invalid within the current system. The system would thus need to allow for trading of 8 years' worth of RINs across the entire market, resulting in confusion for market participants, unauthorized RIN transactions, and significant difficulty ensuring RIN trades and retirements were proper. This would extend into the 2024 compliance year given the expected compliance deadline, and would be unduly burdensome to EPA and other RIN market participants, including obligated parties. The EMTS system for tracking and verifying RINs is not set up to handle this, and there is no viable means of doing so outside of the EMTS system. Thus, it would create significant confusion and errors to attempt to allow 2015 and 2016 RINs to still be used. The issues are not limited to EMTS. Associated regulations and forms associated with reporting and with recordkeeping and attest requirements would also need to be modified through the notice and comment process, as those requirements and forms are likewise set up to address only the 2-year life of RINs. EPA would need to adjust all of those requirements to accommodate this change. The commenter also pointed to the 2019 compliance reporting deadline for small refineries remaining open after compliance was complete for other obligated parties through September 2022, but this was only possible because the subsequent compliance deadlines for years 2020 and afterward had also been extended to occur after the 2019 compliance deadline such that the proper sequencing of compliance deadlines could occur.[56] The commenter presented several additional justifications for allowing the use of 2015 and 2016 RINs. The commenter suggested that the parties that hold the 39 million 2015 and 2016 RINs, who are primarily small refineries, should be given the opportunity to satisfy a portion of the supplemental standard with these RINs, or to sell such RINs given the "overcompliance." That type of overcompliance is properly remedied through the compliance flexibility of the 2-year lifespan of RINs, not a 3+ year RIN lifespan, which would be beyond the credit lifespan specified in the statute

The commenter notes its own circumstances of retiring RINs during a period of "uncertainty with the administration of the exemption program," as a basis for explaining why it still held 2015 and 2016 RINs when such RINs are expired and invalid. The choice to retire RINs is an individual business decision made by a sophisticated entity. We note that the company could instead have carried forward a deficit while awaiting resolution of its SRE decision. The commenter requests that EPA craft a complicated solution to maximize the benefits of a single company's business decision to allow the use or trading of these expired RINs. We do not believe that doing so is proper.

Furthermore, enabling the use of expired 2015 and 2016 RINs would not change the fact that we would still have to allow compliance with the 2023 supplemental standard with 2022 and 2023 RINs. It is unlikely that a single obligated party holds sufficient 2015 and 2016 RINs to comply with a 2016 supplemental standard alone. Therefore, the obligated party would comply in part with a 2016 supplemental standard and in part with a 2023 supplemental standard. Based on these multiple complications, the approach we are finalizing to address the remand is reasonable and represents an appropriate balancing of the need to respond to the vacatur with concerns about disruption to our implementation of the RFS.

The commenter suggested allowing 2015 and 2016 RINs would "alleviate some of the increased pressure" of the requirements. The commenter also suggests there are benefits to allowing 2015 and 2016 RINs to be used for compliance, including reducing the need for new renewable fuel use in 2023 and reliance on imports of biofuel. We continue to believe that the 2023 supplemental standard associated with the *ACE* remand properly balances the goals of the RFS program and the burdens such an obligation may place on obligated parties. We believe that what the commenter refers to as the "increased pressure" of higher volumes in 2023 is appropriate through the supplemental standard. As stated above, the supplemental standard is intended to result in increased demand for biofuels in 2023 to remedy the reduced demand for biofuels in 2016 as a result of our improper use of the general waiver authority to reduce the total renewable fuel volume, not simply through the use of expired RINs that may not even have been valid. We

[56] See 86 FR 17073 (April 1, 2021) and 87 FR 5696 (February 1, 2022).

believe that this supplemental standard on top of the other 2023 volumes is achievable through additional renewable fuel use in the market. Energy security impacts of this action, including the impacts of the supplemental volume, are discussed in RTC Section 9.1.2 and RIA Chapter 5.

The commenter suggests that simply allowing the use of the expired 2015 and 2016 RINs in addition to 2022 and 2023 RINs to comply with the supplemental standard will avoid many of the burdens associated with reopening 2016 compliance or requiring the use of a scarce number of 2015 and 2016 RINs. However, doing so would make the supplemental standard no longer a 2023 standard, but rather a 2016 standard (that can also be complied with using 2022 and 2023 RINs), which would raise the concerns described above regarding reopening the 2016 compliance year. Even if we do not reopen 2016 compliance for all obligated parties, allowing RIN trades for 2015 onward would unnecessarily complicate the tracking and accounting of RINs in EMTS as described above. Doing so would also likely expand the lifespan of credits (as reflected by RINs) articulated in the statute in CAA section 211(o)(5)(B) by allowing 2015 and 2016 RINs to be used for at least 3 years of compliance. There is no basis to allow for a longer lifespan in this circumstance, where EPA is establishing a supplemental standard that can be met through currently valid RINs.

The commenter suggests that EPA need only reopen the compliance reports from 2016 for those parties who "wish to comply . . . using 2015 and 2016 RINs," and notes EPA's past practice of reopening compliance for small refineries for 2019. We note that our past reopening of the compliance period for small refineries was a unique circumstance, as a result of ongoing uncertainty surrounding the RFS obligations for small refineries while litigation regarding small refinery exemptions remained ongoing.[57] It was done such that the sequencing of compliance is maintained, and future compliance years are not implicated by reopening 2019 compliance; i.e., compliance for 2020 and later years had not yet occurred, and thus reopening compliance for 2019 does not result in cascading impacts on compliance for later years. Were we to reopen 2016 compliance for even some parties, we would also then likely need to reopen 2017, 2018, 2019, 2020, and 2021 compliance, which are currently complete. Reopening compliance in this manner would be extremely disruptive.

The commenter suggests EPA could make the supplemental standard for 2023 or 2016 and allow obligated parties to choose between the standards. "Choosing" between the standards would allow obligated parties to cherry pick the year with the lowest resulting volume, as a 2016 standard would be calculated based on gas and diesel production in 2016, while a 2023 standard would be calculated based on 2023 gas and diesel production. This could result in less than the full 250 million gallon standard being fulfilled as a result of these decisions, which would not "ensure" that the volumes were met. The commenter suggested EPA could waive any shortfall as a result of this cherry picking or from obligated parties that existed in 2016 but are no longer in business using the cellulosic waive authority, but we find it would be contrary to the statutory authority on which we rely for the supplemental standard to design a program that would plan on such a shortfall. Finally, having compliance open simultaneously for both the 2016 compliance year and the 2023 compliance year would likely result in many errors in compliance as the RIN retirement system is not designed to allow for RIN retirements for multiple years at the same

[57] See 87 FR 5696, 5698-9 (February 2, 2022).

time, and allowing the choice of a 2016 standard would raise the same program implementation concerns described above.

Finally, we are still providing obligated parties with the usual scope of flexibilities, including carry forward deficits and the use of carryover RINs. We do not find that an additional flexibility of using expired and invalid RINs from 2015 and 2016 is either necessary or warranted.

9. Economic and Environmental Impacts

9.1 Economic Impacts and Considerations

9.1.1 Costs of the Program

Comment:

A commenter stated that the ethanol replacement value was not included to account for the E10 BOB contained in E15. The commenter also stated that some E15 seems to be match-blended with an E15 BOB as evidenced by a photograph of a fuel dispenser pump with E15, E10 and minimum octane labels shown on the dispenser, and therefore should receive the ethanol replacement value credit as well. The commenter suggested that the ethanol replacement cost of 68.65 cents per gallon used to estimate the ethanol replacement cost seems low relative to the component octane values shown in a previous table.

Response:
For the cost analysis, the ethanol replacement value attributed to the E10 BOB blended to produce E15 is included in the E15 cost when we estimated the RFS program's cost summarized in RIA Chapters 10.4.2 and 10.4.3, and the summary cost tables in those chapters do show a blending cost credit for E15 for the blending of E10 BOB with E15. However, this ethanol replacement cost was not included in Table 10.4.1-1, which summarizes example costs and was solely intended to show E15's marginal cost above E10 (footnote "c" to that table explains where the replacement cost is applied).

We are not aware of any refiners producing a unique BOB for E15 that would allow E15 to benefit from ethanol's replacement value beyond that already received for E10. Refiners adjust the BOB for the downstream addition of 10% ethanol, but not for the additional 5% ethanol. The fact that the resulting E15 fuel is marketed as a higher octane is evidence of this. Otherwise, as with E10, there would be no increase in the minimum octane rating of the fuel beyond 87. Many E15 marketers are marketing its slightly higher minimum octane rating to consumers as an added benefit of E15. However, that is not the same as the ethanol replacement value that results from the production of the BOB.

Ethanol's replacement value varies by the type of gasoline the ethanol is being blended into. Regular grade gasoline sold in the summer months has the highest ethanol replacement value, while premium gasoline sold in the wintertime has the lowest ethanol replacement value. Also, a volatility cost is added on for summertime reformulated gasoline. The various ethanol replacement cost values and the volatility cost type are volume-weighted together based on each respective gasoline type and its respective volume to derive a single national-average ethanol replacement cost.

Comment:

A commenter stated that some of the corn ethanol plant inputs assumptions used in the cost analysis are incorrect or outdated. The commenter provided a reference to USDA data which reports the total quantity of corn oil and dried distiller grains (DDG) produced at US corn ethanol plants. The commenter estimated that DDG production should be 15 pounds per bushel, and distiller corn oil production should be 0.87 pounds per bushel averaged over all corn ethanol plants, and 0.92 pounds per bushel when considering the portion of dry mill corn ethanol plants which produce corn oil. The commenter a provided a capital cost value of $150 million for a newly built 80 million gallon per year corn ethanol plant in Onida, South Dakota and pointed out that this capital cost is lower than what we used, and asserted that we are overestimating the corn ethanol plant capital cost.

Response:

Since the previous rulemaking (Annual Rules for years 2020 to 2022), EPA found updated input assumptions for corn ethanol plants.[58] The consumption estimates for natural gas and electricity, and the production estimates for corn oil and DDG were adjusted based on the values in that report, and it is these revised values which were used in the cost analysis and summarized in the DRIA and continue to be used for the RIA for this action.

We reviewed the USDA data for corn oil and DDG production as suggested by the commenter. We averaged the corn oil and DDG production quantities reported by USDA for February through October 2022 and divided those quantities by the corn ethanol production volumes produced by US corn ethanol plants for the same time period. As stated by the commenter, the corn oil production values were about the same, although slightly higher (0.78 lb/bushel, or 0.27 lb/gal) based on the USDA data, versus the 0.77 value from the recently updated value we recently adopted and used for the proposed rule cost analysis. We conducted a similar analysis for DDG production using the USDA data and estimated that DDG production by corn ethanol plants is 16 pounds per bushel, or 5.6 pounds per gallon. We changed the corn ethanol plant corn oil and DDG production estimates in our final cost analysis to the higher values estimated from the recent USDA data.

We also reviewed the capital cost information for the recent South Dakota dry mill plant and confirmed that the printed literature cites the $150 million cost as described by the commenter.[59] However, we also reviewed an earlier press release by the company prior to the plant's construction and it reported the same value which raises our concern that the company is only repeating the estimated cost to construct the plant, not the actual construction cost.[60] The construction cost of a single corn ethanol plant does not represent the capital cost of all corn ethanol plants due to the diversity in energy source inputs, differences in energy efficiency of those plants and the capital investments required to realize the efficiency improvements and the potential additional cost for capturing carbon dioxide emissions for sequestration which is being adopted by some plants. The dry mill capital cost estimate we used in our cost estimate is from the University of Illinois cost model for modeling the cost of producing corn ethanol, and we believe that the model is likely based on multiple corn ethanol plant construction cost estimates,

[58] Lee, Uisung; Retrospective Analysis of U.S. Corn Ethanol Industry for 2005 – 2019: Implications for Greenhouse Gas Emissions Reductions; Biofuels, Bioproducts and Biorefining; May 4 2021.
[59] Lee, Stephen; Ringneck Energy's ethanol plant finally is up and running; Capital Journal; June 16, 2019.
[60] Lee, Stephen; Ringneck Energy to Begin Construction on South Dakota Ethanol Plant; Capital Journal; July 27, 2017.

reviewed for accuracy, and likely more accurately estimates the construction cost for a typical sized corn ethanol plant. For this reason, we will continue to use the estimated corn ethanol plant construction cost from the University of Illinois cost model for the final rule.

Comment:

A commenter acknowledged that EPA did not accept the results from an analysis by Verleger, for how a change in renewable fuel volumes impacts crude oil prices that were provided in comments by the commenter for a previous RFS rulemaking. However, the commenter stated that EPA should still estimate how increased renewable fuel consumption impacts the price of crude oil.

Response:

We looked into this issue further in response to this and previous comments. To do so we looked at the impact of changes in crude oil demand on crude oil prices from EIA's Annual Energy Outlook. When modeling two different demand cases for its Annual Energy Outlook report, a low economic growth case relative to the reference case, EIA models a reduction in refined product demand between the two cases, and also estimates a lower crude oil price for the lower demand case relative to the reference case. The low economic growth AEO 2023 case shows a 0.517 million barrel per day reduction in refined product demanded relative to the reference case for the years 2024–2025, and also estimates an average of $0.787/bbl lower crude oil price for the low economic growth case for those same years. Averaged over 2023 to 2025, the Set rule is estimated to cause a 0.127 million barrel per day reduction in gasoline and diesel fuel relative to the No RFS baseline case, and 0.0305 million barrel per day in gasoline and diesel fuel relative to the 2022 baseline case. Assuming the EIA correlation holds, the Set rule volumes would be estimated to cause a $0.18 per barrel decrease in crude oil prices relative to the No-RFS baseline, and a $0.0503 per barrel decrease in crude oil prices relative to the 2022 baseline. If we adopted this method for estimating the RFS program on crude oil prices, it would increase the cost of the RFS program by approximately 1% (if petroleum products become less expensive, the renewable fuels become relatively more expensive).

For two reasons, we elected not to use this method to adjust crude oil prices for the RFS program cost analysis. One reason is that the estimated change in crude oil prices is negligible, and well smaller than the error band of the cost analysis. A second reason is that the low economic growth case represents a lower functioning US economy, so it is not clear if the change in crude oil prices is due to the lower demand or due to the impact of a lower functioning economy being modeled by EIA on crude oil prices (i.e., lower labor rates). Either way, the much larger petroleum market is likely to experience a very, very small price impact due to the relatively much smaller increased volumes of renewable fuels.

Comment:

A commenter stated that E15 reduces fuel costs for consumers because it consistently sells for up to $0.10 per gallon lower than E10 prices. The commenter referred to a recent case when geopolitical tensions in 2022 led to much higher petroleum fuel prices, and lower E15 prices provided consumers with a lower priced option when refueling at retail. The commenter also estimated that if E15 replaced E10 nationwide, that consumer spending on motor fuels would decrease by $20.6 billion.

Response:

When conducting our economic analysis to estimate which fuels would be used without the RFS program in place for the No RFS baseline, we observed that blenders/retailers would not find it economical to sell E15, even though they would find it economical to sell E10. There are two primary reasons why the economics are poorer for E15 compared to E10: The first reason is E15 is blended with E10 BOBs (blendstock for oxygenate blending), and because of this, the 5 percent of additional ethanol in E15 does not receive the fuel blending cost advantage that E10 ethanol does. This benefit is significant and is estimated to be 65 cents per gallon of ethanol blended as E10. The second reason is retailers usually must spend some money, which ranges from thousands of dollars to hundreds of thousands of dollars, to retrofit their retail stations to make their retail station compatible to sell E15. While retailers will often have received a federal cost subsidy in recent years through the USDA Higher Blends Infrastructure Incentive Program (HBIB) program offsetting a portion of this capital cost, they still would need to pay at least a part of this cost for E15 retrofits. We estimated that, post federal HBIB subsidy, that, on average, the amortized retail retrofit cost adds 81 cents per gallon of ethanol for the 5% of ethanol above E10, although there would be a large range for this cost depending on the retail station E15 retrofit cost. When amortizing this retrofit cost over the small incremental 5% volume of ethanol in E15, this cost is significant. Combined with the lack of a blending cost benefit, these two factors normally would cause retailers to price E15 7.3 c/gal above E10 gasoline. Some of this added cost of E15 relative to E10 may not be reflected in retail pricing due to the impact of the RFS program itself. The D6 RIN value helps to reduce the apparent market cost of ethanol considerably. The RIN is not an added cost, but rather a transfer payment within the program and therefore does not show up in our cost analysis. However, it would be expected to impact market pricing. At D6 RIN prices of approximately $1.50 at present, this amounts to 7.5 c/gal, essentially offsetting E15's added costs. Despite this, retailers do often market E15 below that of E10. We believe that retailers have adopted a short-term marketing strategy for E15, hence, they mark the price of E15 lower because it is a relatively new product and they are trying to encourage its sales, and they absorb their losses on other products.

This discussion reflects the cost to the blender/retailer and the price paid by consumers at the pump. However, the cost to consumers must also consider the fuel economy impact of ethanol. Because ethanol has less energy density than gasoline, consuming ethanol fuels also incurs a fuel economy cost. For the cost scenario which we modeled (crude oil prices in the $60 -$70/bbl price range), we estimate that the fuel economy effect to be about $1 per gallon of ethanol. Because E15 contains 5 percent more ethanol than E10, the other fuel option generally available to consumers at retail stations, the fuel economy effect is about 5 c/gal ($1/gal x 0.05) relative to E10. Thus, if a consumer purchases E15 priced 10 cents per gallon lower than E10, they would actually be saving about 5 cents per gallon.

Comment:

A commenter stated that the 5 miles distance estimated used for calculating the cost for transporting renewable biogas from a landfill to a nearby natural gas pipeline, and the estimate that biogas distribution cost in a natural gas pipeline is half of commercial natural gas distribution cost, are both unsubstantiated.

Response:

There are two methods that we found for estimating that the typical length of renewable biogas pipeline for transporting RNG from a landfill to a natural gas pipeline is 5 miles. The first method is by reviewing the Landfill Methane Outreach Program (LMOP) cost model which states that the pipeline distance for this pipeline should be under 10 miles for the model cost estimate to be valid for such projects.[61] The model would be set up to model costs for typical RNG installations. Since the range for the model is between 0 and 10 miles, the average of those two values is 5 miles and likely represents a typical distance for such projects. The second method is the landfill gas database that lists details for landfill projects.[62] Few projects list the pipeline distances to local biogas consumers, including natural gas pipelines. Of those projects which do list pipeline distances, the range is 1/3 to 33 miles, and the average of these projects which lists pipeline distances is 5.5 miles. Based on these two information sources, using 5 miles as the typical RNG pipeline distance for transportation RNG to a natural gas pipeline seems reasonable.

We could not find any data for estimating the cost for distributing the RNG through the natural gas pipeline after the RNG is injected into the pipeline, thus we used engineering judgement. Since landfills are located downstream near urban areas where much of the natural gas is consumed whereas natural gas fields producing natural gas are far from the end-use, using the full natural gas distribution cost would overestimate the distribution cost for RNG. However, the natural gas distribution costs increase as natural gas is distributed downstream through smaller pipelines close to where it is used, thus there still would be more significant costs per distance the gas is transported. For these reasons, we used half of the natural gas distribution cost as a reasonable proxy for the distribution cost of the RNG through a natural gas pipeline.

Comment:

A comment quoted a cost as high as $280,000 to replace pipe dope to make underground piping at retail stations compatible with higher ethanol blends.

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[61] LMOP LFG Energy Tools; LFGcost-Web; Landfill Gas Energy Outreach Program; Environmental Protection Agency, https://www.epa.gov/lmop/list-tools-related-landfill-gas-and-waste-management.

[62] Landfill Gas Energy Project Data; Detailed file of currently operational projects (March 2023); Landfill Gas Energy Outreach Program; Environmental Protection Agency, https://www.epa.gov/lmop/landfill-gas-energy-project-data.

Response:

After we conferred with EPA's Office of Underground Storage Tanks, we estimated a cost of $15,000 and $10,000 per station at E15 and E85 stations, respectively, to make underground storage tank piping compatible with higher ethanol blends. Our cost estimate to upgrade the pipe dope to be compatible with higher ethanol blends is lower than the commenter's cost estimate for two reasons. First, the commenter is likely quoting a cost for a large retail station with many dispensers (i.e., 12 or more) while our cost estimate is solely for a typically sized retail station (i.e., 4 dispensers). Second, our cost is averaged over stations offering higher ethanol blends with different levels of compatibility; as such, the stations which were recently renovated in the last 10 years would already have pipe dope compatible with higher ethanol blends and incur zero piping cost for offering E15/E85. Thus, when taking into account typical station size and not including pipe dope upgrade costs for stations already compatible with higher ethanol blends, the average station pipe dope cost for offering higher ethanol blends is much more modest than that quoted by the commenter.

Comment:

A commenter stated the rule's cost analysis does not take into account the very high inflation rates observed in the last couple of years.

Response:

We do take into account high inflation rates when we estimated the RFS program's costs. First, various renewable fuels feedstock and byproduct prices (vegetable oil, corn, DDGS, crude oil, gasoline, diesel fuel etc.) all use the most recent price projections which capture the price effects of inflation when compared to prices of only a couple years ago. The feedstock prices have the largest impact on the production cost of fuels. Second, the capital cost plant cost index is 34% higher for 2022 than 2019, which accounts for the very high, recently observed inflation effects on the cost to install capital, and would carry over to estimate higher maintenance costs when accounting for fixed costs. The higher renewable fuel costs are offset by higher petroleum fuel costs, which are also impacted by inflation—crude oil costs are 50% higher for the final rule compared to the proposal, and the estimated costs of the RFS program are lower as a result.

9.1.2 Energy Security

Comment:

Many commenters state that this rule will result in energy security benefits and improve the U.S.'s energy independence by requiring more use of renewable fuels in the U.S. transportation sector.

Response:

EPA agrees with the commenters that the increased use of renewable fuels from this rule will increase the U.S.'s energy security and independence by reducing the U.S.'s net petroleum imports. A reduction of U.S. net petroleum imports reduces both financial and strategic risks caused by potential sudden disruptions in the supply of imported petroleum to the U.S., thus increasing the U.S.'s energy security. By reducing U.S. net oil imports, this rule also will modestly move the U.S. towards the goal of energy independence.

Comment:

One commenter states that "fuel shuffling" between sugarcane and corn ethanol as a result of this rule lowers the U.S.'s energy security. Fuel shuffling, according to the commenter, results when Brazil exports sugarcane ethanol to the U.S. to meet RFS Advanced RVOs, while Brazil then backfills ethanol consumption in Brazil with corn ethanol from the U.S. The commenter states that from an energy security standpoint, if corn ethanol qualified as an advanced renewable fuel under the RFS, then there would be energy security benefits to the U.S., since the U.S. would no longer need to import sugarcane ethanol from Brazil to meet the RFS requirements of this rule.

Response:

Per CAA section 211(o)(1)(B), "ethanol derived from corn starch" cannot qualify as advanced biofuel, so the commenter's hypothesis is not relevant to this rulemaking. Regardless, EPA does not know of any methodology that currently estimates the energy security impacts of various specific types of renewable fuels such as corn ethanol produced in the U.S. and sugarcane ethanol produced in Brazil. For example, renewable fuels also may have some energy security risks, for example, as a result of weather-related events (e.g., droughts). Thus, we cannot currently evaluate any differential energy security implications of substituting U.S. corn ethanol for Brazilian sugarcane ethanol. In any case, the amounts of sugarcane ethanol imported to the U.S. as a result of this rule are modest, only 14 million gallons annually. Clearly, any policy that results in more use of U.S. corn ethanol for imported, Brazilian sugarcane ethanol will move the U.S. to the goal of greater energy independence.

Comment:

One commenter raises an energy security issue associated with excess U.S. biodiesel refining capacity. This commenter suggests that petroleum refiners are converting petroleum refineries to renewable diesel production in part due to this rule, which will result in lower demand for biodiesel production. With lower biodiesel demand, according to the commenter, the biodiesel industry will have surplus biodiesel refining capacity. The surplus biodiesel capacity could be used to offset a shortage of domestic (i.e., U.S.) oil refining capacity. The commenter suggests that EPA should implement a higher "nested" volume dedicated to biodiesel within the advanced standard of this rule, which would result in greater biodiesel production and support the greater use of U.S. biodiesel refinery capacity. Thus, an increase in biodiesel demand, by increasing the use of U.S. biodiesel refining capacity, would improve the energy security position of the U.S.

Response:

It is uncertain as to whether setting a higher volume standard for biodiesel production in the nested portion of the advance standard of this rule would improve the U.S.'s energy security position. On the one hand, the greater use of biodiesel production would increase the use of biodiesel refineries. However, the greater use of biodiesel could result in lower demand for renewable diesel. The impact on petroleum refining capacity of lower demand for renewable diesel is even more uncertain as refineries currently considering converting to renewable diesel could instead continue refining petroleum or shut down altogether in response to lower demand for renewable diesel. Thus, it's not clear what the "net" impacts of a higher nested volume dedicated to biodiesel within the advanced standard of this rule would be on overall U.S. refining capacity, and hence, the U.S.'s energy security position. The response to the portion of the comment requesting a nested standard dedicated to biodiesel is contained in RTC Section 4.5.

Comment:

A number of commenters raise issues about the energy security impacts of eRINS in this rule. Some commenters note that this proposed rule did not address the impacts of the use of eRINs on U.S. energy security. Other commenters state that the eRIN proposal would improve the U.S. energy security position by encouraging the wider use of domestically produced renewable biogas and electric vehicles. The wider use of renewable biogas and electric vehicles would result in lower U.S. oil imports and consumption according to these commenters, improving the U.S.'s energy security position. Other commenters state that the wider use of electric vehicles will increase the U.S.'s dependence on foreign supply chains and critical minerals sourced largely outside of the U.S., particularly from China. Increasing the U.S.'s dependence on foreign supply chains and critical materials will reduce the U.S.'s energy security, according to these commenters.

Response:

These comments relate to eRINs, and we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter states that the U.S. is a net oil exporter of crude oil and refined petroleum products, and that the U.S. is also a net importer of biodiesel. The commenter also notes that this rule may result in the U.S. relying on grandfathered sources of foreign biofuels (i.e., palm oil).

Thus, this commenter states that this rule will reduce the U.S.'s energy security. Another commenter suggests that renewable fuels would be imported as a result of this rule. This commenter asserts that there will not be any energy security benefits from reducing U.S. oil imports, since the oil imports will be replaced with imported renewable fuels.

Response:

The U.S. is anticipated to be a net exporter of crude oil and refined petroleum products over the time frame of this rule. However, U.S. refineries still rely on significant imports of heavy crude oil that could be subject to supply disruptions. Also, oil exporters with a large share of global production have the ability to raise or lower the price of oil by exerting the market power associated with the Organization of Petroleum Exporting Countries (OPEC) to alter oil supply relative to demand. These factors contribute to the vulnerability of the U.S. economy to episodic oil supply shocks and price spikes, even when the U.S. is projected to be an overall net exporter of crude oil and refined petroleum products.

Renewable fuels also may have some energy security risks, for example, as a result of weather-related events (e.g., droughts). EPA does not know of any methodology that currently quantifies the energy security impacts of various renewable fuels such as imported renewable fuels. In any case, increases in U.S. renewable fuel imports as a result of this rule would be relatively modest in comparison to the reduction in net U.S. imports of oil from this rule. EPA projects that U.S. renewable fuel imports will offset only four percent of the reduced U.S. net oil imports over the time frame of this final rule, 2023–2025.[63] Thus, 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. Also, since overall imports of liquid fuels to the U.S. are reduced, this rule modestly moves the U.S. towards the RFS goal of increased energy independence.

Comment:

One commenter suggests that EPA's energy security analysis is inaccurate because it focuses on changes in U.S. oil imports, not changes in U.S. consumption. Since oil price shocks are transmitted globally, according to the commenter, countries that consume oil cannot be shielded from the change in world oil prices when world oil supply disruptions occur. Thus, the energy security benefits estimated in this rule are "illusory". In addition, this commenter suggests that changes in military costs to secure oil from unstable parts of the world should not be counted as a benefit for in this rule.

Response:

When more renewable fuels are used as a result of this rule, this reduces both U.S. oil consumption and U.S. oil imports. EPA relies on modeling results from the DOE's Annual Energy Outlook (AEO) 2023 to examine how U.S. oil imports would be influenced by a decline in consumption for oil. As described in RIA Chapter 5.4.1, EPA undertakes a detailed analysis of differences in U.S. oil consumption, crude oil imports/exports, and exports of petroleum products

[63] See the spreadsheet labeled Set FRM Summary - Energy Security Benefits, Import Reductions.

in the 2023–2025 timeframe of this rule using the most recent AEO, AEO 2023. Using this analysis, EPA estimates that roughly all of the change in oil consumption resulting from this rule is likely to be reflected in reduced U.S. net imports of crude oil in the 2023–2025 timeframe of this rule. Reductions in U.S. oil demand rebalances the pattern of oil supplies worldwide, reducing the quantity of oil produced that is subject to likely supply disruptions. From this perspective, the impacts of an oil supply disruption are lessened, which improves the U.S.'s energy security position. We agree with the commenter that military cost changes for securing oil in unstable parts of the world should not be counted as a benefit in this rule, since these possible benefits are too uncertain to quantify.

Comment:

One commenter states that this rule will not have any energy security benefits. According to the commenter, U.S. oil imports are lower than 15 years ago. Second, the commenter suggests that oil imports will be unaffected by this rule. This is so because: (1) the U.S. needs heavier oils for its refineries; (2) the lack of pipeline capacity in certain portions of the U.S. such as California and New England, and (3) some U.S. refineries prefer imported oil supplied by their own company. As a result, the commenter suggests that increased ethanol supply will displace domestic American supplies of oil, not U.S. oil imports.

Response:

We agree that U.S. oil imports are lower than 15 years ago, but the U.S. still imports significant quantities of oil. As a result, there are still energy security benefits from reducing U.S. oil imports. The commenter also mentions a number of factors (i.e., lack of pipeline capacity in various regions of the U.S., U.S. refiners' preference for imported oil etc.) that could result in reductions in domestic oil production instead of U.S. oil imports as a result of this rule. EPA relies on modeling results from the DOE's Annual Energy Outlook (AEO) 2023 to examine how U.S. oil imports would be influenced by a decline in demand for oil. As described in RIA Chapter 5.4.1, EPA undertakes a detailed analysis of differences in U.S. oil consumption, crude oil imports/exports, and exports of petroleum products in the 2023–2025 time frame of this rule using the most recent AEO, AEO 2023. Using this analysis, EPA estimates that roughly all of the change in oil consumption resulting from this rule is likely to be reflected in reduced U.S. net imports of crude oil in the 2023–2025 timeframe of this rule. However, as explained in previous responses, EPA does not agree that this rule has no energy security benefits at all.

Comment:

A number of commenters state that the high costs of RINs from this rule will result in U.S. refinery closures. As U.S. refineries shut down from this rule, the U.S. will become less energy secure, according to these commenters.

Response:

The comments received regarding refinery closure implications of this rule are addressed in RTC Section 9.1.9.

9.1.3 Impacts of Standards on RIN Prices

Many commenters that commented on the impact of the proposed RFS volumes on RIN prices also commented on the impact of RIN prices on fuel prices and refiners. Comments on these topics are covered in RTC Sections 9.1.4 and 9.1.9, respectively.

Comment:

Multiple commenters stated that RFS standards that are higher than the blendwall, such as the proposed volumes, will result in high RIN prices. Other commenters claimed that volumes above the blendwall will result in unpredictable price spikes and RIN price volatility. One commenter stated that EPA must address RIN price volatility.

Response:

We recognize that the implied conventional biofuel volume above the E10 blendwall has a significant impact on D6 RIN prices, with implied conventional biofuel volumes that are above the E10 blendwall generally resulting in higher D6 RIN prices and implied conventional biofuel volumes below the E10 blendwall generally resulting in lower D6 RIN prices.

Because many renewable fuels, including biodiesel, renewable diesel, RNG, and ethanol blended at levels above 10%, cost more to produce and use than the petroleum fuels they displace, some incentive is required to bring these fuels into the transportation fuel pool. Under the current RFS program, RINs incentivize the production and use of renewable fuels and generally represent the marginal cost of increasing renewable fuel use in the transportation sector.

We recognize that it is likely that the volumes we are finalizing in this rule will result in significant (e.g., greater than $0.10 per RIN) RIN prices through 2025 given that the marginal biofuels used for RFS compliance have significantly higher costs than the petroleum fuels they replace, as described in RIA Chapter 10. Higher RIN prices provide greater incentive for the production and use of renewable fuels. At the same time, RIN prices and their volatility 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. Thus, we are not able to confidently project RIN prices in future years.

While EPA has considered these comments regarding the potential RIN price impacts associated with this rule, EPA has not established the volumes in an effort to achieve any pre-determined RIN price. Rather, in establishing the volumes, we abided by our statutory requirements as described in the Preamble and RIA.

Comment:

Multiple commenters stated that pushing the conventional standard above the blendwall would result in high D6 prices because D4/D5 RINs will be needed to meet the shortfall in conventional biofuel. One commenter stated that the convergence of D6 and D4/D5 RIN prices would provide the same incentives for conventional and advanced biofuels, and that this could lead to greater imports of grandfathered biofuels produced from palm oil.

Response:

As described in the Preamble and RIA, in order to meet the 2023–2025 standards EPA anticipates a considerable shortfall in the implied conventional biofuel volume that will then be made up with non-ethanol fuels such as biodiesel and renewable diesel. We therefore expect that D6 RIN prices would converge with D4/D5 RIN prices, consistent with observed RIN prices since 2021. This provides an incentive for growth in both advanced and conventional biofuel volumes. However, as also discussed in the Preamble and RIA, we believe based on the supply of biodiesel and renewable diesel in previous years and the incentives offered in California and states with similar clean fuels programs that the biodiesel and renewable diesel that will be produced and used to fulfill the shortfall in the implied conventional biofuel volume will in fact be advanced biofuel rather than grandfathered biodiesel and renewable diesel produced from palm oil.

Comment:

A commenter stated that setting the conventional volume beyond what can be supplied increases RIN prices and increases the cost of the RFS program.

Response:

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 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 stated that RIN prices are high due to speculation by Wall Street traders.

Another commenter stated that the RIN market is unregulated and easily manipulated, and that the current RIN market benefits large refiners and speculators.

Response:

In evaluating observed RIN prices in previous years, we found that RIN prices generally reflect the marginal cost of biofuels relative to the cost of the fuels that they replace. Similarly, we found that RIN prices and their volatility 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.

We recognize that individual RIN holders may make decisions to sell or hold RINs based on their expectations of future RIN prices. However, individual parties generally do not hold sufficient RINs such that their decision to hold RINs results in RIN shortages or significantly impacts RIN prices. Some parties may choose to hold RINs if they believe the RIN price will increase in the future. While this may be profitable for these parties if RIN prices increase, it also has the potential to result in losses if RIN prices decrease. Speculating on the RIN market in this way carries inherent risk given the potential for RIN prices to increase or decrease, and the fact that RINs have a relatively short useful life (e.g., they can only be used to demonstrate compliance for the year in which they are generated, or the following year in a limited quantity). We are not aware of concrete evidence demonstrating that speculation in the RIN market is appreciably impacting RIN prices.

It is worth highlighting that EPA finalized new RFS regulations that project SRE volumes and reallocate those volumes to other program participants beginning with the 2020 compliance year, helping to ensure a consistent demand for RINs (and the associated renewable fuels) and, through that consistent demand, more consistent and predictable RIN prices.

Comment:

A commenter stated that higher RIN prices represent additional funding for the expansion of biofuel production and use.

Response:

Because many renewable fuels, including biodiesel, renewable diesel, RNG, and ethanol blended at levels above 10%, cost more to produce and use than the petroleum fuels they displace, some incentive is required to bring these fuels into the transportation fuel pool. Under the current RFS program, RINs incentivize the production and use of renewable fuels, and generally represent the marginal cost of blending additional volumes of renewable fuel.

Comment:

A commenter stated that the system set up by EPA where integrated refiners have excess RINs while independent refiners are short on RINs together with a scarcity of RIN results in high RIN prices.

Response:

In developing the RFS program, EPA created a system wherein renewable fuel producers could generate RINs that represent qualifying renewable fuel. These RINs could be separated from renewable fuel under certain conditions and traded to other parties. Obligated parties demonstrate compliance with their RFS obligations by acquiring and retiring RINs. The RIN system created by EPA allowed obligated parties that were generally not engaged in blending renewable fuels to purchase RINs from parties who blended renewable fuels in excess of their obligations, rather than requiring that all refiners physically blend renewable fuels to meet their obligations.

In response to concerns that the RIN system disadvantaged independent refiners who often acquire RINs to meet their RFS obligations by purchasing RINs rather than blending renewable fuels EPA considered, and ultimately denied, petitions for rulemaking to change the RFS point of obligation.[64] As we explained in our 2017 Point of Obligation Denial, EPA has conducted a detailed technical analysis and does not agree with these claims. EPA's RIN discount and RIN cost passthrough analysis was upheld by the D.C. Circuit in consolidated petitions for review of the 2017 Point of Obligation Denial.[65] Since then, EPA has regularly reviewed the available fuels market and RIN price data. EPA has continued to assess available data on this issue in the context of small refinery exemption petition requests and in recent RFS rules. This data continues to support our conclusions that all parties have the same cost to acquire RINs and that RIN costs and the RIN discount are generally passed through to blenders and consumers. Therefore, the RFS program does not provide an advantage or disadvantage to any refiner (because all refiners recover the cost of acquiring RINs in the price of the petroleum-based fuels and blendstocks they sell), nor does it advantage non-obligated blenders over refiners (because competition within the fuels market requires these parties to discount the blended fuels they sell to reflect the value of any RINs associated with the renewable fuels in the blends to remain competitive). For our most recent assessment of the impact of the RFS program on refiners, and specifically on small refiners, see the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.[66]

Similarly, the commenter's argument about RIN scarcity statement has been a recurring concern raised by commenters on RFS annual rules for many years. However, after repeated investigations into the market we have not found evidence that RIN prices are high due to a scarcity of RINs. Rather, what we have found is that RIN prices are the same for all market participants with no evidence of a scarcity of RINs or any accompanying impact on RIN prices. RIN prices generally have reflected the marginal cost of biofuels relative to the cost of the fuels that they replace.

Comment:

A commenter claims that Congress only intended RINs to cover the administrative burdens associated with generating and transacting RINs. Conversely, another commenter stated that

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[64] Denial of Petitions for Rulemaking to Change the RFS Point of Obligation. EPA-420-R-17-008, November 2017.
[65] *Alon Refining Krotz Springs et al v. EPA*, 936 F.3d 628 (2019).
[66] June 2022 Denial of Petitions for RFS Small Refinery Exemptions. EPA-420-R-22-011, June 2022.

there is no evidence that RIN prices were intended to be low, and that higher RIN prices are necessary for the RFS to incentivize renewable fuel use.

Response:

EPA is unaware of any evidence that the Congresses that enacted EISA or EPAct intended RIN prices to be low and only associated with the administrative burdens of generating and transacting RINs. In fact, RINs themselves are not specifically identified in the statute. They were created by EPA pursuant to CAA section 211(o)(5) to represent physical volumes of renewable fuel in our implementing regulations to serve the purpose of credits as required by the statute in the form of carryover RINs, as well as a real-time flexible market trading mechanism, and to provide a more flexible and equitable compliance mechanism for obligated parties.

It is clear that one of Congress' purposes in establishing the RFS is to incentivize the growth of renewable fuel use. See, e.g., increasing statutory volumes in CAA section 211(o)(2)(B)(i). Because many renewable fuels, including biodiesel, renewable diesel, RNG, and ethanol blended at levels above 10%, cost more to produce and use than the petroleum fuels they displace, some incentive is required to bring these fuels into the transportation fuel pool. Under the current RFS program, RINs are the mechanism that can be used to incentivize the blending of renewable fuels.

Comment:

A commenter stated that EPA could ensure that cellulosic RINs trade at or near the maximum price (the price of the cellulosic waiver credit plus the price of a D5 RIN) if EPA set the required cellulosic biofuel volumes at levels that are higher than the market's ability to supply cellulosic biofuel. The commenter argues that this approach to establishing cellulosic biofuel volumes would provide price certainty to cellulosic biofuel producers and the greatest environmental benefits.

Response:

We recognize that were EPA to establish the cellulosic biofuel volumes above the market's ability to supply cellulosic biofuel it would likely have the impact on RIN prices described by the commenter. For a further discussion of the statutory requirements regarding the cellulosic biofuel volumes, including a discussion of relevant statutory constraints, see Preamble Section II.C.2. For more on our consideration of a mechanism to stabilize cellulosic RIN prices see RTC Section 2.3.2.

Comment:

A commenter stated that due to EPA's regulatory management failures only a small number of entities hold a huge portion of the RINs.

Response:

The RIN market is an open market and RINs are freely traded. Any market participant can procure and hold RINs and different parties do so to different degrees as a function of their desired business practices. Individual RIN holders may make decisions to sell or hold RINs based on their expectations of future RIN prices. However, individual parties generally do not hold sufficient RINs such that their decision to hold RINs results in RIN shortages or significantly impacts RIN prices. We recognize that some parties may choose to hold RINs if they believe the RIN price will increase in the future. While this may be profitable for these parties if RIN prices increase, it also has the potential to result in losses if RIN prices decrease. Speculating on the RIN market in this way carries inherent risk given the potential for RIN prices to increase or decrease, and the fact that RINs have a relatively short useful life (e.g., they can only be used to demonstrate compliance for the year in which they are generated, or the following year in a limited quantity). We are not aware of concrete evidence demonstrating that speculation in the RIN market is appreciably impacting RIN prices.

9.1.4 Impacts of Standards on Retail Fuel Prices

Comment:

A commenter cited to data presented by a petition in a small refinery exemption request that EPA denied in April 2022. The commenter claims that the petitioner contends that the data shows that RIN passthrough does not occur in their local market. The commenter requests a more in-depth investigation into RIN cost passthrough.

Response:

This explanation has already been made by EPA in the context of the April 2022 Denial of Petitions for RFS Small Refinery Exemptions[67] and again in the June 2022 Denial of Petitions for RFS Small Refinery Exemptions,[68] specifically section IV.D.2. As noted in their comment, in analyzing this data "The petitioner found an extremely strong correlation (R2 = 0.9976) between the calculated E10 price (assuming 100% RIN cost and RIN discount passthrough) and the posted E10 price, demonstrating for this terminal that the RIN value has been fully passed through to wholesale purchasers since 2010." This data is consistent with the broader market data EPA reviewed in evaluating RIN cost and RIN discount passthrough.

Comment:

Multiple commenters stated that RIN prices added $0.20–$0.30 per gallon to fuel prices.

Response:

As discussed in RIA Chapter 10.5, we estimate that the cost of RINs to obligated parties for compliance with the 2023-25 standards is approximately $0.20 per gallon of petroleum fuel. However, this is neither the impact of RINs on fuel prices nor the impact of the 2023-25 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 2-4 c/gal for gasoline and 10-11 c/gal for diesel fuel over the 2023-25 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.

[67] April 2022 Denial of Petitions for RFS Small Refinery Exemptions. EPA-420-R-22-005, April 2022.
[68] June 2022 Denial of Petitions for RFS Small Refinery Exemptions. EPA-420-R-22-011, June 2022.

Comment:

A commenter stated that while EPA characterizes the fuel price impacts of the proposed rule as marginal, these impacts will occur in the face of persistent high inflation.

Response:

Our estimates in RIA Chapter 10.5 of the impact of this rule on fuel prices are roughly 2-4 c/gal for gasoline and 10-11 c/gal for diesel fuel over the 2023-25 period.

Comment:

A commenter stated that government policies should not increase fuel costs to consumers. Another commenter cited to EPA's conclusions in the draft RIN that the proposed volumes would increase fuel prices and requested lower volumes to avoid these higher prices.

Response:

Congress established the RFS program to require increasing volumes of renewable fuel use in transportation fuel over time. They did so in full recognition that it may increase the cost of transportation fuel to consumers. In recognition of concern over the impact of the RFS program on fuel prices, Congress also required that the "cost to consumers" be one of the factors that EPA must consider when establishing volumes in years without statutory volumes. CAA section 211(o)(2)(B)(i)(V). However, it is also only one of several different factors listed by Congress that EPA must consider. As discussed in Preamble Section VI, the volumes we are finalizing in this rule are based on our analysis of the statutory factors, including the cost to consumers of transportation fuel.

Comment:

A commenter claimed that increasing biodiesel blending requirements lowers diesel fuel prices.

Response:

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. The RIN value, together with the federal tax credit and other available state incentives, can allow biodiesel blends to be priced lower than pure petroleum blends. However, that does not mean that biodiesel use is lowering overall diesel fuel prices. Given the significantly higher cost of biodiesel compared to petroleum diesel as discussed in RIA Chapter 10, blending biodiesel increases overall diesel fuel prices.

Comment:

A commenter stated that higher RIN prices do not impact retail fuel prices, according to analyses by EPA and other parties.

Response:

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. However, RIN prices do impact the price of particular fuel blends (e.g. E10, E85, B0, B20, etc.), generally increasing the price for fuels with relatively low renewable content and decreasing the price for fuels with relatively high renewable content. While the RIN prices themselves generally do not increase the price of transportation fuel, requiring increasing volumes of renewable fuel to be used as transportation fuel can increase fuel prices if the renewable fuel costs more to produce than the petroleum-based fuel it displaces. Our estimates in RIA Chapter 10.5 of the impact of this rule on fuel prices are roughly 2-4 c/gal for gasoline and 10-11 c/gal for diesel fuel over the 2023-25 period.

Comment:

A commenter stated that high compliance costs for obligated parties would be passed on to consumers in the form of higher fuel prices.

Response:

EPA has carefully and repeatedly evaluated this issue and agrees 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, most recently in the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.[69] We have found that both the RIN costs and the RIN value (e.g. 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.

Comment:

A commenter stated that fuels markets are extremely competitive, and that all upstream costs and revenue (including RINs) are passed through to retail prices. The commenter stated that RINs allow renewable fuels to be sold at lower prices.

Response:

The commenter's evaluation is consistent with EPA's understanding. EPA evaluated this issue in detail in the Denial of Petitions for Rulemaking to Change the RFS Point of Obligation,[70] and more recently in the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.[71]

[69] June 2022 Denial of Petitions for RFS Small Refinery Exemptions. EPA-420-R-22-011, June 2022.
[70] Denial of Petitions for Rulemaking to Change the RFS Point of Obligation. EPA-420-R-17-008, November 2017.
[71] June 2022 Denial of Petitions for RFS Small Refinery Exemptions. EPA-420-R-22-011, June 2022.

Comment:

A party stated that considering the price impact of D3 RINs on gasoline and diesel may not be appropriate if EPA is directed by the statute to analyze the price impacts of renewable fuels.

Response:

Among other statutory factors, EPA is required to analyze "the impact of the use of renewable fuels on the cost to consumers of transportation fuel."[72] The cost to consumers of transportation fuel is impacted both by the cost of renewable fuels relative to the petroleum-based fuels they displace as well a number of other factors including the impact of RIN prices and the impact of federal and state incentives. Because D3 RIN prices are expected to impact the cost of gasoline and diesel to consumers we believe it is appropriate to consider the impact of RIN prices when establishing the RFS volume requirements for 2023–2025.

Comment:

A party stated that higher RIN prices do not result in higher ethanol consumption.

Response:

As discussed in RIA Chapter 2.1, we project that in the absence of the RFS program the blending of ethanol as E10 would continue, but the blending of E15 and E85 would mostly cease. The incentive provided by the RIN therefore does help support the blending of ethanol at levels above the E10 blendwall as E15 and E85. As discussed in RIA Chapter 6.5, we project that E15 and E85 volumes will continue to grow under the influence of the RFS standards through 2025. Further, while higher RIN prices may have a limited impact on total ethanol consumption, higher RIN prices can have a more significant impact on the consumption of non-ethanol renewable fuels (see RIA Chapter 3 for our assessment of the impact of the volumes we are finalizing in this rule on the use of renewable fuels in the U.S.).

[72] CAA section 211(o)(2)(B)(ii)(V).

9.1.5 Price and Supply of Agricultural Commodities and Farm Income

Comment:

Multiple commenters stated that feedstocks are available to meet growing demand for food, fuel, feed in the United States. One commenter noted that USDA data shows that corn production has increased steadily over time and that there are annual surpluses even with annual increases in ethanol production.

Response:

As we explain in RIA Chapters 6 and 8, we expect there to be sufficient corn to produce the biofuels associated with this final rule, and that a significant amount of corn ethanol produced in the U.S. will continue to be exported for use internationally. Thus, the supply of corn is not a constraining factor in achieving the final volumes.

Corn surplus levels are a result of two factors, the rate of use of corn, which is a function of biofuel demand among other uses, and the production rate, which is largely a function of planted acres, yields, and the weather. Per-acre yields have increased steadily over time with improvements in plant breeding, optimized chemical use, and technological advancements in the equipment used to plant and harvest (to allow tighter row spacing for example). Weather adds a degree of unpredictability to surpluses, despite best planting and harvesting practices. See RIA Chapter 8.4 for additional discussion on the relationship between corn stocks and prices.

Comment:

A commenter noted that the quantity of soy oil devoted to biofuel production has surged in recent years driven by the RFS. Another commenter stated that the proposal would increase soy oil use significantly, leading to additional tightness and price increases beyond what we've already seen in the past two years, which can translate to higher prices of food and other commodities.

Another commenter suggested EPA could avoid further exacerbating the supply crisis conditions the commenter views as being caused by biofuel quotas by setting annual volumes for each year no higher than the agricultural commodity market can supply to meet both biofuel and food sector needs, i.e., the balance point that represents a fully saturated market beyond which price spikes and availability constraints are likely to metastasize into shortages which would further shock prices, constrain ingredient availability, and potentially shut down production of food products. The commenter also points out that animal fats are irreplaceable for some companies, and such companies are competing against a renewable fuel industry that has numerous other options.

A commenter stated that EPA's analysis used outdated data that did not reflect the current supply crisis disrupting the edible oil market and did not alert EPA's leadership to the important considerations that EPA must weigh in setting annual biofuel volumes. The commenter noted that EPA does not explain how it balanced the various statutory factors, or how it arrived at its conclusions.

Other commenters noted that higher soybean yields paired with an increase in domestic crushing capacity directly translates to significant increases in soybean oil stocks that can be used for both fuel and food purposes. One commenter states growth in production of soy oil and other feedstocks justify an increased RVO for the 2023 to 2025 timeframe.

Response:

As described in RIA Chapter 6.2.3, comments submitted by the National Farmers' Union, the American Soybean Association, and Clean Fuels Alliance America indicate significant new domestic soybean crush capacity will come online through 2025, adding a significant amount of additional soy oil to the market.

As we explain in RIA Chapter 8.4, the steep soy oil price increase seen in 2020-2021 was a result of many factors, most notably weather-related events impacting the harvest of soybeans in South America and palm oil in Malaysia. We have updated our price impact analysis to account for the most recent literature, making use of a 2022 paper by Lusk, *et al.*, that suggests there is a slight decrease in soy meal prices as a result of increasing biofuel volumes.[73] Soy oil and related food price impacts are estimated in the final RIA to be higher than previously described, even with the projected decrease in soy meal prices depressing the impact of biofuels overall.

In CAA section 211(o)(2)(B)(ii), Congress gave EPA flexibility by enumerating factors to consider without rigidly mandating the specific steps of analysis that EPA should take or how EPA should weigh the various factors. We describe our assessment of the impact of the use of renewable fuels on food prices in RIA Chapter 8. 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:

A commenter noted that EPA is required by the statute to evaluate agricultural-related issues in cooperation with USDA and stated they did not find any evidence of this coordination in the proposal materials.

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.[74]

[73] Lusk, Jayson L. (2022) Prepared for United Soybean Board, *Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil*.
[74] See "Documentation of Coordination with USDA and DOE," available in the docket for this action.

Comment:

A commenter believes the use of a commodity model with production, crop-to-feed, processing-byproduct-to-feed and resource details within the U.S. would be a great improvement over the highly aggregated models described in the proposed rulemaking. The commenter cites FASOM as such a model and notes it has been used in previous RFS work.

Response:

The feedstocks used in biofuel production (e.g., corn, soybean oil, canola oil, etc.) are globally traded commodities. We therefore do not think it would be appropriate or sufficient to estimate the impact on the price and supply of agricultural commodities using models that only consider domestic impacts and responses to changing demand for biofuels. We recognize that new modeling can help inform our understanding of the impacts of biofuel production on the prices and supply of agricultural commodities. In this final rule we have updated our estimates of the price impacts on agricultural commodities using recent modeling results from Lusk, *et al.*[75]

[75] Lusk, Jayson L. (2022) Prepared for United Soybean Board, *Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil*.

9.1.6 Impacts on Food Prices

Comment:

Commenters are split on the impacts of biofuels on food prices, with some suggesting prices increase in response to increasing biofuel volumes while others suggest they will decrease as a result of high BBD volumes increasing crush capacity, thereby increasing meal availability. Several cite a Purdue University study[76] that indicates that demand for vegetable oils increases meal supply driving down prices.

Response:

EPA has updated its food price impact analysis in RIA Chapter 8.4 to account for the most recent literature, making use of the cited 2022 Purdue paper. This paper suggests there is a slight decrease in soy meal prices as a result of increasing biofuel volumes, though there is a greater increase in soy oil prices as a result of increased biofuel volumes than previously estimated by EPA. Food price impacts are now estimated to be higher than previously thought, even with the projected decrease in soy meal prices depressing the impact of biofuels on food prices.

Comment:

A commenter suggests that EPA is using outdated data, that meal prices are not decreasing, and also does not consider inflation when calculating food prices.

Response:

EPA's consistent practice is to use the most recently published World Agricultural Supply and Demand Estimates (WASDE) projections from USDA at the time of final rulemaking. This final rule makes use of the 2022 WASDE, published in early 2023. As soybeans are sold as a whole bean, and oil prices are increasing, a corresponding decrease in the price of soy meal is evident, as per WASDE. This is reflected in our food price analysis.

Comment:

A commenter suggests that the proposed volumes do not impact food prices, as more ethanol can be produced without impacting the availability of corn for non-ethanol uses, or requiring more land.

Response:

EPA utilized a no-RFS baseline to estimate food price impacts in RIA Chapter 8. This takes into account the effect ethanol has on the commodity price on corn, as well as the more complex effect that soy-based biofuels have on soy oil and soy meal prices. EPA has estimated that

[76] Lusk, Jayson L. (2022) Prepared for United Soybean Board, *Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil*.

ethanol volumes raise corn prices by 3% for every billion gallons, based on literature. This approach is discussed further in RIA Chapter 8.4. EPA also acknowledges in RIA Chapter 8.3 that some ethanol production may come from new sources that do not require new cropland. This is also discussed in section VI.A of the Biological Evaluation, where EPA discusses the amount of corn cropland that could be potentially attributable to the RFS program. Thus, while the ethanol volumes may not entirely drive changes in plantings, they do alter prices, as discussed in RIA Chapter 8.4. Overall, EPA estimates a slight increase in food prices as a result of the 2023-2025 volumes.

9.1.7 Rural Economies

Comment:

Several commenters representing biodiesel producers stated that the proposed biomass-based diesel volumes fall short of the industry's potential and will send a negative signal to the market, which impacts project investments and commodity prices and in turn will be felt throughout the entire economy. Commenters representing farming unions and trade groups state that EPA should use its Set authority to reward investments in the biofuel supply chain and incentivize farmers and stakeholders to continue to take action to meet climate goals.

Response:

For the final rulemaking, we have identified candidate volumes for biomass-based diesel that better represent availability of feedstocks and production capacity through 2025. After considering the statutory factors, we are finalizing significantly higher volumes for biomass-based diesel than proposed. The final biomass-based diesel volumes for 2023-2025 will continue to support rural income. See CAA section 211(o)(2)(B)(ii)(VI). More discussion is available in RIA Chapters 3 and 6.

Comment:

A commenter cited a 2020 Purdue University study[77] that found the RFS program increased farm incomes by several billion dollars over the 2004-2016 time period, which supports rural jobs and economic growth. Other commenters cited analysis by LMC International[78] indicating the biomass-based diesel industry supports billions in economic impact, much of which is in rural areas. The commenters noted that consistent and growing RVOs help farmers maintain and improve their lands and invest in more efficient technologies.

Response:

We agree with the general conclusions of the Purdue University and LMC studies, namely that higher biofuel production directionally benefits rural economies. However, there is significant uncertainty in what proportion of biofuel use is caused by the *RFS standards* in any given calendar year. In many cases, significant biofuel use would occur for economic reasons, regardless of the RFS program. We further discuss this issue in RIA Chapter 2. As a result, the impact of the RFS standards being finalized is just a subset of the impact of all biofuel volumes.

[77] Taheripour, F., Baumes, H., & Tyner, W. E. (2020). Impacts of the U.S. Renewable Fuel Standard on Commodity and Food Prices. https://www.gtap.agecon.purdue.edu/resources/download/10238.pdf.
[78] LMC International. "Economic Impact of Biodiesel on the United States Economy." November 2022.

9.1.8 Jobs and Profitability of Biofuel Producers

Comment:

Multiple commenters representing the soybean production and crushing industries highlighted how investment and expansion in recent years has provided economic and employment growth in rural areas, but that the current proposal fails to support these investments in the longer term. Other commenters, representing biodiesel producers, cited analysis by LMC International indicating that the biomass-based diesel industry supports over 75,000 jobs and $3.6 billion in wages, but stated that EPA's proposed volumes will send a negative signal to their industry, with economic and employment impacts that will be felt throughout the entire economy. Commenters representing farming unions and trade groups note that agriculture-related jobs support rural economies and cannot be outsourced.

Response:

For the final rulemaking, we identified candidate volumes for biomass-based diesel that better represent availability of feedstocks and production capacity through 2025. After considering the statutory factors, we are finalizing significantly higher volumes for biomass-based diesel than proposed. The final biomass-based diesel volumes for 2023-2025 will continue to support rural income. See CAA section 211(o)(2)(B)(ii)(VI). As explained in RIA Chapters 3 and 6, we are projecting relatively stable biodiesel production through 2025, with significant biomass-based diesel growth occuring through renewable diesel production.

We generally agree that increasing renewable fuel volumes support jobs related to biofuel production and the production of underlying feedstocks. However, there are many drivers of biofuel use and production, so not all economic impacts of biofuels can be attributed to the RFS program or its volume requirements. Furthermore, while the comments on employment may provide insights into the potential impacts of biofuels and related industries, they do not provide a complete picture of the impact of a change in biofuel use on employment throughout the whole U.S. economy or even the whole agricultural sector.

Comment:

A commenter suggested that EPA's analysis of the statutory factor of "job creation" is insufficient because it focuses solely on biofuel production and agriculture sectors while excluding impacts on other industries.

Response:

As discussed in RIA Chapter 8.1, attempting to attribute increases or decreases in employment associated with indirectly related industries is fraught with complexity due to factors that include biofuel import/export activity, shifts in agricultural commodity prices, and varying demand for coproducts. Thus, we chose to focus our employment discussion on activity directly related to production facilities while recognizing that the analysis does not estimate total net employment effects. To the extent that biofuel volumes displace domestic use of fossil fuels like gasoline and diesel, data from EIA on production and export of those products suggests that refiners have been able to avoid reducing their production and sales volumes by selling into foreign markets.[79] Further, our assessment suggests that renewable diesel will represent the liquid biofuel with the largest growth. As discussed in RIA Chapter 6.2, much of this volume is expected to come from converted refinery process trains, or construction of additional lines being operated by existing refiners, largely mitigating negative employment impacts on the refining sector.

Comment:

A commenter noted that increased biogas production has potential for significant job creation as new agricultural digesters and gas upgraders are constructed and brought online, stating 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." The commenter stated that RNG operations supported $1.1B in GDP and over $2.5B in sales in 2021, and for projects under construction, RNG capital expenditures supported $1.5B in GDP and over $2.9B in sales.

Response:

The final volumes include significant increases in biogas, as described in RIA Chapter 3. We have added to RIA Chapter 8 additional discussion related to employment in construction of biofuel production facilities, including biogas production.

[79] EIA, Petroleum Supply Monthly, Table 1. Data compiled from May 2023 release and previous versions.

9.1.9 Impact of the Standards on Refiners

Comment:

A commenter stated that recent studies show that refiners cannot pass all RIN costs through to consumers.

Response:

EPA has regularly assessed the ability for refiners to recover the cost of the RINs they acquire in the price of the petroleum products they sell. EPA evaluated this issue in detail in the Denial of Petitions for Rulemaking to Change the RFS Point of Obligation,[80] and more recently in the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.[81] Based on the available market data, including data submitted by individual refineries in the context of requests for small refinery exemptions, we have determined that all refiners are able to pass through the costs of acquiring RINs to consumers and recover the cost of the RINs they acquire in the price of the petroleum products they sell. We also found that across the transportation fuel pool these RIN costs are offset by the pass through of the RIN value associated with the renewable fuels blended into transportation fuel (e.g., the RIN discount) to consumers.

Comment:

Multiple commenters stated that high RIN prices negatively impacted small and independent refiners, or that lower RIN prices benefited these refiners. Some of these commenters stated that high RIN prices would threaten the viability of small and independent refiners. These commenters generally requested that EPA reduce the required volumes to protect jobs at small and independent refiners. Conversely, multiple commenters stated that RIN prices are passed through to consumers and will not negatively impact independent or merchant refiners or put these parties out of business.

A commenter stated that merchant refiners can't generate RINs like larger, integrated refiners and so merchant refiners must purchase RINs for compliance. This commenter claimed that it is arbitrary and irrational for EPA to insist that the RFS program does not cause a disproportionate impact on merchant refiners.

Response:

After repeated investigations into the market we have concluded that refiners recover the cost of acquiring RINs (whether they are acquired by blending renewable fuels or purchasing separated RINs) in the sales price of the petroleum-based fuels they sell. Commenters failed to present new concrete data, analyses, or other new information that warrant EPA reaching a different conclusion. As we explained in our 2017 Point of Obligation Denial, EPA has conducted a detailed technical analysis and does not agree with these claims. Since then, EPA has regularly

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[80] Denial of Petitions for Rulemaking to Change the RFS Point of Obligation. EPA-420-R-17-008, November 2017.
[81] June 2022 Denial of Petitions for RFS Small Refinery Exemptions. EPA-420-R-22-011, June 2022.

reviewed the available fuels market and RIN price data. This data continues to support our conclusions that all parties have the same cost to acquire RINs and that RIN costs and the RIN value are generally passed through to consumers. Therefore, the RFS program does not provide an advantage or disadvantage to any refiner, nor does it advantage non-obligated blenders over refiners. EPA evaluated this issue in detail in the Denial of Petitions for Rulemaking to Change the RFS Point of Obligation,[82] and more recently in the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.[83] Consequently, the economic burden of the RFS program falls on consumers, not refiners.

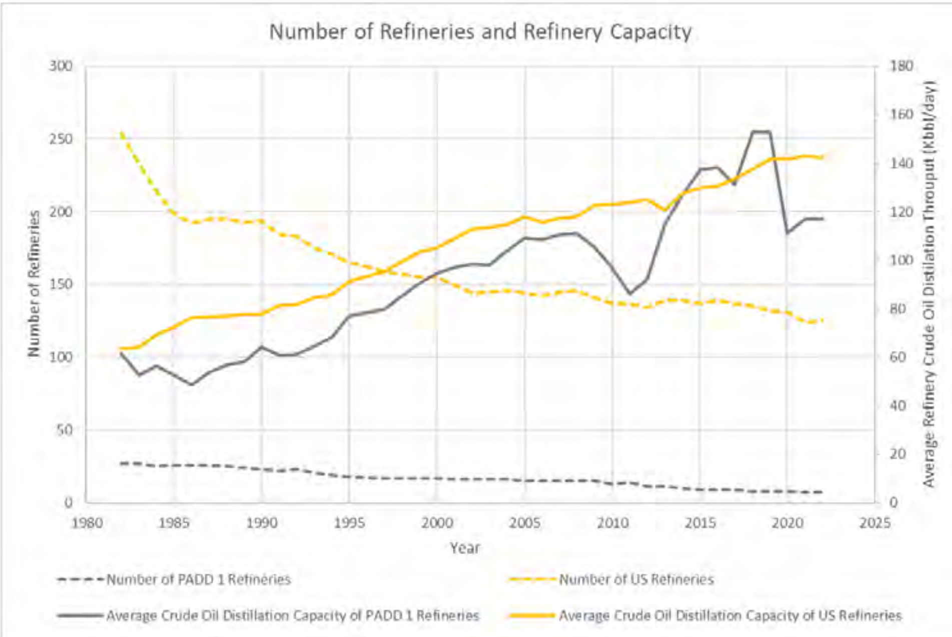
Comment:

As evidence that the RFS program negatively impacted refiners and could cause refinery closures a commenter stated that 15 years ago there were 12 refineries on the east coast, but now only 4 of these refiners are operating.

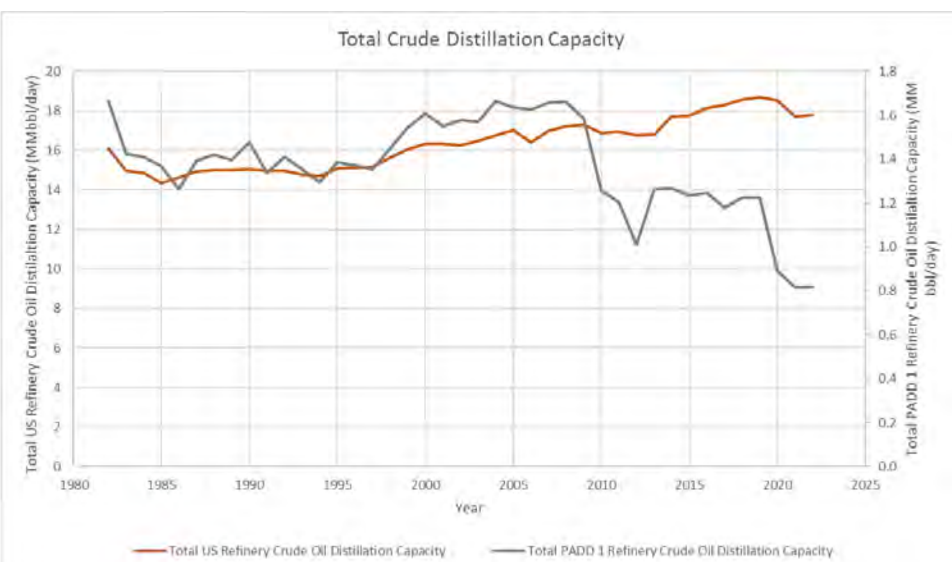
Response:

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.[84] The figure below shows the decline of both total US refineries and PADD 1 refineries from the early 1980s to 2022. While the number of refineries has been declining, US 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.

[82] Denial of Petitions for Rulemaking to Change the RFS Point of Obligation. US EPA (EPA-420-R-17-008), November 2017.
[83] June 2022 Denial of Petitions for RFS Small Refinery Exemptions. US EPA (EPA-420-R-22-011), June 2022.
[84] Meyer, David W. The determination of Plant Exist: The Evolution of the U.S. Refining Industry; Federal Trade Commission Working Paper #328; November 2015. PADD 1 is the petroleum distribution area that includes states along the East Coast.



The figure shows that the total number of US 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 US.



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 these economic impacts, 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.[85] For the most part, PADD 1 refineries needed to rely 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 US 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.[86]

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.

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 percent range, much lower than the typical 90 to 95 percent 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 US 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. However, 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.[87] 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

[85] Shore, Joanne; US Refineries Competitive Position; 2014 EIA Energy Conference; American Fuel and Petrochemical Manufacturers; July 14, 2014.
[86] From the early 2000s until today, the Colonial pipeline increased its throughput capacity from 2.3 to 3.0 million barrels per day; Colonial Pipeline; Wikipedia.
[87] East Coast refiners receiving more domestic crude oil from Gulf Coast by tanker and barge; Today in Energy, Energy Information Administration; September 20, 2018.

which forced this light sweet crude to be used in the US and Canada, causing it to be priced even lower to WTI.

When the US crude oil export ban was ended by Congress at the end of 2015, the US 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 US-produced discounted light sweet crude oils or discounted heavy crude oils.[88] 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 mismanagement of its renewable fuels blending obligations under the RFS program were additional reasons provided for why the company and this refinery struggled.[89] 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 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 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 be attributed to the RFS program.

Comment:

A commenter stated that high RIN prices make it difficult for independent refiners to plan for future investments.

Response:

EPA's assessment of the available market data, including data submitted by individual refineries in the context of our past consideration of petitions to change the point of obligation and small refinery exemption requests, has demonstrated that refiners are able to recover the cost of acquiring RINs in the price of the petroleum-based fuels they sell. Thus, refinery income and profitability are not impacted by RIN prices, and higher RIN prices should not impact a refiner's ability to plan for and finance future investments.

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[88] Crude Oil Markets: Effects of the Repeal of the Crude Oil Export Ban; Government Accountability Index GAO-21-118; October 2020.
[89] Stone, Anthony; After Explosion, Philadelphia Refinery to be Permanently Shutdown; February 17, 2020.

Comment:

A commenter stated that independent refiners are spending more on RINs than anything else other than crude oil.

Response:

It is possible that some refiners are spending more on RINs than expenses other than crude oil, especially when RIN prices are high. However, because refiners are able to recover the cost of acquiring RINs in the price of the petroleum-based fuels they sell, these RIN purchases (or other expenditures to acquire RINs) do not impact the profitability or viability of refiners.

Comment:

Multiple commenters cited to a recent GAO report which they claim found that small refiners pay more for RINs than other refiners.

Response:

EPA has reviewed the Final GAO Report and strongly disagrees with its primary analysis, conclusions, and recommendations with respect to EPA's Small Refinery Exemption (SRE) program. As required by 31 U.S.C. § 720, EPA has submitted to GAO a letter documenting our concerns with GAO's November 2022 Final Report entitled, *Renewable Fuel Standard: Actions Needed to Improve Decision-Making in the Small Refinery Exemption Program* (GAO-23-104273 & GAO-23-105801). The underlying economic data and analysis that are the basis of EPA's conclusions are complex, and we would encourage anyone interested in understanding them to read our response letter[90] and our detailed analysis.[91]

Comment:

Multiple commenters stated that independent refiners must buy RINs at any price and are therefore negatively impacted by high RIN prices. One commenter stated that high RIN prices only benefit larger refiners that sell RINs.

Response:

These commenters are reprising the same arguments that they have made for several years on EPA annual rulemakings and small refinery denial decisions. However, commenters failed to present new concrete data, analyses, or other new information that warrant EPA reaching a different conclusion. As we explained in our 2017 Point of Obligation Denial, EPA has conducted a detailed technical analysis and does not agree with these claims. Since then, EPA

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[90] EPA Response to GAO Report *Renewable Fuel Standard: Actions Needed to Improve Decision-Making in the Small Refinery Exemption Program.* Available at https://www.epa.gov/system/files/documents/2023-05/EPA-Response-to-Final-GAO-SRE-Report-Letter-to-House-and-Senate-Appropriations-Committees.pdf.

[91] An Analysis of the Price of Renewable Identification Numbers (RINs) and Small Refineries. US EPA (EPA-420-R-22-038), December 2022.

has regularly reviewed the available fuels market and RIN price data. EPA recently assessed the prices refiners pay for RINs and found that there is no appreciable difference between the RIN purchase prices for small refiners and large refiners.[92] This data continues to support our conclusions that all parties have the same cost to acquire RINs and that RIN costs and the RIN value are generally passed through to consumers. Therefore, the RFS program does not provide an advantage or disadvantage to any refiner, nor does it advantage non-obligated blenders over refiners. For our most recent assessment of the impact of the RFS program on refiners, and specifically on small refiners, see the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.

Comment:

A commenter cited a press release that claimed that 30% of refinery closures were due to RIN costs.

Response:

As documentation of this claim the commenter cites to a website with information on four petroleum refineries that have been converted to renewable diesel production. We do not believe that the conversion of petroleum refining units to renewable fuel production is necessarily a negative outcome. Arguably such conversions are consistent with the goals of the RFS program.

Further, while we do not contest that the RFS program played a role in the decisions to convert these refineries to renewable diesel production we note that other state and federal incentives and broader market conditions were likely also relevant factors. As highlighted above in the discussion about the impact on PADD 1 refinery closures, there are many market factors that lead to refinery closures over time. U.S. refineries have been closing due to a maturation process which the refining industry has been undergoing over many decades, where more efficient refineries expand, while less efficient refineries shutdown. One reason for this process is that the cost and availability of crude oil and other feedstocks changes has changed over time, which affects the ability for those refineries needing to rely on higher priced feedstocks to compete with the rest of the industry.

[92] An Analysis of the Price of Renewable Identification Numbers (RINs) and Small Refineries. US EPA (EPA-420-R-22-038), December 2022.

9.2 Environmental Impacts and Considerations

9.2.1 GHG Impacts

Comment:

Some commenters said that if EPA is going to update its analysis of the climate change impacts of biofuels for the final rule based on the model comparison exercise described in the proposed rule, then EPA should provide an opportunity for public comment on the outcome of the model comparison exercise and the resulting updated climate change analysis prior to finalizing this rule.

Response:

At the time of proposal, we were contemplating using the model comparison exercise to inform the final rule. See 87 FR 80582, 80611 (Dec. 30, 2022). However, as explained in Preamble Section IV.A.2, we did not ultimately rely on the model comparison exercise to evaluate the candidate volumes or to inform the volumes in this final rule. The model comparison exercise highlighted areas of uncertainty across the models used, a wide range of estimated GHG impacts, and areas for further research.

We describe the model comparison exercise in Preamble Section IV.A.2 for informational purposes only. For informational purposes, we also include the outcome of this exercise in the docket for this rulemaking in the form of the Model Comparison Exercise Technical Document. In a separate process that will be conducted after the conclusion of this rulemaking, EPA intends to solicit feedback and evaluation from outside researchers and organizations on the model comparison exercise. We plan to directly engage with stakeholders to collect input, consider our outstanding research needs in this area, and identify those lines of inquiry most critical to future decisions. Again, the model comparison exercise is being presented in this rulemaking for transparency and awareness only. EPA did not ultimately consider the model comparison exercise in formulating the final rule and any follow-up activities will have no bearing on this rule.

Comment:

Multiple commenters stated that EPA should use the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model from Argonne National Laboratory for lifecycle analysis (LCA) to estimate the lifecycle greenhouse gas emissions associated with the production and use of transportation fuels.

Response:

LCA plays several diverse roles in the context of the RFS program. Under CAA section 211(o)(2)(B)(ii), EPA is required to analyze the climate change impacts of this rule and other RFS rules that establish the renewable fuel standards. This work is related to, but distinct from, EPA's responsibility to determine which biofuel pathways satisfy the lifecycle GHG reduction thresholds corresponding with the four categories of renewable fuel, as specified under CAA sections 211(o) (2)(A)(i) (relating to renewable fuel), (1)(D) (relating to biomass-based diesel), (1)(B)(i) (relating to advanced biofuel), and (1)(E) (relating to cellulosic biofuel).

The multiple comments stating that EPA should adopt GREET are not always clear regarding which of EPA's several GHG analysis responsibilities under the RFS program they believe GREET should be used to satisfy. In the preamble for the proposed rule, we said, "In this rulemaking, EPA is not proposing to reopen the related aspects of the 2010 RFS2 rule or any prior EPA lifecycle greenhouse gas analyses, methodologies, or actions. That is beyond the scope of this rulemaking." 87 FR 80610. Thus, comments stating that EPA should adopt the GREET model to conduct pathway LCA (i.e., LCA for the purpose of determining which biofuel pathways satisfy the lifecycle GHG reduction thresholds corresponding with the four categories of renewable fuel) are outside the scope of this rule. Below we address the comments that are within the scope of this rule, i.e., the comments that say EPA should use GREET to analyze the climate change impacts of this rule pursuant to CAA section 211(o)(2)(B)(ii).

For our analysis of the climate change impacts of this rule, we compile LCA estimates from the scientific literature and multiply the LCA values for each fuel by the change in the volume of that fuel to quantify the greenhouse gas (GHG) impacts. Following this approach, we use the LCA ranges to develop an illustrative scenario of the GHG impacts, which is described and presented in RIA Chapter 4.2.3. LCA estimates from the GREET model are included in our compilation of LCA values from the literature, as they meet the broad criteria for inclusion in this compilation.

For this rule, we believe our approach for analyzing the climate change impacts of this rule, which involves using a range of LCA values from the literature, is more appropriate than using LCA values from any one particular model or study.

In October 2022, the National Academies of Sciences, Engineering, and Medicine (NASEM) completed a report titled "Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States."[93] The NASEM report does not recommend a particular LCA method, model or set of results. The report examined general methodological approaches of LCA, key issues for evaluating GHG emissions, issues that arise for transportation fuels, and methodological issues that arise for characteristic types of transportation fuel. The report includes a number of conclusions and recommendations related to LCA methodologies. For example, Conclusion 2-1 states that, "The approach to LCA needs to be guided on the basis of the question the analysis is trying to answer." Recommendation 4-3 states, "[c]urrent and future LCFS [low carbon fuel standard] policies should strive to reduce model uncertainties and compare results across multiple economic modeling approaches and transparently communicate uncertainties." The recommendations and conclusions from this report indicate that transportation fuel LCA is an area of ongoing scientific research and evaluation. As such, we

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

believe it is appropriate to include a wide range of estimates and study types to inform our analysis for this rule.

While we have not considered the model comparison exercise in developing this final rule, the model comparison exercise we conducted is consistent with the above conclusions and recommendations from the NASEM report. The comparison includes five models, including GREET. We intend to engage with stakeholders to collect input, consider our outstanding research needs in this area, and identify those lines of inquiry most critical to future decisions. The insights from the model comparison exercise may inform future efforts to evaluate the GHG impacts of future RFS rules. Our work related to biofuel GHG modeling and lifecycle analysis will continue after this rulemaking. Given that this scientific process is ongoing, we determined that it would have been premature to select one particular model to conduct the climate change analysis for this rule.

Comment:

Various commenters said that EPA should use the GREET model for LCA of fuels produced from biogas. They say the LCA should include the GHG emissions avoided when animal manure is anaerobically digested relative to other manure treatment methods.

Response:

Our analysis of climate change impacts includes what the commenters are requesting. RIA Chapter 4.2.2 includes our compilation of LCA values from the scientific literature. We include LCA values for CNG produced from landfill biogas and manure biogas. LCA estimates from the GREET model are included for both pathways. For CNG produced from biogas from manure treated in an anaerobic digester, the estimates in the compilation of LCA include studies that estimate the GHG emissions avoided when animal manure is anaerobically digested relative to an assumed baseline scenario where the manure is produced but treated with other methods.

Comment:

Commenters stated that EPA should consider the GHG benefits of climate smart agricultural practices for growing corn and soybeans, such as no-till farming and cover crops. The commenters say that EPA should use the Argonne Feedstock Carbon Intensity Calculator (FD-CIC), a module of the GREET model, to estimate the soil carbon benefits of these agricultural practices.

Response:

In RIA Chapter 4.2.2 we discuss climate smart agricultural practices as follows. We state that climate smart practices are being adopted at the feedstock production stage. For example, planting cover crops between corn rotations can build soil organic carbon stocks. Collecting data on and evaluating these trends in corn and ethanol production are areas for additional effort that will inform future LCA estimates for corn ethanol. Thus, we are considering these trends qualitatively in our analysis. In order to consider these trends quantitively for the purposes of this rule , we believe that additional data and evaluation in the scientific literature would be needed. The GREET FD-CIC module provides an approach to estimate the impacts of these practices at local and regional scales, but we believe more research would be needed to apply this tool for the national and international scale analyses needed for this rule.

Comment:

Commenters stated that EPA should work with Argonne National Laboratory to add green fertilizer production to the GREET model, and consider the GHG benefits of green fertilizer in its LCA of ethanol and other fuel pathways. Examples of green fertilizer mentioned by the commenters include fertilizer produced through a process that uses renewable electricity and carbon capture and sequestration.

Response:

The comments are not always clear regarding which of EPA's several GHG analysis responsibilities under the RFS program they are addressing. In the preamble for the proposed rule, we said, "In this rulemaking, EPA is not proposing to reopen the related aspects of the 2010 RFS2 rule or any prior EPA lifecycle greenhouse gas analyses, methodologies, or actions. That is beyond the scope of this rulemaking." 87 FR 80610. Thus, comments stating that EPA should adopt the GREET model to conduct pathway LCA (i.e., LCA for the purpose of determining which biofuel pathways satisfy the lifecycle GHG reduction thresholds corresponding with the four categories of renewable fuel) are outside the scope of this rule. Insofar as these comments say EPA should add green fertilizer to GREET for purposes of analyzing the climate change impacts of this rule pursuant to CAA section 211(o)(2)(B)(ii), our response is the following paragraph.

EPA currently has an interagency agreement with Argonne National Laboratory to collaborate on further development of the GREET model. We may consider the addition of green fertilizer to GREET as a potential area for collaboration with Argonne.

Comment:

Commenters stated that biodiesel and renewable diesel produced from a range of feedstocks including used cooking oil, soybean oil and canola oil reduce lifecycle GHG emissions by 70% relative to conventional diesel fuel. These commenters cite LCA estimates from the GREET model.

Response:

RIA Chapter 4.2.2 includes our compilation of LCA values from the literature for biodiesel and renewable diesel. Depending on the feedstock and pathway considered, some of the LCA estimates indicate a 70% GHG reduction relative to conventional diesel fuel, while others do not. We consider the range of estimates in the RIA. As discussed above in our response to the commenters that say we should use GREET for LCA, for this rule, we believe our approach for analyzing the climate change impacts of this rule, which involves using a range of LCA values from the literature, is more appropriate than using LCA values from any one particular model or study.

Comment:

Some commenters stated that EPA should not consider the LCA results from a particular study (Lark et al. 2022) in its compilation of LCA estimates in the scientific literature.[94] These commenters say this study is flawed and overestimates the land use change GHG emissions attributable to corn ethanol.

A comment submitted by a federal agency reviews Lark et al. (2022) and concludes that it did not correctly characterize land conversions and overestimated soil carbon losses. The concerns identified include a) failure to account for cropland-to-cropland transitions that occur from the increase in corn ethanol demand, b) the (mis)classification of CRP land as native or longer-term grasslands in soil carbon calculations, and c) using carbon response functions that overestimate emissions from grassland-to-cropland conversions.

Other commenters say EPA should give careful consideration to the results of Lark et al. (2022), which suggest that corn ethanol is associated with greater lifecycle GHG emissions than conventional gasoline.

Response:

For our analysis of the climate change impacts of this rule, we compile LCA estimates from the scientific literature and multiply the LCA values for each fuel by the change in the volume of that fuel to quantify the greenhouse gas (GHG) impacts. Following this approach, we use the LCA ranges to develop an illustrative scenario of the GHG impacts, which is described and presented in RIA Chapter 4.2.3.

Our compilation of corn ethanol LCA values includes the LCA estimates from Lark et al. (2022). However, the illustrative GHG scenario, which forms the basis for our analysis of the overall GHG emissions reductions and monetized GHG benefits of the candidate volumes, does not consider Lark et al. (2022). As discussed in RIA Chapter 4.2.3, the illustrative scenario requires annual streams of emissions over 30 years. Lark et al. (2022) does not provide an annual stream of LCA emissions, nor do any of the other LCA estimates for corn starch ethanol other than the estimates from EPA's March 2010 RFS2 rule. Thus, other than EPA's March 2010 estimates, no other study of crop-based biofuels meets our criteria for the illustrative scenario, nor do they factor into our estimates of the monetized climate benefits of the candidate volumes.

Estimates from Lark et al. (2022) are included in our compilation of LCA values from the literature as this study satisfies our intentionally broad criteria for inclusion in the overall range. As discussed in Preamble Section IV.A.1, given that all LCA studies and models have particular strengths and weaknesses, as well as uncertainties and limitations, our goal for this compilation

[94] Lark, T. J., Hendricks, N. P., Smith, A., Pates, N., Spawn-Lee, S. A., Bougie, M., ... & Gibbs, H. K. (2022). Environmental outcomes of the US renewable fuel standard. Proceedings of the National Academy of Sciences, 119(9), e2101084119.

of literatures estimates is to consider the ranges of published estimates, not to adjudicate which particular studies, estimates or assumptions are most appropriate or of greatest scientific merit. Reflecting the many approaches to LCA and associated assumptions and uncertainties, our review is intentionally broad and inclusive of a wide range of estimates based on a variety of study types and assumptions.

More specifically, Lark et al. (2022) meets the broad criteria for inclusion in our compilation of LCA estimates from the literature for the following reasons. First, it is published in a credible peer-reviewed scientific journal. Second, this study includes LCA estimates for U.S. average corn ethanol, which are precisely the type of estimates we are seeking to compile. Third, this study was published recently, and has not been superseded by a more recent study using the same model or methodology. Finally, it uses a unique analytical approach which supports our goal to include estimates from a wide range of study types. Given that Lark et al. (2022) satisfies our articulated criteria for inclusion in the range of LCA estimates, we do not believe it would be appropriate to single it out for exclusion based on other factors.

Comment:

Commenters stated EPA's illustrative GHG scenario in DRIA Chapter 4 shows the proposed volumes will increase near-term GHG emissions. They say EPA assumes for the illustrative scenario that the biofuel volumes will persist for 30 years, and the longer-term GHG reductions will offset the near-term increases. The commenters say this assumption that the biofuel volumes will persist after 2025 is "dubious," as the current Administration is supporting the adoption of electric vehicles. They say it is possible the U.S. will incur the near-term environmental harms associated with the proposed volumes without obtaining the longer-term environmental benefits.

Other commenters say the near-term pulse of land use change GHG emissions assumed in the illustrative scenario is inaccurate. They say this pulse of land use change emissions will not occur, as the 2023 proposed volume is the same as the 2022 final volume. Furthermore, they say that the pulse of land use change emissions is based on EPA's 2010 analysis, which EPA itself describes as "old."

Response:

RIA Chapter 4.3.2 covers the illustrative scenario for GHG emissions. We intentionally named this scenario "illustrative" as we recognize it depends on multiple assumptions and has several limitations. The ultimate purpose of the illustrative scenario is to estimate the monetized social cost or benefit of the candidate biofuel volumes relative to the No RFS Baseline. Making these estimates requires annual streams of emissions. For the crop-based biofuels that are associated with potential land use change emissions (i.e., corn ethanol, soybean oil biodiesel, soybean oil renewable diesel), the range of LCA values used in the illustrative scenario comes only from EPA's prior LCA modeling for the RFS program, as they are the only estimates in our literature compilation (see RIA Chapter 4.2.2) that report an annual stream of emissions. Based on this approach, the increases in crop-based biofuels for the candidate volumes relative to the No RFS Baseline produce a pulse of near-term land use change emissions in the illustrative scenario. This is a result of the design of the illustrative scenario, and the fact that it relies on our existing LCA estimates for these crop-based pathways.

The scenario is illustrative of what quantified GHG impacts would be if assessed using the LCA values specified in RIA Chapter 4.2.2, applied to the difference between the estimated renewable fuel volumes likely to be used to meet the standards set in this rule and the No RFS Baseline. The illustrative scenario should be interpreted within the context of the assumptions and limitations of applying these LCA values for individual fuels and feedstocks to the analyzed volumes. These limitations include but are not limited to: 1) that EPA's existing lifecycle analyses of crop-based biofuels are dependent on the assumption that biofuel consumption levels remain steady at the assessed volumes for thirty years, even though future consumption levels are inherently uncertain; and 2) that the analyses used do not account for recent (2020 and later) land use data. Nevertheless, we continue to believe that including this scenario provides a useful and appropriate illustration of the potential GHG impacts of the assessed volumes that are likely to be impacted by these standards.

Comment:

Commenters stated the climate impacts of this rule are insignificant. One commenter cites a 2019 report from the Government Accountability Office,[95] in which they say experts agreed that the RFS program had a limited effect on GHG emissions. Another commenter says the climate effects of this rule are too small to have any significant effect on ambient temperature.

Response:

Under CAA section 211(o)(2)(B)(ii), EPA is required to analyze the climate change impacts of this rule and other RFS rules that establish the renewable fuel standards. We believe that the analysis described in RIA Chapter 4.2 adequately satisfies this obligation for this rulemaking.

The GAO report referenced by the commenter based its findings on interviews with a group of thirteen experts. Some of these experts were commenting on the effect of the RFS program on ethanol supplies, which we have addressed in this rulemaking through the development of the No RFS Baseline (see RIA Chapter 2). We believe that our evaluation in RIA Chapter 4.2 appropriately reflects current scientific understandings about the GHG impacts of biofuel production and use through our broad review of LCA estimates in the scientific literature.

Comment:

Commenters stated that biomass-based diesel is a risky climate mitigation strategy that may increase GHG emissions relative to conventional diesel. The commenters say the land use change emissions associated with biomass-based diesel are uncertain, and may be very high. The commenters say corn ethanol is also a risky strategy for the same reasons.

[95] U.S. Government Accountability Office. (2019). Renewable Fuel Standard: Information on Likely Program Effects on Gasoline Prices and Greenhouse Gas Emissions. May 2019. GAO-19-47.

Response:

We believe that our evaluation in RIA Chapter 4.2 appropriately reflects current scientific understandings about the GHG impacts of biomass-based diesel and corn ethanol production and use through our broad review of LCA estimates in the scientific literature. Our literature review provides some support to these comments, as we say in Preamble Section IV.A.1, "The ranges of estimates for non-crop based biofuel pathways tend to be narrower relative to the crop-based pathways." EPA has appropriately taken this information into consideration as part of this rulemaking.

Comment:

A commenter stated that EPA should consider the Forest and Agricultural Sector Optimization Model (FASOM) in its model comparison exercise. The commenter gave a number of reasons that FASOM is appropriate for this type of analysis. The commenter says FASOM includes important details about the U.S. agricultural and forestry sectors that global models lack.

Response:

We requested comment on a number of issues related to the model comparison exercise, including the approach for conducting a model comparison exercise. At the time of proposal, we were contemplating using the model comparison exercise to inform the final rule. See 87 FR 80582, 80611 (Dec. 30, 2022). However, as explained in Preamble Section IV.A.2, we did not ultimately rely on the model comparison exercise to evaluate the candidate volumes or to inform the volumes in this final rule. The model comparison exercise highlighted areas of uncertainty across the models used, a wide range of estimated GHG impacts, and areas for further research. We want to engage with stakeholders and receive feedback on the MCE before deciding whether and how to use any results in a rulemaking context. While we did not ultimately rely on the model comparison exercise to evaluate the candidate volumes or to inform the volumes in the final rule, we are responding to the requested comments here.

Numerous factors influence biofuel GHG estimates, including model framework choice, data inputs and assumptions, and other methodological decisions. In the Model Comparison Exercise (MCE) Technical Document, we discuss the models considered in the MCE: GREET, GLOBIOM, GCAM, GTAP, and ADAGE. This selection of models provides a broad cross-section of the most common types of modeling frameworks used to assess biofuels. We chose to use these models based on discussions with our partners at USDA and DOE and our experience reviewing scientific literature on the lifecycle GHG emissions of biofuels, including for our 2022 biofuel LCA workshop. In addition, our choice to use these particular models is also informed by the statutory definition of lifecycle greenhouse gas emissions in CAA section 211(o)(1)(H), which includes significant indirect emissions, including indirect land use change emissions. Furthermore, in the 2010 RFS2 rule, EPA interpreted this definition as including significant indirect emissions occurring anywhere in the world (i.e., international impacts), as GHG emission impacts are global.

In the MCE, we did not include the FASOM model. Given time and resource constraints, we chose to focus on models with global scope. FASOM is not a global model, and instead covers the continental USA. This exercise was not meant to include every possible model that could be used to estimate biofuel GHG emissions, and omission of a model from this exercise does not preclude its use in the future.

Comment:

A commenter stated EPA must explain how increasing the volume of grandfathered ethanol which does not meet the 20% GHG reduction criterion achieves the purposes of the statute.

Response:

This comment is broad as it speaks to setting volumes and the purposes of the statute. Here, we are responding to the part of this comment that pertains to our analysis of the climate change impacts of the candidate volumes. We want to clarify how our analysis relates to grandfathered ethanol, and to make it clear that our that our climate analysis does not ignore GHG emissions associated with grandfathered ethanol. Our climate change analysis includes a compilation of LCA estimates for corn ethanol from the scientific literature (see preamble Section IV.A.1). For corn ethanol, we include estimates for ethanol produced at a U.S. dry mill facility using natural gas and electricity for energy, as dry mills produce over 90% of U.S. fuel ethanol and natural gas and electricity account for almost all of the energy use at these facilities.[96] These estimates are representative of the GHG emissions associated with average U.S. corn ethanol production. Thus, we believe our analysis is representative of the range of LCA emissions that would be associated with the increase in corn ethanol in the candidate volumes relative to the No RFS Baseline.

Comment:

A commenter submitted a consultant report that proposes a framework with criteria for EPA to evaluate existing LCA methodologies and studies. The report argues that applying criteria to LCA studies from the literature and using only the best available science produces a range of estimates for corn ethanol of 38 to 65 gCO2e/MJ, with an average of 52 gCO2e/MJ, compared to the range of 38 to 116 gCO2e/MJ included in the proposed rule.

Response:

The commenters are correct that we did not use criteria in the proposed rule climate change analysis to give differing weights to the LCA estimates compiled from the literature. We also do not use criteria in this way for the final rule. Instead, our compilation is intentionally broad and inclusive of estimates in the scientific literature. We have not developed a set of criteria against which different studies or models can be assessed, though we recognize that the development and use of such criteria could help to inform future policy decisions. EPA notes that the criteria used to assess different studies or models could vary greatly depending on the context in which

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[96] Lee, U., et al. (2021). "Retrospective analysis of the US corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions." Biofuels, Bioproducts and Biorefining.

lifecycle GHG modeling is being used. For example, the criteria could differ if the context was a holistic program-wide regulatory analysis as opposed to an assessment of individual fuel pathways. Criteria might also differ based on the extent to which fuel volumes from a given individual biofuel pathway appear likely to have impacts on the broader energy or agricultural sectors. To the extent EPA goes on to develop criteria against which we evaluate different studies or models, the Model Comparison Exercise Technical Document, included in the docket for this rulemaking, provides information which will help EPA's work. We plan to directly engage with stakeholders to collect input, consider our outstanding research needs in this area, and identify those lines of inquiry of most importance to future decisions.

We reviewed the consultant report referenced by the commenters. The report applies four "example criteria" to corn ethanol LCA studies: 1) Accepted Approach, 2) Refined Modeling Tools, 3) Complete Data, and 4) Transparent Process. We appreciate this example of how criteria could potentially be applied to judge various studies and models. We believe the report underscores the challenges associated with doing such a review in an objective manner. The example criteria used in this report are relatively subjective, such that different reviewers applying the same criteria to the same studies would likely produce different results. For example, adjectives such as "accepted," "refined," and "reliable" are difficult to apply objectively. As stated above, we recognize that it may be advantageous to develop a set of criteria for assessing LCA models and studies, but we believe additional stakeholder engagement and deliberation is needed before EPA can appropriately develop and apply such criteria.

Comment:

A commenter submitted a consultant report that recommends EPA incorporate additional studies for corn ethanol into its compilation of LCA estimates from the literature. Although EPA's compilation includes studies that estimate GHG emissions associated with corn ethanol lifecycle stages from feedstock production to fuel use, the consultant report recommends adding studies that only estimate land use change emissions associated with corn ethanol production. The report recommends that EPA add these land use change estimates to a value of 43 gCO_2e/MJ representing the other corn ethanol lifecycle stages, based on estimates from GREET. Specifically, the report recommends that EPA add Carriquiry et al., (2019), Laborde (2014), Valin et al. (2015) and Overmars et al. (2015) to its compilation of LCA values for corn ethanol.[97]

Response:

DRIA Chapter 4.2.2.8 included a review of land use change GHG estimates for corn ethanol and soybean oil biomass-based diesel. This review included studies that only estimate the induced

[97] Carriquiry M, Elobeid A, Dumortier J and Goodrich R. 2019. Incorporating sub-national Brazilian agricultural production and land-use into U.S. biofuel policy evaluation. Applied Economic Perspectives and Policy, 42, pp.497-523; Laborde, D., Padella, M., Edwards, R. and Marelli, L., 2014. Progress in Estimates of ILUC with MIRAGE Model. Publications Office of the European Union; Valin, H., Peters, D., Van den Berg, M., Frank, S., Havlik, P., Forsell, N., ... & Di Fulvio, F. (2015). The land use change impact of biofuels consumed in the EU: Quantification of area and greenhouse gas impacts; Overmars, K., Edwards, R., Padella, M., Prins, A.G., Marelli, L. and Consultancy, K.O., 2015. Estimates of indirect land use change from biofuels based on historical data. JRC Science and Policy Report, Ref. no.EUR, 26819.

land use change emissions, excluding emissions associated with other lifecycle stages of production and use. This review in the DRIA includes Carriquiry et al., (2019) and Laborde (2014). It does not include Valin et al. (2015), as the estimates from this study were superseded by ICAO (2021) which includes more recent estimates from the same model.[98] The DRIA does not discuss Overmars et al. (2015), though we have reviewed this report and observe that its estimates are within the range of the estimates reviewed in the DRIA.

We decided not to reproduce the DRIA of review of land use change GHG estimates in the final RIA, as we did not identify significant updates or revisions, and such a review would not factor directly into our compilation of LCA values. Although the RIA does not reproduce the review of land use change-only estimates, it states that, for crop-based biofuels, there are many studies that only estimate land use change GHG emissions; these studies are discussed in DRIA Chapter 4.2.2.8.

RIA Chapter 4.2.2 states that our review of LCA values from the literature focus on studies that estimate full lifecycle (or "well-to-wheel") GHG emissions. We do not add land use change-only estimates to separate estimates of the GHG emissions associated with the other lifecycle stages for the following reasons. First, this approach would create new estimates that are not published in the literature, contrary to the intent of our review. Second, there are ample LCA estimates in the literature for corn ethanol without creating new ones. Third, the approach recommended by the commenter would not expand the range of estimates already included in EPA's compilation. Fourth, a report by the National Academy of Sciences (NASEM 2022),[99] advises caution when combining ILUC estimates with attributional LCA estimates,[100] as the commenter recommends.

Comment:

A reviewer submitted a consultant report that recommends EPA review a report for IEA Bioenergy,[101] "which shows that empirical data does not indicate the association of iLUC with biofuel demand as suggested by older, unrefined agroeconomic models."

Response:

We reviewed the report for IEA Bioenergy recommended by the commenter. We agree with the broad concept of the report that confronting models with empirical data is a good practice for improving models and judging the quality of model estimates. However, the conclusion that,

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[98] ICAO (2021). CORSIA Eligible Fuels -- Lifecycle Assessment Methodology. CORSIA Supporting Document. Version 3: 155.

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

[100] See NASEM (2022), p. 45: "Combining results from different LCA modeling approaches in this manner can complicate the interpretation and use of the CI score." See also Ibid., Recommendation 3-3: "LCA practitioners who choose to combine attributional and consequential LCA estimates should transparently document these choices and clearly identify the implications of combining these different types of estimates for the given application, scope and research question."

[101] IEA Bioenergy. 2022. Towards an improved assessment of indirect land-use change. Task 43 – Task 38. Report, October 2022.

"empirical data does not indicate the association of iLUC with biofuel demand" appears insufficiently supported. It appears that IEA's conclusions are based on comparisons of time series empirical data with modeled estimates of the impacts of a change in biofuel consumption relative to a baseline scenario. We do not believe this is a valid comparison, as statistical methods are needed to estimate causal effects from time series data. We note there are studies that apply such statistical methods and find significant land use impacts associated with a change in corn ethanol production.[102]

Comment:

A commenter stated that estimating indirect land use change (ILUC) is complex and uncertain. They say that although ILUC is uncertain there is a scientific consensus that biofuels lead to significant ILUC. They say it is difficult to choose an ILUC model, but more retrospective analysis would be particularly helpful.

Response:

We agree with the commenter that land use change modeling is complex and uncertain, and this is reflected in the discussion in preamble Section IV.A.1 and RIA Chapter 4.2. We also agree that retrospective analysis would be helpful. For example, statistical studies on historical data are helpful to estimate the causal effects of biofuel production and use.[103] Another example would entail running simulation models in a "hindcast" mode, where the models are set up to simulate the past. The model results are then compared with empirical data for the same time period to measure model performance.[104] Such analyses need to be designed carefully, and they are relatively scarce in the published literature on biofuel GHG emissions. The Model Comparison Exercise Technical Document, included in the docket for this rulemaking,[105] includes our most recent evaluation of land use change modeling and associated uncertainties.

Comment:

A comment stated that the lifecycle GHG emissions associated with biodiesel are lower than such emissions associated with renewable diesel.

Response:

Based on our compilation of LCA estimates, as summarized in RIA Table 4.2.2.13-1, the range of LCA estimates for soybean oil biodiesel is 14-73 gCO_2e/MJ, and the range of estimates for soybean oil renewable diesel is 26-87 gCO_2e/MJ. Thus, consistent with the commenter's observation, our compilation of LCA estimates shows higher GHG emissions for renewable

[102] Li, Y., Miao, R., & Khanna, M. (2019). Effects of ethanol plant proximity and crop prices on land-use change in the United States. American Journal of Agricultural Economics, 101(2), 467-491.
[103] See for example: Li, Y., Miao, R., & Khanna, M. (2019). Effects of ethanol plant proximity and crop prices on land-use change in the United States. American Journal of Agricultural Economics, 101(2), 467-491.
[104] See for example, Calvin, K. V., Snyder, A., Zhao, X., & Wise, M. (2022). Modeling land use and land cover change: using a hindcast to estimate economic parameters in gcamland v2.0. Geoscientific Model Development, 15(2), 429-447.
[105] See Docket ID Number: EPA-HQ-OAR-2021-0427.

diesel relative to biodiesel. This is likely due to the more intensive energy use (hydrogen and natural gas) associated with renewable diesel production relative to biodiesel.

Comment:

A commenter urged EPA to recognize that crops have a land opportunity cost, and EPA must include the carbon opportunity cost of using land to produce biofuel feedstock in its lifecycle calculations. The commenter cites Searchinger et al. (2018) for estimates of the carbon opportunity cost of corn ethanol and soybean oil biodiesel.[106]

Response:

DRIA Chapter 4.2.2.6 cites and briefly summarizes the study referenced by the commenter, Searchinger et al. (2018), as a study that estimates direct land use change emissions associated with biofuel production. The DRIA states, "Direct land use change does not factor into the rest of our review as it has not been used in recent LCA studies; however, it may deserve additional consideration in the future as it can be estimated with empirical measurements instead of counterfactual modeling." RIA Chapter 4.2.2 also considers this study as an example of how GHG emissions for corn ethanol and soybean oil biodiesel could potentially be higher than the upper ends of the compiled LCA ranges. Thus, EPA qualitatively considers the concept of carbon opportunity cost and this particular study in its analysis. RIA Chapter 4.2.2 discusses our reasons for not including the quantitative carbon opportunity cost estimates from Searchinger et al. (2018) in our compilation of LCA ranges from literature.

Comment:

A commenter stated that EPA needs additional time to develop its climate modeling framework and incorporate additional studies on lifecycle GHG emissions of biofuels. They stated economic models are not the appropriate way to do LCA, and the use of economic modeling by EPA and others has also been inconsistent, leading to biased estimates because it does not consider that one gallon of ethanol will not reduce gasoline consumption by one gallon. The commenter stated that the goal of LCA is to mimic what would occur under a perfect global carbon pricing system, and the proper way to do this is to consider the opportunity cost of the land used to produce the fuel.

Response:

There are many areas where additional research would be helpful related to modeling the climate change impacts of a change in biofuel consumption. This is why we conducted a model comparison exercise, the results of which are available in the docket for this rulemaking, which we intend to develop further. Energy market impacts and displacement of petroleum with biofuels is one of the modeling topics discussed in our model comparison. As discussed in the Model Comparison Exercise Technical Document, the models we compared vary in their estimates of indirect energy sector emissions indicating these effects are characterized by

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

significant uncertainties. We believe this is an important area for further research and modeling. As discussed above, we did not ultimately use the outcomes of this model comparison to inform our analysis of the fuel volumes established with this rule. We believe our approach to the climate change analysis for this rule, described in RIA Chapter 4.2, is an appropriate way to consider the available science. This approach involves compiling LCA values from the literature, including LCA estimates that include economic modeling and LCA estimates that do not include such modeling. We also discuss the concept of land opportunity cost in RIA Chapter 4.2.

Comment:

Comments were received about the way EPA estimates the climate benefits based upon the interim estimates of the 'social cost of carbon,' which the comments asserted were analytically and fundamentally flawed. They asserted the stated benefits from reductions in GHG emissions based upon the proposed rule were developed from an illegitimate methodology. The comments asserted that the "opportunity of cost of capital that is the appropriate discount rate to be applied to the evaluation of the proposed rule" rather than the values EPA used.

Response:

EPA disagrees with the commenters' contentions. EPA follows applicable guidance and best practices when conducting its SC-GHG analyses, including OMB Circular A-4 and EPA's Guidelines for Preparing Economic Analyses. We therefore consider our analysis methodologically rigorous, and a best estimate of the projected impacts associated with the final rule. EPA considers the resulting estimates of the SC-GHG analysis to represent appropriate, if conservative, estimates for purposes of this rulemaking.

With respect to the use of opportunity cost of capital for SC-GHG based estimates of climate benefits, the February 2021 IWG TSD discusses in detail why the social rate of return to capital is not appropriate for use in calculating the SC-GHG and climate benefits in general where benefits occur for decades or longer into the future. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends "to ensure internal consistency—i.e., future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." EPA has also consulted the National Academies' 2017 recommendations on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

With respect to discount rates, EPA recognizes the limitations and uncertainties associated with the current interim IWG estimates and underlying methodology. The limitations were outlined in the February 2021 TSD and include that the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower. Additionally, the IAMs used to produce these estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, and the science underlying their "damage functions"—i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages—lags behind the most recent research.

Notably, the modeling limitations do not all work in the same direction in terms of their influence on the SC-GHG estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the SC-GHG estimates likely underestimate the damages from GHG emissions. Therefore, as a member of the IWG involved in the development of the February 2021 TSD, EPA agrees that the interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer reviewed science. The 2021 TSD previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates.

9.2.2 Air Quality

Comment:

Several commenters commented on air quality impacts related to ethanol as a biofuel.

Some commenters noted that the trends show that increased use of ethanol led to a simultaneous reduction in the use of aromatics and olefins and played an important role in combating air pollution. One commenter cited a study by the U. S. Department of Energy that found that CO emissions were lower for 15% ethanol blends (E15) than ethanol-free gasoline (E0), while nitrogen oxide (NOx) and non-methane hydrocarbon (NMHC) emissions were not significantly different.[107] They also cited a 2016 literature review which concluded ethanol is advantageous for both short-and long-term NOx emissions and noted that "many studies have shown the beneficial effects of ethanol blending on fuel [particulate matter] emissions."[108] In addition, commenters noted that EPA's "Fuels Trends Report: Gasoline 2006-2016" shows that refiners have reduced the aromatic content of gasoline and attribute this to ethanol's high octane value. Commenters also stated that the results of an emissions testing study by the University of California-Riverside shows that replacing E10 with E15 results in statistically significant reductions in the emissions of particulate matter, carbon monoxide, NMHC, total hydrocarbons (THC), and other harmful emissions. [109] Other commenters stated that petroleum-based aerosol particles are a significant source of pollution, especially in population-dense urban areas and that disadvantaged communities are disproportionately affected by the negative impacts of petroleum-based fuels on air quality. They said that because renewable fuels displace petroleum fuels, the RFS is playing a direct role in improving the air quality in these communities.

Commenters also stated that ethanol reduces economic and social costs related to health and environment and displaces the most harmful compounds from gasoline aromatic hydrocarbon additives (i.e., benzene, toluene, ethylbenzene, and xylene, or BTEX).[110] They said that increasing the ethanol volume in fuel has a positive impact on tailpipe emissions of toxins, reducing particulates and carbon monoxide. They also pointed out that aromatic hydrocarbons are precursors to the formation of secondary organic aerosols (SOA), which in turn are a major contributor to particulate matter emissions (PM 2.5). They stated that, according to EPA's review for the 2020 Anti-backsliding Study, ethanol does not form SOA directly or affect SOA formation.[111] Furthermore, they indicated that EPA's data shows that aromatics' share of gasoline volume dropped between 2000 and 2016, and that EPA's data demonstrates the air quality and human health benefits of increased ethanol blending in gasoline by replacing harmful

[107] West, B.H., C. S. Sluder, K.E. Knoll, J.E. Orban, J. Feng, Intermediate Ethanol Blends Catalyst Durability Program, February 2012, ORNL/TM-2011/234, http://info.ornl.gov/sites/publications/files/Pub31271.pdf.
[108] Sobhani, S., Air Pollution from Gasoline Powered Vehicles and the Potential Benefits of Ethanol Blending, October 2016.
[109] Comparison of Exhaust Emissions Between E10 CaRFG and Splash Blended E15," June 2022, https://ww2.arb.ca.gov/resources/documents/comparison-exhaust-emissions-between-e10-carfg-and-splash-blended-e15.
[110] Environmental and Energy Study Institute. Ethanol and Air Quality – Separating Fact from Fiction. October 12, 2018. https://www.eesi.org/articles/view/ethanol-and-air-quality-separating-fact-from-fiction.
[111] U.S. Environmental Protection Agency, Clean Air Act Section 211 (v)(1) Anti-backsliding Study, (2020) Appendix A, Page 61. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100ZBY1.pdf.

aromatics with clean octane from ethanol. Finally, they stated that lowering the volume of petroleum in the domestic gasoline pool can reduce health issues related to PM and other emission-based pollutants, which can be accomplished by increasing octane with higher ethanol blends and replacing more hydrocarbon aromatics with ethanol.

Other commenters stated that EPA's analysis in the DRIA comparing emissions per energy unit produced for ethanol versus gasoline is inappropriate, excludes many important pollutants, such as toxic air pollutants, and that EPA cannot isolate the impacts of gasoline.

Another commenter also stated that EPA's analysis in the DRIA overlooks the air quality benefits of ethanol-blended fuels. They stated that EPA should acknowledge the benefits of ethanol-blended fuel in reducing emissions of potent air toxics such as benzene and 1,3-butadiene, as well as particulate matter (PM) and carbon monoxide.[112]

A commenter referenced the DRIA and noted that emissions per BTU produced are much higher for production of ethanol than gasoline, which is a defect of higher RFS volumes. Another commenter cited the Biofuels Report to Congress and noted that results generally show a trend of increased life cycle emissions for criteria pollutants from corn ethanol pathways compared with petroleum-based gasoline. This commenter also noted that increased ethanol use increases the volatility or Reid vapor pressure (RVP) of finished gasoline above levels for those allowed for E0.

Several commenters commented specifically about impacts on air quality from using biodiesel as a transportation fuel.

A commenter stated that biodiesel provides air quality benefits, as its emissions outperform petroleum-based diesel. The commenter states that EPA acknowledges that there are no emissions issues associated with biodiesel for post-2007 vehicles. The commenter then notes that post-2007 vehicles are the majority of the commercial diesel vehicles. Regarding pre-2007 vehicles, the commenter states that there are emission reductions when these vehicles use biodiesel, specifically for total hydrocarbons, CO, and $PM_{2.5}$. The commenter also acknowledges that MOVES shows an increase in NO_X emissions when vehicles use B20. The commenter states that biodiesel provides local air quality benefits and is not a major source emitter of air pollution.[113,114] The commenter asserts that EPA is making a false comparison when comparing emissions per energy unit from biodiesel and distillate fuel since oil refineries are major sources of pollution and there is a disparity in the size of biodiesel plants and oil refineries. In addition, the commenter notes that EPA does not include toxics in its per energy unit comparison for production of biodiesel and distillate fuel.

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[112] See Growth Energy Comments on Proposed Anti-Backsliding Determination for Renewable Fuels and Air Quality, Docket Item No. EPA-HQ-OAR-2020-0240-0012.
[113] Jenny Boeckman, A Permitting Primer, Biodiesel Magazine, Oct. 16, 2007, https://biodieselmagazine.com/articles/1869/a-permitting-primer.
[114] Illinois Soybean Association, Biodiesel improving air quality in Chicago parks, June 22, 2020, https://biodieselmagazine.com/articles/2517050/biodiesel-improving-air-quality-in-chicago-parks.

Another commenter stated that biodiesel reduces PM emissions leading to health benefits and cited a recent study which assessed health benefits from using biodiesel as a transportation fuel and in residential heating oil use.[115] They cite a 45% reduction in cancer risk when legacy heavy-duty trucks, such as older semis, use B100.

Another commenter commented that growth in biodiesel and renewable diesel could help to address clean air concerns in urban communities, including those where emissions from heavy-duty transportation are an acute concern.

One commenter also noted that vehicles that burn biodiesel release harmful particulate matter emissions and have negative impacts on public health outcomes when compared to other low-carbon/zero-carbon transportation methods.[116]

One commenter stated that moving toward natural gas, particularly renewable natural gas (RNG), provides significant air quality benefits compared to diesel fuel.

Response:

In the final rule, EPA continues to find that the air quality impacts associated with this rule are likely minimal. Since the volume changes due to this rule, particularly to ethanol and biodiesel volumes that were the subject of the majority of the comments, are quite small relative to the total consumption of transportation fuel in the U.S., we do not anticipate significant air quality impacts associated with this rule. Given this, and in light of the magnitude of the potential impacts of biofuels on emission rates, even were EPA to fully accept the assertions made by the commenters about the air quality impacts of particular biofuels, it would not provide a sufficient basis to change our judgment as to the final volumes.

EPA also disagrees with the conclusions reached by some of the commenters for an additional, independent reason. While use of biofuels can potentially lead to reduced emissions for some air pollutants and there are studies that can be referenced to support these claims, these commenters failed to adequately acknowledge that the use of biofuels also can potentially lead to increased emissions for these and/or other air pollutants, and there are likewise studies that can be referenced to support these claims. It appears that these commenters selectively focused on studies and individual results from studies favorable to biofuels, while ignoring unfavorable results. As such, EPA finds those commenters' conclusions regarding air quality to be of limited persuasive value.

EPA's assessment of the air quality impacts of this rule is contained in RIA Chapter 4.1. Chapter 4.1 briefly describes available information on air quality impacts of renewable fuels and includes information specific to emissions from production and transport of biofuels as well as end use emissions of liquid biofuels. The end use emissions assessment is based on the MOVES3 emissions model. The MOVES model is a state-of-the-science emission modeling system that

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[115] Trinity Consultants (March 2022), Assessment of Health Benefits From Using Biodiesel As A Transportation Fuel and Residential Heating Oil. https://cleanfuels.org/resources/health-benefits-study.
[116] Jane O'Malley & Stephanie Searle, ICCT, *Air Quality Impacts of Biodiesel in the United States* (2021). https://theicct.org/publication/air-quality-impacts-of-biodiesel-in-the-united-states.

estimates emissions for mobile sources, and it reflects EPA's latest data and modeling on biofuel impacts on vehicle emissions.[117] It is supported by EPA's own 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.[118]

MOVES was also used in EPA's 2020 "anti-backsliding study" (ABS), required under CAA section 211(v)(1). This study provides the most recent EPA assessment of ethanol impacts on vehicle emissions and air quality.[119] The study examined the impacts on air quality from required renewable fuel volumes as a result of changes in vehicle and engine emissions due to the RFS program. Specifically, the study compared two scenarios for calendar year 2016: one with actual air quality impacts of 2016 ethanol and biodiesel volumes from renewable fuel usage (the "with Renewable Fuel Standard (RFS)" scenario) versus another with ethanol and biodiesel air quality that would have resulted in 2016 if renewable fuel usage approximated 2005 levels (the "pre-RFS" scenario).[120] While this study evaluated scenarios with much larger ethanol volume changes than those being finalized in this rule, the results can be used to draw inferences regarding the direction of the emission impacts discussed by the commenters.

Compared to the "pre-RFS" scenario, the 2016 "with-RFS" scenario increased ozone concentrations (eight-hour maximum average) across the Eastern United States and in some areas in the Western United States, with some decreases in localized areas (Figure 8.9a). In the 2016 "with-RFS" scenario, concentrations of $PM_{2.5}$ were relatively unchanged in most areas, with increases in some areas and decreases in some localized areas. The 2016 "with-RFS" scenario increased concentrations of NO_2 in some urban areas. The 2016 "with-RFS" scenario decreased concentrations of CO across the Eastern United States and in some areas in the Western United States, with larger decreases in some areas. Compared to the "pre-RFS" scenario, the 2016 "with-RFS" scenario increased concentrations of acetaldehyde across much of the Eastern United States and some areas in the Western United States and resulted in increases in formaldehyde concentrations. Compared to the "pre-RFS" scenario, the 2016 "with-RFS" scenario decreased concentrations of benzene, and 1,3-butadiene concentrations were relatively unchanged.

EPA's conclusions in the anti-backsliding study are also consistent with our earlier work on the impacts of biofuels on air quality. As part of the RFS2 rulemaking in 2010, EPA conducted a detailed assessment of the emissions and air quality impacts associated with an increase in production, distribution, as well as end use of the renewable fuel volumes sufficient to meet the

[117] https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves.
[118] EPA. 2018. 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. Available at https://www.epa.gov/sites/default/files/2018-09/documents/ethanol-related_request_for_correction_combined_aug_31_2018.pdf.
[119] EPA. 2020. Clean Air Act Section 211(v)(1) Anti-backsliding Study. Report No. EPA-420-R-20-008. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100ZBY1.pdf.
[120] It is important to note that the anti-backsliding study was not required to be a full lifecycle assessment, but rather a detailed assessment of the changes in emissions and air quality at the end use stage of the lifecycle. There are also upstream emission and air quality impacts from the production of renewable fuels and their feedstocks that vary from those of petroleum fuel production that were not taken into consideration as part of the anti-backsliding study.

RFS2 (statutory) volumes, including assumed volumes of biodiesel and ethanol blends.[121] This assessment also indicated both increases and decreases in ambient pollutant levels with increased use of ethanol. The RFS2 RIA indicated that the impact of increased biofuels (as assumed to meet the RFS2 volumes) on PM and some air toxics emissions at the tailpipe was generally favorable compared to petroleum fuels, but the impact on VOCs, NO_x, and other air toxics was generally detrimental.[122] The RFS2 RIA also indicated that the upstream impacts on emissions from production and distribution of biofuel (including biodiesel) were generally detrimental compared to petroleum fuel.[123] Taking tailpipe, upstream, and refueling emissions into account, the net impact on emissions from RFS2 volumes of renewable fuels was increases in the pollutants that contribute to both ambient concentrations of ozone and particulate matter as well as some air toxics. The air quality impacts, however, were highly variable from region to region and more detailed information is available in Section 3.4 of the RFS2 RIA.

More recently, the 2018 Second Triennial Report to Congress summarized existing literature on emissions and air quality impacts. The report did not identify any new information that contradicted previous conclusions. It also noted the magnitude, timing, and location of emissions changes can have complex effects on the atmospheric concentrations of criteria pollutants (e.g., ozone and $PM_{2.5}$) and air toxics, the deposition of these compounds, and subsequent impacts on human and ecosystem health. The Third Triennial Report to Congress on Biofuels is in progress and the AQ impacts summarized in that draft version are consistent with what was in the Second Triennial Report to Congress on Biofuels, see https://cfpub.epa.gov/ncea/biofuels/recordisplay.cfm?deid=353055.

EPA acknowledges new studies available, including the study by University of California Riverside comparing end use emissions from E10 and E15. We expect only limited amounts of E15 to be used through 2025, as described in RIA Chapter 4, and accordingly any air quality impacts are also expected to be limited.

EPA acknowledges that Table 4.1.1-4, which compares emissions per energy unit produced, does not include emission factors for specific toxics, because the data used to generate that table did not include toxics. Chapter 4.1 references a GREET update which allowed EPA to allocate refinery emissions to specific products such as gasoline.[124]

Comments related to environmental justice are addressed in RTC Section 12.2.

[121] See 75 FR 14803-08 (March 26, 2010) and Chapter 3.4 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[122] U.S. EPA. February 2010. RFS2 Regulatory Impact Analysis. EPA-420-R-10-006. Table 3.2-7 and 3.2-8.
[123] U.S. EPA. February 2010. RFS2 Regulatory Impact Analysis. EPA-420-R-10-006. Table 3.2-2 and 3.2-3.
[124] Sun, P., Zhu, L. Emissions Updates for Petroleum Products in GREET 2019, https://greet.es.anl.gov/files/petro_2019.

9.2.3 Water Quality and Quantity

Comment:

Several commenters raised general concerns about water quality and quantity impacts due to the expansion of crops that could be used to produce biofuels.

Several commenters raised concerns on increased pollution due to fertilizers, nutrients and soil erosion and how they may affect water quality. One commenter specifically mentioned a possibility of increased frequency of algal blooms.

Response:

We address water quality and water quantity impacts associated with the renewable fuel volumes in RIA Chapter 4.3. In addition, we note that EPA recognizes the potential impacts on water use and water quality from row crops, especially corn and soy. These impacts are assessed in the May 19, 2023 biological evaluation with the May 31, 2023 addendum (combined, "the May 19 BE").[125] In the May 19 BE, EPA further evaluated the effects that cropland expansion may have on water quality. SWAT analysis from the Draft Third Triennial Report to Congress was used to evaluate pesticide impacts and their effects on water quality and species.

Comment:

Commenters were both concerned and in favor of renewable biofuels from factory farms. One comment suggested that biogas from factory farms may increase damages to water quality. Another comment was in favor of digesters and their positive impact on water quality.

Response:

As stated in the previous comment, discussion of impacts on water quality information can be found in RIA Chapter 4.4. Additional information on biogas from renewable operations such farms and municipalities can be found in RIA Chapter 9.3.

The RFS may, along with the CARB LCFS and other programs, incentivize the use of digesters at concentrated animal feeding operations (CAFOs) for the utilization of renewable biofuels, however, it does not drive the proliferation of CAFOs. 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.

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[125] "Biological Evaluation of the Renewable Fuel Standard (RFS) Set Rule," May 19, 2023 & Email from T. Phillips, EPA, to D. Baldwin, NOAA (May 31, 2023) are both available in the docket for this action.

9.2.4 Ecosystems, Wildlife Habitat, and Conversion of Wetlands

Comment:

Several commenters raised general concerns about ecosystem health, the loss of habitats, and impacts to wildlife and biodiversity due to the expansion of crops that could be used to produce biofuels. For example, several commenters expressed concerns about habitat loss and biodiversity degradation due to increased crop production, especially the production of corn and soy.

A few commenters mentioned potential impacts on threatened or endangered species as part of a general list of environmental impacts, such as biodiversity and habitat loss, that commenters linked to the RFS program, specifically corn, palm oil, and soy oil production.

Response:

EPA acknowledges the commenters' concerns regarding the potential impacts of crop expansion on ecosystem health, habitat loss, wildlife, and biodiversity, and threatened and endangered species. We agree that increases in crop production may be associated with increased pressure to convert grasslands and wetlands into cropland and, therefore, also increased pressure on wildlife habitats. We also recognize that habitat loss and landscape simplification may be detrimental to environmental health with the potential for acute impacts in environmentally sensitive areas. We also agree that attributing environmental impacts to the RFS program or this rule, as opposed to other factors, is difficult.

We discuss our assessment of the potential impacts on conversion of wetlands, ecosystems, and wildlife habitats associated with this rule in RIA Chapter 4.3. We discuss the potential impacts on threatened and endangered species in the May 19 BE conducted in support of EPA's Endangered Species Act (ESA) section 7(a) consultation on this rule.

Comment:

One commenter suggested that grasslands are harmed more by the production of certain renewable fuels than others.

Response:

EPA acknowledges that different types of biofuels may have different impacts on grassland, wetlands, ecosystems, and wildlife habitats, as described in RIA Chapter 4.4. We agree with the commenter that biofuels made from crops are likely to have greater impacts than biofuels made from waste products. EPA evaluated the range of potential impacts from the RFS program in the May 19 BE, in which corn, soybean, and canola are each evaluated for their potential expansion due to the requirements of the RFS program. With the ESA consultation, the evaluation of potential impacts that such land use changes may have on critical habitats and water quality are factors that have been taken into consideration in finalizing this action.

Comment:

A commenter suggested that EPA's consideration of ecosystems was insufficient because EPA "conceded that it could not perform a full assessment of the proposed volumes' impacts on ecosystems."

Response:

EPA acknowledges that in previous rules and the proposal for this action, EPA performed a limited analysis of ecosystems. However, as referenced earlier, the May 19 BE submitted to the U.S. Fish and Wildlife Service and the National Marine Fisheries Service (together, the "Services") address this statutory factor. The May 19 BE contains extensive analyses of the rule's volumes and how they could potentially affect land conversion (including ecosystems and critical habitats) in the United States based on the best scientific and commercial data available, as directed by ESA section 7(a). Additional information on EPA's evaluation of ecosystems can be found in RIA Chapter 4.3 and additionally in the May 19 BE, available in the docket for this action.

9.2.5 Endangered Species Act

Comment:

A commenter suggested that EPA did not consider impacts on endangered species when considering the impact of renewable fuels on the environment because the BE was not complete at the time of the proposal. The commenter also stated that EPA did not provide an opportunity for the public to meaningfully comment on the BE.

Response:

Under ESA implementing regulations, EPA is obligated to consult with the Services if EPA determines that its action "may affect" listed species or critical habitat. Neither the "may affect" determination nor the BE are subject to public notice or comment requirements under the CAA, ESA, or the ESA implementing regulations. While we have utilized some of the analysis underpinning our May 19 BE to support our assessment of several CAA statutory factors for this rule, including impacts on wildlife habitat, ecosystems, and water quality, those assessments are separate from our ESA obligations, and support our analysis of the statutory factors as required under CAA section 211(o)(2)(B)(i) independent from the May 19 BE and its assessment of how the action could affect listed species and critical habitat.

While the commenter is correct that such analysis, as it relates to the statutory factors related to impacts on the environment, was not available at the time of the proposed rule, omitting such information from consideration would equally not be appropriate, as it is known relevant information that informs our analysis of the statutory factors and expands on our assessment of the factors provided at proposal. Such analysis is bolstered by our "no RFS baseline" assessment that was provided in the proposed rule, and utilizes SWAT modeling that was also referenced in the proposed rule. See RTC Sections 9.2.3 and 9.2.4 for further discussion on these topics.

Comment:

Several commenters suggested that EPA must complete ESA consultation prior to competition of the final rule. A commenter suggested it was inappropriate for EPA to finalize volumes that significantly exceed the 2017 standards, the last annual rulemaking for which "the D.C. Circuit did not hold to be deficient with respect to the ESA."

Response:

EPA submitted its initial biological evaluation to the Services on January 30, 2023. Then, following continued consultation—including regular meetings and telephone and email communications between EPA and the Services—EPA submitted its May 19, 2023 biological evaluation to the Services on May 20, 2023, and, in response to an additional question from NMFS, emailed to the Services an addendum on May 31, 2023. EPA concluded that that the Set Rule is not likely to adversely affect listed species and critical habitat. The Services have indicated that the May 19 BE is sufficient and that they intend to proceed with informal consultation. EPA has prepared an ESA section 7(d) determination memorandum that discusses our decision to finalize this action before the informal consultation process is complete, which is also available in the docket for this action.

Comment:

A commenter suggested that EPA has an obligation under ESA section 7(a)(1) to develop a program to proactively conserve listed species.

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.

Nevertheless, we note that CAA section 211(*o*)(2)(B)(ii)(I) requires that EPA consider the impact of the production and use of renewable fuels on wildlife habitat in determining the volumes for years after those specified in the statute. This statutory term, "wildlife habitat," would properly include endangered and threatened species and their habitats, as well as designated critical habitat.[126] We maintain that the analysis under CAA section 211(*o*)(2)(B)(ii)(I) is separate from our ESA consultation requirements, as discussed in RTC Section 9.2.4. However, we have properly considered the conservation of endangered species within the context of the analysis under CAA section 211(*o*)(2)(B)(ii)(I), and EPA retains the ability to waive applicable volumes on the basis of severe environmental harm, if so warranted.

[126] See, e.g., 87 FR 80582, 80622 (December 20, 2022) (considering effect of increases in cellulosic biofuel volumes on ecosystems and wildlife habitat).

9.3 Comparison of Costs and Benefits

Comment:

A number of commenters stated that the proposed standards are too high because the monetized costs estimates in the analysis of the proposed standards were larger than the monetized energy security benefits estimates.

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 of the statutory factors, nor does the statute indicate how to weigh the factors. As discussed in Preamble Section IV.D, EPA considered all of the assessed impacts and found the final volumes to be appropriate.

10. Biogas Regulatory Reform

10.1 General Comments on Biogas Regulatory Reform

Comment:

One commenter supported the proposed biogas regulatory reform provisions.

Response:

We thank the commenter for their support.

Comment:

Multiple commenters stated that biogas regulatory reform, or specific provisions within biogas regulatory reform, is not necessary. Multiple commenters stated that the proposed biogas regulatory reform provisions were unnecessary because EPA has not shared any instance of finding fraud in the RFS program. Commenters argued that the proposed biogas regulatory reform are substantial, potentially impacting the entire industry, and were believed to be largely unnecessary. One commenter stated that biogas regulatory reform is not necessary to allow for RNG as a biointermediate.

Response:

The commenters did not clearly explain how a lack of EPA sharing information about fraud would indicate that there is a low likelihood of fraud, particularly in expanding biogas use as a biointermediate. The lack of fraud being reported at present under the previous biogas provisions is not necessarily indicative of the lack of fraud occurring. It simply means that it has not been reported. By virtue of the construct of the previous biogas provisions and the difficulty in providing proper oversight, EPA is already concerned over the presence of fraud – even before the program is expanded.

The commenters conflated a purported lack of information about fraud to mean that the risk of fraud is low. This is not necessarily true; additionally, we disagree there is a lack of information about fraud. Specifically, the high QAP participation indicates that the fraud risk may be high. Cellulosic RINs, of which almost all involve biogas, have the highest percentage verified by an QAP provider.[127] The QAP program and verified RINs provide additional assurance to obligated parties that RINs are valid and helps with affirmative defense in case they are invalid. Obligated parties often pay a premium for verified RINs. If obligated parties believed the risk for fraud is low, we would anticipate that more of them would be willing to buy unverified RINs to save money when complying with RFS. The high participation in QAP for cellulosic RINs indicates to us that there may be a lack of trust among obligated parties on the validity of cellulosic RINs.

[127] For 2023, almost 100% of D3 RINs are verified under the RFS QAP, while less than 10% of D4, D5, and D6 RINs are verified. See https://www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard.

This information indicates that the risk of fraud for cellulosic RINs might be higher than for other fuels.

Furthermore, the commenters fail to address the fact that we are now allowing biogas and RNG for uses other than renewable CNG/LNG, which increases biogas program complexity and the potential for fraudulent and invalid RINs. We discussed this concern in the NPRM,[128] including why we believe the biogas regulatory reform we are finalizing in this action will provide the structure and transparency that are necessary to manage this complex system. We also discuss the need for these regulatory changes at length in Preamble Section IX.A.4.

Comment:

Multiple commenters suggested that the proposed biogas regulatory reform provisions would be burdensome on parties. One commenter stated that the rules are overly prescriptive and undermine previous relationships.

One commenter suggested that the proposed biogas regulatory reform provisions seemed unnecessarily burdensome. The commenter noted that EPA is already proposing such significant changes to the program that keeping certain existing procedures in place increases the likelihood of compliance and will be far less onerous on RFS participants and EPA staff. The commenter cited as an example the proposal that RIN separation occurring at the end of the value chain would require more RIN transactions and RINs changing hands than the previous biogas provisions before ultimately being sold to the end user (leading to more room for error). The commenter also noted that proposed changes such as the RNG producer being the RIN Generator allows proper gate keeping of multiple pathways stemming from one facility, and they believed a change like this would reduce transactions and workflows.

Multiple commenters said that some aspects of the proposed reform would affect biogas facilities owned and operated by municipalities (such as municipal landfills, municipal CNG/LNG dispensers, wastewater treatment plants, and municipal bus fleets) and that these smaller entities may be unable to afford the additional cost associated with dedicating resources to participate in the RFS program. Multiple commenters believed that participation by these smaller entities is essential for scaling the supply and use of biogas.

Response:

The commenters did not provide alternative approaches or programs to address the oversight and double-counting concerns around use of biogas to produce multiple types of biogas-derived renewable fuels, as discussed in the NPRM and Preamble Section IX.A.4.[129] Given that we still have concerns about proper oversight and double counting, we are finalizing biogas regulatory reform, including having the RNG producer generate and assign the RIN[130] and the party that

[128] 87 FR 80692-80693.
[129] 87 FR 80693.
[130] We discuss in detail why we selected the RNG producer to generate and assign RINs for RNG in Preamble Section IX.C and in Section 10.3.

demonstrates that the RNG was used as transportation fuel separate the RIN.[131] Nevertheless, we have made a number of changes from the proposal, discussed in Preamble Section IX and below, which will reduce the burden on regulated parties and, as discussed in Preamble Section IX.F, allow for more implementation time. This additional implementation time we believe will allow adequate time for parties to come into compliance.

With respect to concerns about small parties, the commenter did not explain how current flexibilities, such as having a third party submit reports on behalf of the registered party, are not sufficient to reduce the burden on these parties. As discussed in Preamble Section IX.C, we believe these parties will be able to participate in the program.

Comment:

Multiple commenters noted that biogas regulatory reform would require a significant amount of effort on industry's party to renegotiate contracts. One commenter noted that the proposed reforms would only provide stakeholders six months to renegotiate contracts that took several years to develop and cover biogas transfers well past the proposed deadline.

One commenter suggested that the proposed biogas regulatory reform changes will penalize the current participants in the biogas and RNG value chain who have developed compliance strategies and business arrangements that have resulted in the generation of the vast majority of D3 cellulosic biofuel RINs over the history of the RFS. The commenter notes that these program participants would need to change their business models and commercial agreements to meet the requirements of the proposed eRIN program. The commenter recommends that EPA bifurcate the biogas regulatory reform provisions from the volumes and not implement them as part of this rulemaking.

Response:

As discussed above, we feel compelled to finalize the biogas regulatory reform provisions at this time given their importance to providing appropriate compliance and enforcement oversight of the program and our allowance of expanded use of biogas and RNG for fuels other than renewable CNG/LNG. While we are finalizing biogas regulatory reform with the other portions of the rule, as we note in Preamble Section II, the biogas regulatory reform provisions are severable from the other portions of the rule.

As discussed in RTC Section 10.5 and Preamble Section IX.F, we are adjusting the timeline to allow both new and existing registrants additional time to, among other things, renegotiate contracts as suggested by the commenters. This additional time will provide adequate time for parties with existing contracts to renegotiate their contracts and come into compliance with the biogas regulatory reform provisions. We believe that the delayed implementation date for the biogas regulatory reform provisions addresses the commenter's concerns.

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[131] We discuss in detail our approach to RIN separation in Preamble Section IX.D and in Section 10.4.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter suggested that EPA's proposed biogas regulatory reforms could create disincentives to produce RNG and decarbonize the transportation sector. The commenter also suggested that the proposed new reporting and measurement requirements and other restrictions would hinder implementation and run counter to the RFS program goals.

Response:

The commenter does not provide any analysis or other support to show how these regulatory reforms may impact growth of renewable fuels. The commenter also does not explain which of the various proposed regulatory reform provisions would most likely to impact participation in the program. The commenter similarly does not clarify what specific provision in the proposed reporting and measurement requirements would hinder implementation. As discussed in Preamble Section IX.A, the biogas regulatory reform provisions are necessary to help ensure that biogas-derived renewable fuels are produced from renewable biomass and used as transportation fuel consistent with CAA and EPA regulatory requirements. We also discuss how the biogas regulatory reforms are needed to allow for the use of biogas as a biointermediate and RNG used as a feedstock to provide more opportunities for biogas-derived renewable fuels consistent with the broader goals of the RFS program. Finally, we note that some of the biogas regulatory reform provisions are intended to streamline participation in the program, making it less burdensome in the long term.

As discussed in Preamble Section IX.F. we are providing both new and existing registrants more time to comply with the biogas regulatory reform provisions. This additional time will allow stakeholders more time to adjust to the new reporting and measurement requirements. Furthermore, as discussed in RTC Sections 10.8 and 10.11 and Preamble Sections IX.H and IX.I, we have clarified and adjusted the reporting and measurement requirements in response to commenter suggestions to reduce administrative burden while maintaining oversight.

Comment:

One commenter suggested that EPA should engage in more discussions with industry prior to finalizing the proposed biogas regulatory reform provisions.

Response:

In addition to soliciting and responding to comments on the proposed rulemaking, we have engaged in discussions on the biogas regulatory reform provisions with industry in stakeholder meetings conducted after publication of the NPRM.[132] Through this notice and comment process

[132] See the log of stakeholder meetings in the docket to this action.

we have adjusted the provisions in the final rule to be responsive to the concerns expressed by the stakeholders while still finalizing provisions that satisfy the needs of the program.

Comment:

One commenter did not agree with EPA's statement that allowing parties other than the RNG producer to generate RINs would allow for double counting and that the previous biogas provisions contractual network imposes such an impediment to EPA's oversight that EPA is unable to ensure that the RNG was not multiple counted before RIN was generated.

The commenter mentioned that RNG volumes are generally measured by third-party meters going into the pipeline and leaving the pipeline, so they do not see how an RNG producer could create contracts that would show volumes greater than the metered RNG that enter or leave the pipeline. The commenter also stated that information on biogas volume is also typically provided to the RNG producer, particularly at landfills, to ensure compliance with permits and/or state requirements. The commenter stated that these reasons lead them to believe EPA's concerns with respect to double counting are misplaced and unsupported, and that there is no need for substantial changes to how the program operates.

The commenter stated that EPA has not explained why restricting RIN generation and separation, all of the proposed regulatory requirements, or the proposed restrictions are necessary to ensure compliance with the RFS program. The commenter does not believe merely asserting that there could be fraud (with no real-world examples) is a sufficient reason to justify the proposed biogas regulatory reforms.

Response:

Under the previous biogas provisions, we already have concerns that all the gas entering the pipeline might not be biogas-derived, and that there is a potential for double counting of RINs because the documentation demonstrating that renewable CNG/LNG produced from the RNG was used as transportation fuel is relied upon by multiple parties. Since the previous biogas provisions are based on tracking contracts, it is very difficult for EPA to verify through the many and overlapping contracts whether such double-counting is occurring. Further, while permits provide information on maximum gas flow, they do not represent actual gas flow, and parties may attempt to generate RINs on maximum permitted figures instead of actual gas flows. The commenter does not explain how these concerns are misplaced or unsupported, and given this, we are finalizing biogas regulatory reform with some modifications as described below. As discussed in Preamble Section IX.A, the biogas regulatory reform provisions are necessary to help ensure that biogas-derived renewable fuels are produced from renewable biomass and used as transportation fuel consistent with CAA and EPA regulatory requirements. We also discuss how the biogas regulatory reforms are needed to allow for the use of biogas as a biointermediate and RNG used as a feedstock to provide more opportunities for biogas-derived renewable fuels consistent with the broader goals of the RFS program. Given that we are expanding opportunities for the use of biogas as a biointermediate and RNG as a feedstock to allow for biogas-derived renewable fuels other than renewable CNG/LNG, it is critical that we finalize a program that avoids double counting and ensures valid RIN generation.

Comment:

One commenter stated that the proposed 40 CFR 80.100(a)(2) appears unnecessary, is overly broad, and is inconsistent with EPA's explanation that it only seeks to regulate biogas producers, RNG producers, RNG RIN owners, and RNG RIN separators in the RNG production, distribution and use chain. The commenter further suggested that the phrase in the proposed regulations at 40 CFR 80.100(a)(2) that said "any person that engages in activities associated with" is overly broad. Alternatively, the commenter suggested that EPA should list the specific parties that are covered by 40 CFR part 80, subpart E.

Response:

We have clarified the applicability language at 40 CFR 80.100(a)(2) to note that the requirements under 40 CFR part 80, subpart E apply to "specified parties" that produce, distribute, and/or use biogas, RNG, and biogas-derived renewable fuels or generate RINs for RNG and biogas-derived renewable fuels. We believe that the applicability language included in 40 CFR 80.100(a)(2) is necessary to inform potentially regulated parties that produce, distribute, or use biogas, RNG, and biogas-derived renewable fuels or generate RINs for RNG and biogas-derived renewable fuels that they may have regulatory requirements under the new 40 CFR part 80, subpart E. This language is not intended to be a substitute for the specific regulatory requirements codified in 40 CFR part 80, subpart E. We believe this addresses the commenter's underlying concerns.

Comment:

One commenter stated that EPA's reference to other potentially applicable regulations in proposed 40 CFR 80.100(b) also is confusing, as the commenter claims that EPA does not regulate RNG elsewhere. The commenter highlighted as an example that EPA references requirements under Part 1090 throughout Subpart E, but that they were unable to find a portion of part 1090 that applied to biogas, RNG or renewable electricity under 40 CFR part 1090.

The commenter argued that although EPA incorporates certain provisions in 40 CFR part 1090 by reference in Subparts E and M, this does not make them regulated entities under 40 CFR parts 79 and 1090 The commenter noted that while they believe reliance on cross-references, particularly where the definitions used in the provisions being referenced are not consistent with the terms in the RFS regulations and the terminology used may not be applicable to renewable fuels, creates confusion, these provisions are also redundant. The commenter suggested that EPA could simply state that 40 CFR part 80, subparts E and M applies to producers of biogas, renewable electricity, and RNG that participate in the RFS program and that similar references in other proposed cross-references to 40 CFR part 1090 should be deleted.

Response:

We intended for the provisions at 40 CFR 80.100(b) to inform regulated parties of their potential regulatory requirements under different parts of EPA's fuels regulatory programs and how these other portions of the regulations relate to 40 CFR part 80, subpart E. The language at 40 CFR

80.100(b) is not intended to impose or serve as a substitute for the regulatory requirements in 40 CFR part 79, part 1090, and part 80, subpart M.

Regarding the cross-references to 40 CFR part 1090 in sections other than 40 CFR 80.100, we believe the references to 40 CFR part 1090 are clear even if the regulatory provisions in 40 CFR part 1090 use different terminology than in 40 CFR Part 80. Because the RFS program is part of EPA's larger fuels program, some of the regulatory provisions that apply to parties that participate in the RFS program are included in different parts of EPA's regulations. For example, RNG producers, biogas producers, and RNG RIN separators are required to undergo an annual attest engagement, and many of the provisions that apply to annual attest engagements are specified in 40 CFR 1090.1800 and 1805. The commenter appeared to understand that we intended the provisions in 40 CFR part 1090 to apply even with the difference in terms, and we hope to clarify this in this response. To clarify for the commenter, cross-references to 40 CFR part 1090 are intended to apply to the parties in the applicable sections in 40 CFR 80 even if the terms for the parties and facilities in 40 CFR part 1090 differ. It is the regulated party's responsibility to meet all applicable regulatory requirements.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

10.2 Biogas Under a Closed Distribution System

Comment:

One commenter noted that in the proposed registration provisions at 40 CFR 80.145(c)(5)(ii), EPA proposed to require a description of losses of heating content going from biogas to renewable CNG/LNG and an explanation of how such losses would be accounted for. The commenter claimed that EPA did not explain the need or basis for this proposed requirement as part of the registration, as required by the Clean Air Act nor did EPA explain how this requirement may impact ongoing operations where RIN generation generally must comply with the information in the registration. The commenter opposed this proposed registration requirement and suggested that at a minimum, EPA must make clear that this is for informational purposes only and not needed to be part of the attest engagement or QAP review.

Response:

In order to reduce the risk of double counting, we proposed this requirement to make sure that biogas closed distribution systems are operating consistent with the technology used to process the biogas. Without information describing the losses of heating content when biogas is converted to renewable CNG/LNG in a biogas closed distribution system, it would be difficult for QAP providers and EPA to know if the amount of treated biogas and renewable CNG/LNG produced qualifies under the program. We do not anticipate this information being used for attest engagements, though QAP plans may use this information to show that a facility is operating as expected. We discuss how registration requirements may impact ongoing operations when discussing implementation timing in Preamble Section IX.F and Section 10.5.

Comment:

One commenter stated that the proposed regulations at 40 CFR 80.142(b) appeared to require renewable CNG/LNG producers to generate RINs for renewable CNG/LNG from a biogas closed distribution system instead of the biogas closed distribution system RIN generator. The commenter noted that under the proposed regulations a biogas closed distribution system RIN generator must separate RINs if the party demonstrates that the renewable CNG/LNG was used as transportation fuel. The commenter suggested that EPA should allow flexibility in determining who can generate and separate the RINs in a biogas closed distribution system consistent with EPA's stated intent and it should clarify that any party in the biogas closed distribution system can generate and separate the RIN, so long as the required documents to establish use as a transportation fuel are obtained.

Response:

As noted in Preamble Section IX.B, we did not intend to modify the flexibility that any party within the biogas closed distribution system could generate the RIN. We also did not propose to change the RIN separation provisions that applied to renewable CNG/LNG used via a biogas closed distribution system. Under biogas regulatory reform, any party within the biogas closed distribution system may generate the RIN and that party must separate the RINs at the same time because the RIN will be generated after the party has demonstrated that the renewable CNG/LNG has been used as transportation fuel. This is identical to how this works under the existing biogas provisions at 40 CFR 80.1426(f)(10)(ii). We have clarified in 40 CFR 80.130(b)[133] that the biogas closed distribution system RIN generator is the party that generates and separates the RINs for renewable CNG/LNG in a biogas closed distribution system consistent with the commenter's suggestion.

Comment:

One commenter asked for clarification as to whether an RNG producer can also participate in the CNG/LNG market through a biogas closed distribution system.

Response:

We did not propose and are not finalizing a restriction on an RNG producer's (i.e., a company that meets the definition of RNG producer) ability to also serve as a biogas closed distribution system RIN generator. However, the limitations placed on biogas use in the regulations at 40 CFR 80.105(k) specify that a biogas production facility cannot supply biogas both for use in a biogas closed distribution system and in the production of RNG. Therefore, if an RNG producer also participates in the renewable CNG/LNG market through a closed distribution system, due to this limitation, it would have to segregate biogas from different biogas production facilities throughout the whole process or have separate facilities for RNG and for renewable CNG/LNG through a biogas closed distribution process. As discussed in Preamble Section IX.O, the biogas single use limitation is necessary to avoid double counting and ensure that EPA has the ability to oversee the program.

Comment:

One comment noted that although the proposed regulations at 80.142(b) refers to complying with 40 CFR 80.1426 with respect to RIN generation EPA does not explain how RINs are to be calculated as it does for RNG to CNG/LNG and how that might be different than the formulas provided for RNG in proposed regulations at 40 CFR 80.120(j). The commenter suggested that EPA should apply the same formula parties have used to date or provide an explanation as to the differences.

Response:

We have updated the language in the regulatory text to specify 40 CFR part 80 instead of specifically 40 CFR 80.1426, since we moved some provisions from the latter to subpart E. This should ensure that all applicable equations are clearly identified, including those describing renewable CNG/LNG in a biogas closed distribution system. To help clarify how the specific regulatory provisions for biogas, treated biogas, and renewable CNG/LNG in a biogas closed distribution system fit together, the following steps are listed below:

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[133] This appeared in the proposal in 40 CFR 80.142(b).

1. The batch pathway information (D-code, verification status, etc.) for the biogas used in the biogas closed distribution system should be calculated according to the biogas batch information specified in 40 CFR 80.105(j)(3).
2. Any losses from the point that the biogas is produced to the point that the biogas is ultimately used in the form of renewable CNG/LNG as transportation fuel need to be accounted for proportionally using the regulations at 40 CFR 80.110(j)(4), such that the total volume from each batch pathway is equivalent to the total volume of treated biogas that is dispensed as renewable CNG/LNG.
3. The volumes are converted to RINs using the applicable paragraph within 40 CFR 80.1426(f)(3).

Comment:

One commenter expressed confusion as to the wording in proposed 40 CFR 80.1426(f)(12)(i)(C) because the term "commercial distribution system" is not defined. The commenter asked how EPA distinguishes this from a natural gas commercial pipeline system to which biogas is not typically injected and noted that this term is used elsewhere in the regulations. The commenter also noted that in the market, RNG is considered pipeline quality, not biogas.

Response:

We recognize the commenter's confusion that using the term "commercial distribution system" instead of our intended "biogas closed distribution system" as appeared in the proposed regulations at 40 CFR 80.1426(f)(12)(i)(C). We intended the regulations to say, "biogas closed distribution system" and have clarified this clause by specifying that the system is a "biogas closed distribution system" in 40 CFR 80.1426(f)(12)(i)(C).

10.3 RNG Producer as the RIN Generator

Comment:

One commenter supports the RNG producer as the RIN generator.

Response:

We thank the commenter for their support.

Comment:

One commenter suggested EPA has not fully considered the administrative effects on industry of specifying a RIN generator, which the commenter suggests is efficient for every party involved. The commenter suggested that fundamentally reconstructing that process will result in confusion during adjustment and rigorous, time-consuming contract amendments throughout the industry and questioned EPA's reasoning for the proposal.

Response:

As described in Preamble Section IX.A.4, the biogas regulatory reform provisions are needed to support the broad goals of the RFS program while ensuring that biogas, RNG, and biogas-derived renewable fuels are produced consistent with CAA and EPA regulatory requirements.

In the NPRM preamble, we recognized that RIN generators and other parties covered under a registration under the existing biogas provisions would have to modify their contracts and adjust their facility's registration to come into compliance with the new biogas regulatory reform provisions. We also prepared a proposed information collection request (ICR) for the NPRM where we thoroughly considered the administrative burden on parties subject to the proposed biogas regulatory reform provisions. We note that we received no public comments on the proposed ICR and the commenter failed to highlight any deficiency in our analysis of the potential administrative burden associated with the biogas regulatory reform provisions. We are including a final ICR with this action that reflects the final biogas regulatory reform provisions.

However, as discussed in Preamble Section IX.F, we recognize that existing registrants may need more time to adjust contracts, modify facilities, and update EPA registration information. As such, we are delaying implementation of the biogas regulatory reform provisions for existing registrants until January 1, 2025. This additional year should provide existing registrants enough time to comply with the biogas regulatory reform provision and help ameliorate the administrative burden associated with the new provisions.

Comment:

One commenter requested that EPA provide a similar provision like that for OEM RIN generators to allow for the generation of RINs prior to upstream are registered

Response:

We do not believe it is necessary to provide a flexibility for RNG producers to generate RINs prior to the registration of upstream parties (i.e., biogas producers) because we are providing adequate time for biogas producers and RNG producers to register. As discussed in Preamble Section IX.F, we are delaying biogas regulatory reform implementation for parties covered by an existing biogas registration until January 1, 2025. This delayed implementation will provide an additional year for biogas producers covered by an existing biogas registration to prepare and submit registration submissions, which we believe is more than adequate. To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

Multiple commenters suggested that EPA's proposal to limit RIN generation to RNG producers would impact many RNG producers who do not have the expertise or personnel to bear the responsibility. The commenter suggested that EPA needs to consider that many small-to-medium scale producers cannot or will not undertake the RIN generation cost, liability, and compliance obligation associated with generating RINS. Therefore, the commenter recommended EPA continue to allow any party to be the RIN generator.

One commenter contended that, as proposed, limiting the RIN generator to one party will restrict (and in some instances eliminate) the development of RNG projects. The commenter suggested that small agricultural/livestock waste providers and municipally owned wastewater treatment plants and landfills lack the expertise and resources to meet the administrative requirements to serve as the RIN generator. The commenter further suggested that forcing that regulatory burden on these parties will decrease and, in some cases, eliminate their interest in developing their RNG assets.

Response:

We conducted an analysis of the parties registered to generate RINs for biogas under the previous biogas regulations and determined that over 50% of the RIN generators would meet the definition of RNG producer under the biogas regulatory reform provisions.[134] Based on this analysis, we believe that RNG producers are capable of bearing the responsibility of generating RINs because many of them are already doing so.

RNG production facilities cost millions of dollars to develop and often involve dealing with local, state, and federal (including other EPA) regulatory requirements to permit, construct, and operate such facilities. The commenters provide no explanation how these parties are capable of meeting the myriad applicable regulatory requirements that apply to these parties but are unable to meet the RFS requirements for RIN generation. Furthermore, as discussed in Preamble Section IX, we expect that these parties may contract with third parties to help them comply with EPA regulatory requirements, an approach that many small-to-medium sized RIN generators already employ to participate in the RFS program. At the same time, it is worth highlighting that there is no requirement that these parties participate in the RFS program and generate RINs. The

[134] See "Analysis of engineering reviews for identifying biogas RIN generators" in the docket to this action.

generation of RINs under the RFS program provides them with an additional revenue stream to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

While we acknowledge that parties covered by a registration under the previous biogas provisions would have to incur some administrative burden to come into compliance with the biogas regulatory reform provisions, we expect that the biogas regulatory reform provisions will ultimately reduce the burden associated with participating in the RFS program. We have streamlined the registration, reporting, and recordkeeping requirements to minimize the administrative burden associated with RNG RIN generation especially when compared to the previous existing regulations and have extended the implementation date until January 1, 2025. As described in Preamble Section IX, we have minimized complexity in the program by removing the onerous contractual requirements required under the previous biogas provisions. Also, as discussed in Preamble Section IX, we intend to make enhancements to EMTS that should improve user experience and reduce administrative burden associated with reporting requirements. We believe the simplification of the biogas to renewable CNG/LNG program will make it more likely that RNG projects could participate in the program

We have also codified provisions that clearly specify when RNG producers are liable for violations under the RFS program as well as when RNG producers can establish an affirmative defense. These provisions will provide regulatory certainty for RNG producers, and the commenters fail to explain how these provisions are inadequate or how they will directly cause parties to not participate in the program.

10.4 Assignment, Separation, Retirement, and Expiration of RNG RINs

10.4.1 RNG RIN Assignment/Separation

Comment:

Multiple commenters requested that EPA make clear that its reference to changing the "book and claim" process for RNG is to the paperwork requirements, not the ability of downstream parties to use gas from the commercial pipeline system to establish use of the RNG for transportation fuel to support RIN generation.

Response:

The biogas regulatory reform does not fundamentally change the way that the biogas to renewable CNG/LNG pathway operates under the RFS program. Rather, it changes how biogas, RNG, and renewable CNG/LNG are tracked as they move through the natural gas commercial pipeline system. Major changes to the "book and claim" process includes sunsetting regulatory procedures where RNG producers had to submit contractual records documenting each party in the biogas distribution/generation chain as part of the registration process and allowing any party in that chain to generate and separate the RNG RIN. Under biogas regulatory reform, RNG RIN separators will be able to separate RINs attached to RNG injected into the natural gas commercial pipeline system after demonstrating the RNG was used as transportation fuel in the form of renewable CNG/LNG.

Comment:

Multiple commenters opposed the proposed RIN separation requirements for RNG. One commenter expressed concern over the increased administrative burden on small to medium-sized entities as well as potential disruption to current business practices. Other commenters anticipated making significant changes to existing contracts to meet the new regulatory requirements. Finally, one commenter expressed general disapproval of the RNG RIN separation requirements while expressing its support for the existing regulatory model. One commenter said that requiring the dispenser to separate RINs without exception is a marked departure from current practice without any demonstrable benefit.

Response:

These comments are expressing themes already discussed earlier in this document. We acknowledge that the biogas regulatory reform provisions will create some changes to processes and procedures. However, as discussed in detail in Preamble Section IX.A.3, finalizing these changes in the regulations is necessary to improve our ability to register RNG producers, oversee compliance with RNG RIN assignment and separation and allow for new options such as designating biogas as a biointermediate. Based on other comments received, EPA has delayed the implementation date by one year to January 1, 2025, and will work with industry during the transition period to actively minimize impacts on ongoing operations. This additional 12 months will provide industry adequate time to rework contracts to comport with the biogas regulatory reform provisions.

As described in detail in Preamble Section IX.D, this change creates the ability for the RNG RINs to be tracked electronically through EMTS, reduces opportunities for fraud and creates a foundation for new pathways such as biogas to be used as a biointermediate. Based on these benefits, we are finalizing this change as proposed.

Comment:

Some commenters suggested EPA consider additional alternatives and flexibility to the RNG RIN separation requirements. This includes allowing for obligated parties to continue separating RNG RINs or allowing delegation of RIN separation responsibilities to third parties. Another commenter proposed allowing parties to continue under the current regulatory structure if they participate in the QAP program.

Response:

Existing compliance flexibilities allow for third-party agents to submit compliance reports, including RIN separation transactions, on behalf of companies. These flexibilities remain. Additionally, the intent of the biogas regulatory reform is to put in place a system capable of tracking RINs from the RNG producer to the entity actually processing the RNG into transportation fuel. RIN separation is reported at the company level and obligated parties are domestic refiners or importers that typically have multiple facilities or import sites across the US. Allowing other entities such as obligated parties to separate the RNG RINs prior to use as transportation fuel would not support the overall intent of the reform. Because obligated parties may serve other roles in the biogas RIN generation/disposition chain (e.g., be the RNG producer or a RIN owner), allowing obligated parties to separate the RIN would result in the separation of the RIN for the RNG prior to demonstration that the RNG has been used as transportation fuel. Without the requirements that RINs remain assigned to volumes of RNG until it has been demonstrated to be used as transportation fuel there is a risk that the RNG RINs separated by obligated parties would not represent transportation fuel since RNG has many uses other than transportation fuel. For these reasons, we are finalizing as proposed the provisions related to RNG RIN separation.

Comment:

One commenter asks EPA to clarify the proposed regulations at 40 CFR 80.140(c)(2) to note that RINs may be generated for biogas-derived renewable fuels using RNG as a feedstock.

Response:

As noted in Preamble Section IX.L, we are finalizing provisions that will allow for renewable fuel producers to use RNG as a feedstock. Consistent with the commenter’s suggestion, we have added a regulatory provision at 40 CFR 80.125(b)(9) to clarify that renewable fuel producers may generate RINs for renewable fuels produced from RNG used as a feedstock as long as all applicable requirement under 40 CFR part 80 are met. To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter asked that 80.142(a)(2) say "All RIN transactions must be reported to EMTS as specified in §80.1452". The commenter noted that this would improve clarity.

Response:

We appreciate the commenter's concern about maximizing clarity. However, we are also balancing the need to minimize redundant text in the regulations. Based on experience with other fuels reporting programs, the text in 80.142(a)(2) provides enough detail and specific procedures will be provided through implementation and other compliance assistance tools.

Comment:

One commenter requested that obligated parties be able to separate RNG RINs like other fuels.

Response:

A discussed in Preamble Sections IX.A and IX.D, one intent of the biogas regulatory reform is to provide EPA and independent third-party reviewers improved ability to oversee compliance and be able to track the RINs generated for RNG through conversion to CNG/LNG. One of the key components of this reform is limiting RIN separation from actual RNG volumes to only parties who are converting the RNG into renewable CNG/LNG for use as transportation fuel. RNG RINs do not represent a finished transportation fuel, and therefore cannot be separated. Under the biogas regulatory reform provisions, only RINs associated with the finished transportation fuel (e.g., renewable CNG/LNG) can be separated.

We believe that limiting RIN separation to parties that create transportation fuel greatly improves our ability to oversee compliance because previously RINs were separated for other various reasons under 40 CFR 80.1429. Allowing RIN seperation by additional parties for additional purposes would undermine the purpose of biogas regulatory reform. As noted above, allowing obligated parties to separate RINs without demonstrating that the RNG had been used as transportation fuel would undermine the ability to track the movement of the RNG via the natural gas commercial distribution system. While this new limitation does limit some ability of obligated parties to separate RINs that they own, they are still able to separate RINs from other fuel types (ethanol, biodiesel). We do not expect that this change will significantly impact the ability of obligated parties to comply with the RFS. For these reasons, we are finalizing as proposed that obligated parties may not separate RNG RINs.

Comment:

One commenter supports the decision to designate the entity withdrawing RNG from the commercial pipeline system as the RIN separator

Response:

We appreciate the commenter's support and are finalizing this requirement.

Comment:

One commenter recommended that EPA ensure that third-party agents would have the ability to associate with the regulated parties' registration accounts and generate or separate RINs on their behalf. EMTS currently allows staff outside a company to associate with an account; this ability should remain and include full functionality for tasks like RIN generation and separation. EMTS can track all associations and maintain final approvals and signoff by the regulated party, ensuring proper oversight of the required information.

Response:

Third-party agents can associate to the registration accounts under other regulated parties, such as RNG producers. Based on the level of approval granted by the regulated party, third-party agents have the capability to directly submit registration updates, EMTS transactions and other compliance reports. We appreciate the commenter's support of the current functionality and procedures within the IT systems used to implement the RFS program, and we are not intending to limit the functionality related to third-party agents as part of this action. We are always looking to continuously improve these tools and look forward to receiving additional feedback from system users as we implement the biogas regulatory reform provisions. While we are maintaining existing functionality within our IT systems, we are not intending to add functionality to our IT systems that would be inconsistent with our intent to have RNG producers generate RINs and RNG RIN separators separate RINs. We discuss in detail why RNG producers are most appropriate to generate RINs and why RNG RIN separators are most appropriate to separate the RINs in Section IX.C and IX.D, respectively.

Comment:

One commenter stated that EPA should not require the generation of RINs on all RNG produced. The commenter states that this is inconsistent with how EPA treats other biofuels. The commenter suggested that EPA should allow RNG producers to retire assigned RINs to allow greater flexibility for producers or agents to take RNG to other markets. The commenter stated that EPA must clarify whether all RNG must generate RINs, regardless of whether there is an intention to participate in the RFS program. The commenter stated the following reasoning: "EPA also references RINs for RNG used as process heat, which arguably does not fall under EPA's definition. It is unclear if this is simply vague language or EPA intends to require all RNG to generate RINs. EPA should clarify that PTDs are only required for purposes of confirming compliance with the RFS and not require PTDs for biogas and RNG not sold for purposes of producing a renewable fuel under the program."

Response:

We are finalizing modifications to the definitions for biogas, RNG, and treated biogas at 40 CFR 80.2 to require that the product be produced under an EPA-approved pathway. Gas that is not produced under an approved pathway would not be subject to RFS requirements, and as such, would be ineligible for RIN generation. For example, gas produced from anaerobic digestion of cow manure for which the biogas producer has not registered would not be biogas under the definitions. If the producer, however, were to register, associate with an RNG producer, and meet all the other regulatory requirements, the gas would be biogas. The same would be true for RNG and treated biogas. While we are requiring that all RNG generate RINs, we are defining RNG in such a way that excludes gas produced that is not registered in the program.

10.4.2 RNG RIN Retirement

Comment:

One commenter suggested that EPA also should clarify that the prohibition in 40 CFR 80.1426(c)(6) does not apply to RNG that has generated RINs.

Response:

We are finalizing language at 40 CFR 80.1426(c)(6) consistent with the commenter's suggestion to clarify that parties that use RNG as a feedstock can use the biogas regulatory reform provisions and do not need to submit a pathway petition under 40 CFR 80.1426(c)(6).

Comment:

One commenter requested clarification if RINs should be generated and subsequently retired for RNG that is not designated for a use that would generate RINs.

Response:

As discussed in detail at Preamble Section X.E, we are finalizing as proposed changes that will allow RIN generators flexibility to not generate RINs for RNG or renewable fuel. The commenter describes a scenario where the RNG is not designated for use under the RFS program and RINs should not be generated under this scenario since the fuel does not meet the requirements in 80.1426(a)(1).

Comment:

One commenter stated that EPA provides no explanation for adding 'leakage' as a reason that RINs must be retired under 40 CFR 80.1434. The commenter stated that for RNG, volumes measured to generate RINs would not include any potential leakage, and that EPA must not make this change unless it undergoes proper notice and comment and explains this provision.

Response:

We disagree with the implication that retiring RINs for leakage of renewable fuel was not previously required. Treatment of RINs that do not represent renewable fuel is explained in the existing RFS regulations under "Treatment of invalid RINs" (80.1431), "Reported spillage or disposal of renewable fuel" (80.1432) and "RIN retirement" (80.1434). Retiring RINs for volumes of renewable fuel not used as transportation fuel is not a new requirement and has been in place since the start of the RFS program. For example, other renewable fuel producers such as ethanol or biodiesel producers have been retiring RINs for reported spills since 2010 as shown on EPA's public RFS data page. Additionally, downstream entities such as an RNG RIN separator can only separate RINs from the volume of renewable CNG/LNG used as transportation fuel (see 40 CFR 80.140(d)). We only added the term "leakage" under 40 CFR

80.1434 to clarify the terminology as it pertains to RNG for use when retiring RINs in the EMTS system.

10.5 Implementation Dates

Comment:

Multiple commenters suggested that EPA should allow biogas producers to continue to produce qualifying biogas until EPA has accepted their applications, as it is completely unclear how EPA intends to adequately and expeditiously process applications that would allow current biogas producers to come into regulatory compliance in a timely fashion. EPA proposes to give itself until April 30, 2024, to accept as complete applications from biogas producers and renewable electricity generators that intend to participate in the new eRINs program. However, EPA makes no similar accommodations for biogas producers whose product is intended to be consumed as renewable CNG/LNG.

Response:

As discussed in Preamble Section IX.F, we are delaying implementation of the biogas regulatory reform provisions for existing registrants until January 1, 2025. This additional time will provide biogas producers whose product is intended to be consumed as renewable CNG/LNG 15 months to prepare, submit, and have accepted registration submissions to comport with the new regulatory requirements.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter noted that EPA will be operating under a heavy administrative burden as EPA is implementing both the electricity pathway as well as biogas reform simultaneously. As a result, they expressed concern that EPA did not provide sufficient time for both the industry as well as EPA to transition to this new paradigm.

Response:

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Further, as discussed in Preamble Section IX.F, we are delaying implementation of the biogas regulatory reform provisions for existing registrants until January 1, 2025. We believe both EPA and industry will have sufficient time to implement and transition to the new biogas regulatory reform provisions.

Comment:

Multiple commenters suggested that EPA defer implementation of any biogas regulatory reforms until January 1, 2025, to allow stakeholders more time to comply with the new biogas regulatory reform provisions. Multiple commenters noted that EPA is proposing an implementation date of

January 1, 2024, for the biogas regulatory reforms and that deadline would not be enough time to transition. Multiple commenters noted that more time was needed for RNG producers to rework long-term contracts for both RNG sales and RIN sales, biogas and RNG producers would need more time to ensure they have the proper metering equipment, and landfills will have to ensure EPA' s requirements are consistent with other federal and state regulations of methane emissions and waste management. Multiple commenters further noted that since existing operations are targeted for CNG/LNG and may require more time to come into compliance, EPA could phase in the requirements to start with only facilities that seek to use biogas for renewable electricity or the RNG for renewable electricity or as a feedstock for another fuel to be subject to these requirements by January 1, 2024, with existing facilities having until January 1, 2025.

One commenter also suggested that EPA could also require any new RNG facility that starts operations after January 1, 2024, to be subject to these requirements.

Response:

As discussed in Preamble IX.F, we are delaying implementation for existing registrants until January 1, 2025, as suggested by the commenters. This additional time will provide parties covered by an existing registration time to rework contracts, adhere to the new regulatory requirements, and for EPA to accept and review updated registration information in a timely manner. We are also providing new registrants an additional 6 months (i.e., until July 1, 2024) to begin complying with the biogas regulatory reform provisions. This additional 6 months will allow both affected stakeholders and EPA more time to prepare for implementing the new biogas regulatory reform provisions.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

Multiple commenters suggested that EPA should provide sufficient time for all participants to adjust their contracts and prepare for the new biogas regulatory reform requirements and in addition provide provisions for an adequate transition, including allowing storage prior to registration approval. One commenter urged EPA to defer biogas regulatory reform to a later date or separate rulemaking to allow stakeholders enough time to implement the proposed reforms.

Response:

As discussed in Preamble IX.F, we are delaying implementation for existing registrants until January 1, 2025, which will provide sufficient time for all participants to adjust their contracts and comply with the biogas regulatory reform requirements as suggested by the commenters. While we are not separating out the biogas regulatory reform provisions from this action, the biogas regulatory provisions are severable from the other portions of the final rule as discussed in Preamble Section II.G.

We discuss the provisions related to the offsite storage of biogas/RNG prior to registration in Preamble Section IX.N and Section 10.15 below.

Comment:

One commenter stated that EPA identifies no upcoming pathway or fuel that would allow RNG to be used as a feedstock (if there was, it should be included in the volume projection), so they do not believe these provisions must start by January 1, 2024.

Response:

As noted in the NPRM and in Preamble Section IX, we did not propose nor are we finalizing new pathways in this action. We have received several pathway petitions requesting the use of biogas as a biointermediate or RNG as a feedstock, and multiple commenters expressed in the 2020-2022 RVO rule that EPA should include biogas as a biointermediate as part of the biointermediates provisions. Because of the uncertainty of when these new pathway submissions would be approved and facilities that would use them would be built, we have not included them in volume projections for this rule. As noted in Preamble Section IX, the biogas regulatory reform provisions are necessary to allow biogas to be used as a biointermediate or RNG to be used as a feedstock, and now that we have finalized these provisions, we can consider those pathway submissions. The delayed implementation dates for new and existing registrants should allow EPA time to consider those pathways in a timely manner.

Comment:

One commenter mentioned the following changes that are needed for biogas regulatory reform that support delaying implementation:

- RNG producers have often entered into long-term contracts for both RNG sales and RIN sales. These would need to be re-negotiated to be consistent with the changes in the regulations.
- Biogas and RNG producers would need to ensure they have the proper metering equipment.
- Landfills will have to ensure EPA's requirements are consistent with other federal and state regulations of methane emissions and waste management.
- Where pipelines are generally regulated by FERC or state entities, RNG producers would need to ensure they can comply with both sets of requirements.

Response:

Although it is not clear how the biogas regulatory reform provisions would alter landfills' and pipelines' other federal and state regulatory obligations, as discussed in detail in Preamble Section IX.F, we are delaying implementation of the biogas regulatory reform provisions for new registrants to July 1, 2024, and for existing registrants until January 1, 2025, in part to allow for parties more time to comply with the new biogas regulatory requirements. This would include more time for affected stakeholders to rework contracts, install compliant meters, and ensure compliance with other local, state, and federal requirements.

Comment:

One commenter stated that the requirements that existing RNG producers and CNG/LNG RIN generators must meet to avoid updating their registrations are not feasible given the updated requirements. The commenter stated further that it is unclear what happens to existing registrant's registration and whether they can generate RINs in the meantime. The commenter recommends that these reforms be delayed until at least January 1, 2025.

The commenter also stated that EPA does not explain whether RINs could still be generated if the biogas producer is not yet registered.

Response:

As discussed in Preamble Section IX.F, we are allowing existing registrants to utilize the previous biogas provisions to generate RINs for renewable CNG/LNG under 40 CFR 80.1426(f)(10)(ii) or (11)(ii) through December 31, 2024. This implementation date will facilitate the generation of RINs covered by an existing.

We recognize that there may be multiple facilities that must submit updated registrations. One reason we are providing extra time for existing registrants to come into compliance is due to the time necessary for them to update their registrations.

RNG producers cannot generate RINs under subpart E unless they are using biogas produced from a biogas production facility that is registered under subpart E.

Comment:

One commenter noted that EPA proposed changes to the engineering review provisions and did not indicate how these proposed changes affect existing registrations or whether existing registrations would require updating. The commenter noted further that any changes to the registration process would require time for the third party to review and update their practices to comply with the new requirements, which EPA did not appear to take into account in assessing the appropriate implementation date.

Response:

As discussed in Preamble Section IX.F, we are delaying implementation of the biogas regulatory reform provisions for existing registrants to January 1, 2025. We are also requiring the submission of updated registration information by October 1, 2024 for parties covered by existing registrations. These extended deadlines will provide existing parties over 15 months to work with third-party engineers and prepare registration submissions for submittal to EPA. To further facilitate a smooth transition of existing registrants, we intend to conduct stakeholder outreach to continue to inform the regulated community about the new provisions under biogas regulatory reform.

Comment:

One commenter recommended that EPA phase in requirements such that new RNG facilities or existing RNG facilities that that seek to use the RNG as a feedstock for another fuel would be subject to subpart E by January 1, 2024, while other existing facilities would have until January 1, 2025.

Response:

As discussed in Preamble Section IX.F, we are delaying implementation of the biogas regulatory reform provisions for existing registrants until January 1, 2025. For new registrants, we are delaying implementation until July 1, 2024. This phased implementation is consistent with the commenters suggestion, and we believe will allow EPA and industry enough time to adjust to the new biogas regulatory reform provisions.

Comment:

One commenter requested EPA clarify that parties deemed registered under subpart E may be different parties than the RNG producer or the producer of renewable CNG/LNG in a closed distribution system. The commenter would like parties to be deemed registered so long as updated registrations are submitted to EPA by November 1, 2024 (or preferably January 1, 2025) and be eligible "to generate RINs until EPA approves the updated registration and except these "updates" from the requirements in proposed § 80.145(b)(4)."

Response:

As discussed in Preamble Section IX.F, we are delaying implementation of the biogas regulatory reform provisions for existing registrants until January 1, 2025. To facilitate this delayed implementation, we have modified the regulations at 40 CFR 80.100 to further clarify our intent to allow parties operating under an existing registration for the generation of RINs under 40 CFR 80.1426(f)(10)(ii) and (11)(ii) to continue to do so until January 1, 2025. The biogas regulatory reform provisions allow for RIN generators to generate RINs for renewable CNG/LNG produced by January 1, 2025, under the previous biogas provisions. Because of the October 1, 2024, deadline for submission of updated registration information for existing registrants, there may be a time where an RNG producer is registered to generate RINs under both the previous biogas provisions and the biogas regulatory reform provisions. If EPA accepts the RNG producer's updated registration information prior to January 1, 2025, the RNG producer may generate RINs under either registration so long as all applicable regulatory requirements are met and there is no double-counting. Only RNG producers can generate RINs on RNG produced on or after January 1, 2025.

10.6 Definitions

Comment:

Multiple commenters requested a broader definition of biogas.

Some commenters state that the definition of biogas, which excludes treatment to remove inert gases and impurities, should be changed to allow for removal of certain impurities (e.g., hydrogen sulfide and siloxanes) since the commenters state that for most facilities, biogas must be treated to remove impurities before use in an engine generator.

Some commenters recommended to define biogas as "any mixture of hydrocarbons and noncombustible gases in a gaseous state produced from renewable biomass"

Response:

We intended our definition to include biogas that undergoes minimal processing before it is used as a biointermediate or to produce biogas-derived renewable fuel. The purpose of this definition was to try to ensure that the product leaving a biogas production facility was measured by the biogas producer so that such measurement information could be used to ensure that RINs were validly generated consistent with CAA and EPA regulatory requirements. We realize we may have inadvertently excluded some volumes that remove hydrogen sulfide, siloxanes, and other components. We have reworded the definition to state that biogas must require the removal of additional components to be suitable for its designated use. We believe this provides flexibility to stakeholders while meeting the intent of the proposal and at the same time ensuring that biogas is appropriately measured at biogas production facilities.

For commenters asking for an even broader definition of biogas, we are concerned that this may include other processes for which we have not evaluated all the necessary requirements for incorporation into the program, such as gas from pyrolysis of woody biomass. The commenters also did not discuss the implications for defining biogas to include gases that are not produced through anerobic digestion. Given that the commenter did not fully explain the ramifications of the broader definition that they recommended, we are not broadening the definition of biogas to include gases that are not produced through anaerobic digestion.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

Multiple commenters stated that the biogas production facility definition is vague and may be overly broad. One commenter added "Under such a broad definition, we oppose the proposed limitations on the activities that EPA appears to indicate would be authorized if there is generation of RINs associated with that biogas facility." One commenter stated that where biogas is 'produced' and what it means for biogas to be 'under an approved pathway' are unclear. This commenter recommended the following definition: "Biogas production facility means any landfill, municipal wastewater treatment facility digester, agricultural digester, separated MSW digester, other waste digester, or other similar processing unit that produces biogas used in the production of a biogas-derived renewable fuel."

Response:

The commenters do not provide an example of how the proposed broad definition of biogas production facility would have negative consequences to stakeholders or to the program. We also did not find a limitation in the proposed 80.105(k) that would not allow RINs to be generated for a facility that is a biogas producer and also an RNG producer. Given this, it is unclear how changing the definition in this final rule would advance the goals of the program.

The definition of biogas production facility suggested by one commenter seeks to define the biogas production facility as a processing unit. Consistent with our long-standing practice under RFS, we think it is best for facilities in the program to meet the definition of facility in 80.2 because facilities can often have multiple units and vary significantly in their configuration (e.g., the type and number of processing units) depending on the feedstocks used and products made. We also have concerns that such a narrow definition of facility would significantly increase the administrative burden to EPA and industry because it could significantly increase the number of registered biogas production facilities, periodic reports from such facilities, and metering points for each of those facilities. This would greatly complicate the program and, as stated in Preamble Section IX.A, one of the goals of biogas regulatory reform is to simplify the program. The commenter does not explain why the definition of facility should not apply to biogas production facilities.

Given the reasons above, we are not finalizing a change to the definition of biogas production facility. Though given the commenters' concerns, we would like to clarify in this response on what we mean by 'where biogas is produced' in the definition. 'Where biogas is produced' is the location where microbes process renewable biomass into methane. This includes landfills, municipal wastewater treatment facility digesters, agricultural digesters, separated MSW digesters, and other waste digesters.

To avoid any ambiguity around the definition in the regulations, we evaluated every instance of 'biogas production facility' and identified one use of the term that would be unclear if a facility was both a biogas production facility and a RNG production facility. We have updated this reference in 40 CFR 80.105(f)(1)(i) to clearly explain this situation.

Comment:

One commenter recommended changing the definition of 'biogas closed distribution system' to be broader to encompass where biogas is 'collected, cleaned, and/or and conditioned' instead of 'produced', change 'used as transportation fuel' to 'distributed for use as transportation fuel', and remove the exclusion that it does not include biogas placed on natural gas commercial pipeline system.

Response:

Below we discuss each of the recommended changes:

Describing where the biogas is produced, as defined in the previous response, provides more clarity at exact points where regulatory requirements are triggered than allowing a broad range of locations ('collected, cleaned and/or and conditioned') where regulatory requirements could be triggered. The latter approach would make it more difficult to oversee and enforce the program. For example, if a producer interprets the start point of a biogas closed distribution system to be where CO_2 is cleaned from the biogas, the biogas closed distribution system would not include the production of the biogas in a landfill or digester, making it more difficult for EPA and third-party auditors to ensure compliance. The commenter does not explain how the broad definition would not lead to more confusion at the point where regulatory requirements are triggered, and we are not incorporating this recommended change.

We recognize that including 'where biogas-derived renewable fuel is used as transportation fuel' in the 'biogas closed distribution system' definition may encompass more than we intended. The commenter recommended an earlier end point to the biogas closed distribution system, namely when the fuel is distributed for use as transported fuel. We are finalizing where biogas is used to produce biogas-derived renewable fuel as part of the definition of 'biogas closed distribution system.' This is a similar point to what the commenter recommended but has the benefit of aligning with language more commonly used in the existing regulations.

The commenter's recommended language would allow for a biogas closed distribution system to include injection of the gas into a natural gas commercial pipeline system. In the NPRM, we explain why a simpler regulatory framework is appropriate for when biogas-derived products (such as RNG or treated biogas) are not injected into a natural gas commercial pipeline system. We also explain that we used the term biogas closed distribution system to describe this situation. This commenter does not explain why we should allow biogas closed distribution systems to involve natural gas commercial pipeline systems or how to adjust the regulations to account for this change (e.g., make all biogas closed distribution systems subject to RNG producer requirements or eliminate RNG producer-specific requirements). Given that changing the definition as the commenter suggested would undermine the reasons for providing a simpler regulatory approach for biogas closed distribution systems and that such a change could affect other parts of the regulations, we are not allowing biogas closed distribution systems to include natural gas commercial pipeline systems.

Related to these recommendations by the commenter which sought to increase clarity in the definition, we also clarified the definition by only specifying the start and end of the system, by removing a middle point in the system, adding examples, and specifying raw biogas and treated biogas where appropriate.

Comment:

Several commenters said that the terms 'controls' and 'supervises' in some of the proposed definitions (e.g., biogas producer, and RNG producer) is vague and overly broad.

One commenter proposed the following definition: “Biogas producer means the owner or operator of any landfill, municipal wastewater treatment facility digester, agricultural digester, separated MSW digester, other waste digester or other similar processing unit that produces biogas used to produce renewable fuel [or the designated entity that registers on behalf of and has access to the required documentation for purposes of Subpart E and Subpart M].” This definition was based on the proposed REGS Rule, modified to include other operations. The commenter states that the language in brackets be added to other definitions which use the term ‘supervises’, and recommends it replace other definitions that contain ‘supervises’. Another commenter recommended adding the following parenthetical after ‘supervises’: “(i.e. any party or designated entity that registers on behalf of and has access to the required documentation for purposes of compliance with Subpart E and Subpart M).”

One commenter requested that EPA clarify that a person that “supervises” an RNG production facility can be an assigned third party. The commenter suggested that in its capacity as a supervisor, a third-party entity could generate RINS on behalf of the RNG Producer.

Response:

We chose the terms “controls” and “supervises” in the NPRM to be consistent with the language we have used to define facilities in our fuels regulations for over 40 years (i.e., in 40 CFR parts 80 and 1090). We believe consistency of language in the regulations is important and, given the commenters did not address potential issues with inconsistent language, we are finalizing this language as proposed. At the same time, we are clarifying for commenters, via this response, what is meant by these terms. Before discussing these terms specifically, we will first address the language two commenters recommended for the definition of biogas producer.

Both commenters recommend language that allows for designated entities to be the entities that are considered biogas producers. As discussed in the NPRM and Preamble Section IX, the goal of biogas regulatory reform was to ensure the program could be overseen and avoid double counting. A critical part of overseeing a program is being able to enforce on violations. Allowing a designated party to register as a biogas producer instead of the company that closely controls the assets or operations of the biogas production facilities would make it more difficult for the registered party to ensure compliance by actively overseeing the operation of the biogas production facility. The commenters do not explain how their proposed revision will ensure the same level of oversight than what was proposed. Given that we have concerns about ensuring the program can be overseen effectively, we are not finalizing an allowance for designated parties to register as biogas producers. As discussed in more detail in Preamble Section IX.C, we do note, however, that in our current regulations, we already allow registered companies to designate other entities within the system to submit forms on their behalf, and we expect biogas producers to utilize third parties to aide them in compliance as other parties regulated under the RFS have done so.

The term ‘supervises’ covers parties that manage the day-to-day operations of the facility and parties that are responsible for the product(s) produced from the facility. The term ‘controls’ covers entities that control physical access to the facility and have access to change the operations of the facility. These descriptions should help clarify what is meant in the definition that we are finalizing.

Comment:

One commenter asked for clarity on whether biogas used on-site to produce a renewable fuel, such as hydrogen, would still be considered ‘biogas used as a biointermediate’ since the definition does not exclude onsite generation.

Response:

We have added “at a separate facility from where the biogas is produced” to the definition of “biogas used as a biointermediate” to clarify that for biogas to be used as a biointermediate it must be transferred to another facility.

Biogas produced and used at the same facility to produce renewable fuel or a biointermediate other than renewable CNG/LNG would not be considered ‘biogas used as a biointermediate’ and would be subject to requirements in Subpart M for renewable fuel producers or biointermediate producers as appropriate.

Comment:

One commenter recommended adding a 7th item to biointermediate to clarify that RNG can be used to produce renewable fuel without being subject to the biointermediates requirements. The requested language is: “(7) Is not biogas that has been cleaned and conditioned to RNG, which can be used as a feedstock for production of renewable fuel as provided in Subpart E.”

Response:

We are clarifying in this response that biogas that has been cleaned and conditioned to RNG and is used as a feedstock for production of renewable fuel as provided in Subpart E is not a biointermediate. Unless there is a compelling reason, we typically do not define terms based on what they are not. Given the language used throughout the regulations is ‘RNG used as a feedstock’ and does not use the term ‘biointermediate’, we believe this language, in addition to this response, provides adequate clarity to the stakeholders.

Comment:

With regards to the definition of natural gas commercial pipeline system, one commenter noted EPA’s proposed regulations also refer to “natural gas commercial distribution system” and “commercial distribution system.” The commenter requested that EPA use consistent terms or define these terms.

Response:

We have updated the regulations to consistently use the term ‘natural gas commercial distribution system.’

Comment:

One commenter recommends modifying the definition of natural gas to only include renewable natural gas (RNG) in 40 CFR part 80, subpart E because, for purposes of 40 CFR part 80, subpart M, EPA should distinguish between geologic natural gas and RNG because RNG used as process heat can achieve lower GHG emissions.

Response:

The commenter did not provide a location in 40 CFR part 80, subpart M where the updated definition of natural gas would change the pathway by inadvertently classifying RNG with higher GHG emissions associated with natural gas. We looked at all references to natural gas in Subpart M and did not find any location where the proposed change by the commenter would change how a pathway is defined. Given that the regulations do not appear to be affected by limiting the definition of RNG as natural gas to Subpart E, we are not finalizing that the definition of natural gas including RNG only apply to Subpart E.

Comment:

One commenter recommends removing the pipeline specification requirement in the definition of renewable natural gas (RNG), stating that RNG does not need to be injected into a pipeline.

Response:

We proposed the biogas regulatory reform provisions to apply differently to biomethane placed on the natural gas commercial pipeline system and biomethane not placed on a commercial pipeline due to increased concerns about double-counting that could occur from the complexity inherent with the book-and-claim process involved with the natural gas commercial pipeline system. To differentiate these two regulatory structures, we defined biomethane used as transportation fuel without having been placed on the natural gas commercial pipeline system as treated biogas, and biomethane placed on the natural gas commercial pipeline system as RNG. If we were to remove the requirement for RNG to be placed on the natural gas commercial pipeline system, we would still need to create different terms to differentiate whether or not biomethane is placed on the natural gas commercial pipeline system, and the commenter does not explain how changing terminology would further improve program design. In fact, we believe that such a broad definition of RNG would ultimately lead to confusion on the part of stakeholders and inconsistent adherence to the regulatory requirements likely resulting in the generation of invalid or fraudulent RINs.

Pipeline specifications for RNG are necessary to ensure that the RNG producer will (a) inject into the natural gas commercial pipeline system and (b) do so in a manner that the RNG can be used to produce and be used as transportation fuel consistent with CAA and EPA regulatory requirements. As such, defining that RNG meet the applicable pipeline specifications is a key element of ensuring that the RNG qualifies under the RFS program. Given these considerations, we are finalizing as proposed the requirements that RNG be placed on a commercial pipeline and that RNG meets the specifications for the commercial pipeline.

Comment:

One commenter recommends that the definition of RNG production facility be adjusted to remove references to a location since RNG facilities may be co-located with a biogas production facility. They recommend the following language: “RNG facility means the equipment and process where biogas is cleaned and conditioned to RNG.”

Response:

In the RFS program, facilities can have multiple activities associated with them. For example, a single facility can be a renewable fuel production facility, a biointermediate production facility and a refinery. We did not propose to change this structure of how we categorize facilities to prohibit them from having multiple activities associated with them under our regulations. We believe this makes compliance with the regulations easier for regulated entities by only requiring a single engineering review. In contrast, defining a facility using processes and equipment as the commenter suggested can prevent a facility from registering as both a RNG production facility and a biogas production facility. The commenter has not provided a reason why requiring co-located processes to be registered as separate facilities would be more beneficial or reasonable than our current approach. Given the benefits of having facilities register with multiple activities, we are not modifying the definition of RNG production facility to be defined by equipment and processes. We have updated the definition to replace ‘location’ with ‘facility’ to be consistent with how other facilities are defined in 40 CFR part 80.

Comment:

One commenter recommends deleting the definition of treated biogas. The commenter states that this phrase is only used once in the proposed regulations and that EPA does not explain how this differs from RNG or the purpose of this definition. The commenter also recommends removing the location where this definition is referenced.

Response:

As defined in the NPRM, treated biogas is not placed on a commercial pipeline whereas RNG must, among other things, meet pipeline specifications. Treated biogas is intended to include biogas that undergoes significant processing but is used as transportation fuel in a biogas closed distribution system. As discussed in Preamble Section IX.B, this system is more straight-forward than RNG being placed on a natural gas commercial pipeline system and allows for different regulatory requirements to ensure that a biogas-derived renewable fuel is produced from renewable biomass and used as transportation fuel. Defining treated biogas allows for the requirements for interconnected natural gas commercial distribution systems and isolated biogas closed distribution systems to be treated differently. Given the desirability of having a more streamlined regulatory structure for biogas closed distribution systems, removing treated biogas as a defined term would mean only that we would need to create a different term to differentiate between the two regulatory frameworks in its stead.

We have adjusted the definition of treated biogas to clarify exactly what processes differentiate it from biogas and to more clearly specify when parties should measure the volumes of treated biogas versus the biogas and renewable CNG/LNG. These changes clarify our intent with the use of the term treated biogas and should address the commenter's underlying concerns.

Comment:

One commenter recommended clarifying the term 'this subpart' in the definition for 'fuel for use in an ocean-going vessel'

Response:

As discussed in Preamble Section IX.G, we relocated the definitions that were in 40 CFR 80.1401 to 40 CFR 80.2 to consolidate the appliable definitions in a single location. Consistent with the commenter's recommendation, we have updated this definition (and others that inadvertently were not updated) to change subpart to part, since this definition is not in a subpart and should apply to the entirety of 40 CFR part 80.

Comment:

One commenter noted that some form of upgrading is typically required prior converting raw biogas into renewable CNG/LNG. Given this, the commenter did not see how the definitions EPA proposed preclude an RNG facility from being part of a biogas closed distribution system. The commenter states it is not clear how an RNG producer can comply with both the requirements for biogas closed distribution systems and RNG.

Response:

To clarify the role of each facility, we have removed the definition for raw biogas and updated the definitions for biogas, treated biogas, and RNG. We modified the definition of biogas to be inclusive of what we had proposed to be raw biogas and included language to more clearly distinguish biogas from treated biogas and RNG. We specify that RNG must be placed on a natural gas commercial pipeline system and that treated biogas is gas that is not placed on such a system.

In the framework of the regulations, an RNG producer must inject RNG on a natural gas commercial pipeline system to generate RINs, as well as meet all other applicable requirements for RIN generation. Since a biogas closed distribution system does not involve injecting onto a natural gas commercial pipeline system, it cannot, by definition include an RNG producer. To clarify, a facility may perform the same upgrading steps as an RNG producer, they would just not be subject to the regulatory requirements of an RNG producer. The reasoning behind the different regulatory regime for biogas closed distribution systems is discussed in Preamble Section IX.B.

Comment:

One commenter stated that changes in terminology from how the market defines these terms can create confusion as to what are the applicable requirements.

Response:

We have updated the definitions based on commenter suggestions to better align with industry usage of the terms, as described above, while still ensuring that they fit within the framework of the program.

Comment:

One commenter stated that the regulatory provisions do not appear consistent with the definitions of raw biogas, biogas, and RNG or even other regulatory provisions, rendering several of the provisions vague and confusing. The commenter elaborated that this is particularly troubling when EPA is proposing to require many new parties not familiar with EPA fuel regulations (e.g., biogas producers) to be subject to regulation under the RFS program.

Response:

Based on the comments received by this commenter and others, we have updated the regulatory provisions and definitions to be consistent with one another, which should make the regulations clearer for all parties, especially those not previously familiar with the RFS program.

10.7 Registration

10.7.1 General Registration Comments

Comment:

One commenter suggested that EPA should consider flexibility for farmers, small businesses, and governmental entities that do not want to have to register in the RFS program but should be able to partake in efforts to reduce greenhouse gas emissions in the transportation fuel sector.

Another commenter suggested that EPA should consider a process that simplifies and expedites registration approvals to allow for new cellulosic project startups.

Response:

As discussed in Preamble Section IX.H.1, registration of key parties is a necessary component of the RFS program because it is where parties demonstrate to EPA that they can produce products (e.g., biogas, RNG, and biogas-derived renewable fuel) that meet CAA and EPA regulatory requirements. To mitigate administrative burden, we have streamlined the registration process for biogas producers under biogas regulatory reform especially when compared to the previous biogas provisions. Under the previous biogas provisions, a RIN generator would have to demonstrate compliance for each party in their biogas disposition/generation chain. As discussed in Preamble Section IX.A.3, this could encompass many parties over thousands of miles and involved the creation and maintenance of contractual relationships between each party in the chain. This approach virtually guaranteed that small entities could not directly participate in the RFS program. Under the biogas regulatory reform provisions, parties no longer must create and maintain extended contractual networks in order to participate in the program and instead will have to comply with a set of focused regulatory requirements on key parties. For biogas producers, this includes a limited set of registration and reporting requirements that focuses on the feedstock and method that the biogas production facility utilizes to produce biogas. We believe this streamlined registration process will help simplify and expedite registration acceptance as suggested by one commenter.

As discussed in Section IX.A.4, the biogas regulatory reform provisions are necessary to ensure that biogas-derived renewable fuels are produced from renewable biomass and used as transportation fuel consistent with CAA and EPA regulatory requirements. We also note that biogas regulatory reform is necessary to allow for uses of biogas other than to produce renewable CNG/LNG under the RFS program, as these provisions are necessary to mitigate the increased double counting opportunities that would result from allowing multiple uses of biogas. Because we are finalizing biogas regulatory reform, we are also allowing for the use of biogas as biointermediate and RNG as a feedstock, which should allow for future opportunities for the expanded production and use of advanced and cellulosic biogas-derived renewable fuels. We expect that farmers, small businesses, and governmental entities will be able to utilize these new opportunities under the biogas regulatory reform provisions.

Comment:

One commenter suggested that EPA should prioritize biogas producers in existing CNG/LNG supply chains over new entrants and eRINs participants when implementing the new registration requirements. The commenter suggested that prioritizing existing facilities would ensure that existing operations would not be disrupted if prioritized.

Response:

EPA generally reviews and accepts registration submissions in the order they are received, and it would be inappropriate to prioritize one party's timely submission over another. However, we believe the phased implementation dates discussed in detail at Preamble Section X.F will allow EPA to focus on the influx of registration submissions from existing registrations to address the commenter's concerns without prioritization. We are finalizing an implementation date for new registrants of July 1, 2024, and an implementation date for existing registrants of January 1, 2025. This phase-in approach to implementation will allow EPA to develop key functionality in its registration and reporting systems for new registrants by July 1, 2024, and stagger the submission of updated registration information from existing registrants (i.e., by having those registration submissions due October 1, 2024) in a manner that should allow for the timely review and acceptance of registration submissions by both new and existing registrants.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter suggested that EPA clarify when an updated engineering review is required. The commenter noted that the reference to timing for the next three-year engineering update is unclear and suggested that EPA should simply specify a date when it would be required, such as January 1, 2025, to reduce the burdens on third party engineers, give existing facilities more time to come into compliance, and to better facilitate registration of facilities under the eRIN provisions. The commenter highlighted that EPA proposes to allow a biogas closed distribution system RIN generator to defer submitting an updated engineering review for any facility in the biogas closed distribution system as specified in 40 CFR 80.1450(d)(1) before the next three-year engineering review update is due as specified in 40 CFR 80.1450(d)(3). The commenter said that EPA did not explain why it is only deferring engineering reviews for a biogas closed distribution system RIN generator and that EPA also should be clear as to the timing of these updates and allow all existing facilities to defer updating their registration.

Response:

To clarify for the commenter, we are finalizing that for existing biogas registrations, parties that need to comply with updated requirements in 40 CFR 80 subpart E must submit registration updates, including engineering reviews if necessary, by October 1, 2024. We anticipate that this would provide EPA enough time to review the submissions prior to the implementation date for these facilities of January 1, 2025.

We are allowing engineering review updates to be submitted as part of the regularly scheduled three-year engineering reviews for biogas closed distribution systems that do not require updates under the new regulations (see 40 CFR 80.135(b)(2)(ii)). We did not extend this provision to biogas producers, RNG producers, and RNG RIN separators because these parties have different requirements under the new regulations, so they will have to update their registration at the implementation date.

As discussed in Preamble Section X.B, we have clarified the timing of engineering review updates in 40 CFR 80.1450(d)(3).

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

Multiple commenters said that in the proposal EPA requires applicants to submit registration applications at least 60 days prior to January 1, 2024, though elsewhere, EPA's proposed regulations state that "[p]arties required to register under § 80.145 may register with EPA beginning on the effective date of the final rule." The commenter asks for clarity on which of these two registration deadlines (October 31 or December 31, 2023) it intends biogas producers to meet.

Response:

As discussed in Preamble Section X.F, we are requiring that parties not already registered for the generation of RINs under the existing biogas regulations register under the new biogas regulatory reform requirements beginning July 1, 2024. Because we are not finalizing the proposal that would have necessitated EPA to begin accepting registrations at the effective date of the rule, the comment is no longer directly applicable. However, to aid in stakeholder understanding of the new biogas regulatory reform implementation dates, we believe it useful to describe how the registration submission dates interact under the final rule.

Under the biogas regulatory reform provisions, new registrants must submit registration submissions 60 days prior to the anticipated production of biogas under the RFS or for generation of RINs (see 40 CFR 80.135(b)(1)). This is the same requirement for other types of fuel and allows time for EPA to review the submission and identify any deficiencies, and for the party to resubmit a more complete, accurate submission. While we are including language that states that parties may produce biogas, RNG, or generate RINs prior to the 60-day limit if EPA accepts their registration in advance, parties that fail to submit information at least 60 days prior to their anticipated production/RIN generation date cannot assume that EPA will accept their registration early because EPA's ability to accept a registration depends largely on how accurate and complete the submission is, which varies significantly based on EPA's experience over the last 13 years of implementing the RFS program.

To accommodate the 60-day deadline for registration deadlines, we intend to make available to potential registrants the needed functionality in the registration system at least 60 days prior to

July 1, 2024. We also intend to provide more time if possible to accommodate parties that wish to submit registration information early.

For existing registrants, we are requiring that those parties must submit updates to their registration information by October 1, 2024. While this is 91 days in advance of the December 31, 2024 end date for RIN generation under the previous biogas provisions, we are allotting EPA staff 31 extra days to ensure that they have enough time to review the anticipated influx of updated registration information for existing registrants.

As we have done for other recent major rulemakings, we intend to conduct stakeholder outreach related to the implementation for the new regulatory provisions. We intend to disseminate more information related to system functionality at such outreach well in advance of the July 1, 2024, implementation date.

10.7.2 Biogas Producer Registration

Comment:

Multiple commenters state the biogas producers should not need to register.

Response:

Biogas producers are critical to the production of renewable fuel from biogas because biogas producers directly oversee the production of biogas from renewable biomass. However, biogas producers can potentially also be a source of fraud in the system, as it is possible to mix fossil natural gas into biogas. In addition, the biogas producer is responsible for the proper allocation the biogas to various feedstocks, D-codes, and verification statuses necessary to ensure that RINs are validly generated under EPA approved pathways. Requiring these parties to keep records, submit reports, undergo engineering reviews, and register with EPA is thus essential for a program that can be effectively overseen and enforced. While any person that causes another person to violate a provision is also liable for the violation,[135] having direct registration and reporting by key parties in the chain allows for efficient oversight to identify a violation. Given this, we are finalizing as proposed that biogas producers must directly register under the RFS program. We address specific reasons commenters have offered for not having biogas producers register later in this subsection.

Comment:

Biogas producer commenters expressed concern that registration would subject to them to liability and additional burdens. One commenter explained that for municipalities, EPA's proposed requirements could violate or be inconsistent with their procurement policies and may result in them no longer participating in the program.

Response:

We believe subjecting biogas producers that choose to participate in the program to liability if they don't comply with Clean Air Act or regulatory requirements is necessary to ensure adequate programmatic oversight; commenters have not offered an alternative approach that would provide commensurate oversight and enforcement as having biogas producers register as a condition of participation. We also note that the biogas producer would be potentially liable for any violation associated with biogas production under the previous biogas provisions, the difference between biogas regulatory reform and the previous biogas provisions is that the biogas producer will now have to directly comply with specified regulatory requirements under the RFS program.

It is worth highlighting that there is no requirement that these parties participate in the RFS program. Revenue from RINs under the RFS program can provide them with an additional source of income to fund their operations and improve profitability. However, it will be their

[135] As specified in 40 CFR 80.1461(a)(2).

business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

Comment:

Commenters express that the registration requirement for biogas producers is unnecessary since the QAP process helps ensure that there is no double counting or fraudulent RIN generation.

Response:

As discussed in RTC Section 10.12, QAP is not meant to be a replacement for enforceable regulatory provisions that ensure that biogas-derived renewable fuels are produced from renewable biomass and used as transportation fuel consistent with CAA and EPA regulatory requirements. In addition, the QAP program is not designed for obtaining records from parties other than the party which is registered with EPA and participates in QAP. If biogas producers were not required to register as suggested by the commenters, under the expanded program that allows multiple uses for biogas the QAP providers would not necessarily have direct access to records about feedstock information necessary to verify the RINs, increasing the risk that they verify invalid RINs. For example, if we required the RNG producer to register and report digester feedstock information, if they are a different party than the biogas producer, QAP providers may not be able to verify the records from the biogas producer are correct and this could lead to generation of invalid RINs. Likewise, the QAP provider would also be further separated from the biogas producer and may lack the ability to investigate to adequately verify these RINs. In summary, QAP does not provide the same level of oversight provided by biogas producer registration.

Comment:

One commenter recommended that EPA simply have a paper trail without having biogas producers register. EPA could require RNG producers obtain monthly reports from the biogas sites on the designated use of the biogas and the volume supplied consistent with proposed 40 CFR 80.150(b). Another commenter said that rather than requiring biogas producer registration, EPA can require RNG producers to provide information on the biogas it receives.

Response:

Transferring of documents from the biogas producer without having them register does not provide the level of compliance and oversight necessary given the expanded role in biogas in this rule. This also does not address the concern, as discussed in more detail in Preamble Section IX.A.4, that biogas producers could claim to send the same volume of biogas to multiple facilities with each not knowing that it is using the same volume of biogas as the other facilities. The commenter does not adequately explain how document transfer alone is sufficient for the program to be effectively overseen.

Comment:

One commenter said that requiring landfills to participate in the program via registration would add an entirely new party to the regulatory requirements when all that is relevant for RNG production is inlet flow volumes and methane content.

Response:

EPA must ensure proper oversight and prevent double counting of RINs in the RFS program. We believe the best way of doing so is to require biogas producers, including landfills, to register under the program, and commenters have not provided an alternative approach. Having biogas producers register alleviates our double counting concerns for the following reasons:

- Ensures that the RNG producer is not adding non-qualifying gas for upgrading.
- Tracks the volume of biogas effectively in EMTS.
- Allows EPA to hold parties that are closely involved in the value chain liable.

Comment:

One commenter stated that the proposed registration requirements are too uncertain to allow for implementation before the proposed deadline for the Set period. The commenter recommended existing RFS participants be grandfathered into the program until the registration requirements are finalized and proliferated through the marketplace, which they said would reduce volatility.

Response:

We did not propose nor are we finalizing that parties must comply with the biogas regulatory reform provisions prior to the implementation date established in this action. As discussed in Preamble Section IX.F, we are allowing more time for both existing and new registrants to comply with the biogas regulatory reform provisions. Parties covered by an existing registration would have until January 1, 2025 to come into compliance with the new provisions, and new registrants would have to begin using the new provisions starting on July 1, 2024. We believe this will provide adequate time for information to be proliferated through the marketplace.

Grandfathering existing participants would undermine our stated need for biogas regulatory reform, as discussed in detail in Preamble Section IX.A.4, and significantly increase the amount of confusion in the marketplace because two sets of regulatory provisions could apply for an extended period of time making it difficult if not impossible to oversee the program.

Comment:

Multiple commenters suggested that EPA exempt producers or landfills from the registration requirement if they are not producing renewable LNG/CNG on site, serving as the biogas closed distribution system RIN generator, or producing renewable electricity on site.

Response:

The commenter does not fully explain why EPA's rationale for the biogas producer requirements (e.g., to prevent fraud and provide adequate oversight) does not apply to those types of biogas producers. We believe it is important that these biogas producers register because as discussed in Preamble Section IX.H.1, these registration requirements are needed to ensure that biogas producers can produce biogas that qualifies under the CAA and EPA regulatory requirements. At registration, these producers must demonstrate their facility's production capacity, how biogas will be measured consistent with EPA regulatory requirements, and how the biogas will be used consistent with EPA regulatory requirements. However, to simplify the registration process for landfills, we have specified in the regulations at 40 CFR 80.135 the specific regulatory requirements that apply to each biogas production facility by form of anaerobic digestion. Because biogas produced from landfills is relatively straight-forward compared to, for example, agricultural digesters, these requirements are narrower.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter said that these new registration and reporting burdens and increased compliance costs will likely limit the participation of cellulosic biofuel producers in the RFS.

Response:

The commenter does not provide any data or reasoning to support how these registration and reporting requirements would lead to a decrease in program participation, or what particular provisions may result in increased costs. Given this lack of specificity, it is unclear what changes commenters would have us make to the proposed provisions. As discussed in Preamble Section IX.A.4, the biogas regulatory reform provisions are necessary for us to allow for multiple uses of biogas under the RFS program in a manner that avoids double counting and invalid RIN generation. Because we are finalizing biogas regulatory reform in this action, we are allowing biogas to be used as a biointermediate and RNG as a feedstock to produce biogas-derived renewable fuels other than renewable CNG/LNG. This allowance should allow parties to produce more biogas-derived renewable fuels over time.

It is worth highlighting that there is no requirement that these parties participate in the RFS program. Revenue from RINs under the RFS program can provide them with an additional source of income to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

Comment:

One commenter requests clarity on what vehicle fleet means in the NPRM § 80.145(c)(5)(iv). They provide an example of stating that the facility serves a municipality, private fleet, or public retail station. They proposed updated language.

Response:

In the NPRM, we intended that the biogas closed distribution RIN generator would provide a description at registration describing the vehicle fleet including how they would be fueled, similar to the commenter's suggestion. We have updated the definition to clarify that the registering party provide a description of the vehicles and dispensing station.

Comment:

One commenter said that proposed registration requirement at 40 CFR 80.145(f)(5) requires information related to biogas and RNG measurement, but EPA's proposed regulations do not require RNG producers to measure biogas.

Another commenter suggested that EPA should strike the requirement at proposed 40 CFR 80.105(f)(1)(i) that biogas producers continuously monitor biogas that is being sent offsite because it is redundant and unnecessary. The commenter contended that biogas producers who currently supply biogas to onsite RNG, electricity, or CNG/LNG facilities do not need to continuously monitor outgoing biogas because the onsite facilities receiving the biogas already perform the continuous monitoring, which will allow biogas to be tracked to their operations and reported under the RFS program.

The commenter said that it makes little sense to require continuous outgoing monitoring by biogas producers and incoming monitoring by facilities that use biogas to produce renewable fuels, and that the proposal would require installing the same measuring equipment in two different places along a single pipeline, when one monitoring location is enough. The commenter argued that this would place significant new compliance burdens on biogas producers, and could discourage some from entering the marketplace, when a second flowmeter adds little additional security to the RIN monitoring framework.

The commenter suggested that it makes more sense to continuously measure biogas at only one location in the pipeline. Because the onsite producers already continuously monitor incoming biogas, EPA can rely on their measurements without imposing similar requirements on biogas producers. The producers will also be subject to third-party engineering reviews and QAP, which offer further assurances against miscounting or fraud. Continuous monitoring will needlessly force biogas producers to install additional measuring equipment. The commenter requested that EPA should eliminate the proposed continuous monitoring requirement for biogas producers.

Response:

In our proposal we intended that biogas only need to be measured by one party. We are requiring that biogas producers measure biogas and RNG producers measure RNG, since both parties are the best equipped to know what feedstocks and processing steps were used. To the extent that the RNG producer needs information about biogas, it can acquire that information in PTDs associated with the biogas batch.

We note the discrepancy with the point of measure and the language in proposed 40 CFR 80.145(f)(5) (which is being finalized as 40 CFR 80.135(d)(3)), and we have removed biogas from the provision that RNG producers provide this measurement information at registration. The updated language does not require RNG producers to provide information about biogas measurement at registration.

We also clarified in the regulations how RNG and biogas must be measured and how parties should describe the measurement at registration. We also modified the paragraphs for RNG (40 CFR 80.135(d)(3)) and biogas (40 CFR 80.135(c)(3)) to be consistent.

Comment:

One commenter states that EPA does not provide a basis for requiring a RIN generation protocol in 80.145(f)(7). The commenter states that protocols may remove flexibility for RIN generation that parties currently operate under. The commenter notes that virtually all RNG producers participate in QAP, which involves review of RIN generation. The commenter also states that if RNG producers were required to report the biogas volumes, there should not be discrepancies between biogas producers and RNG producers.

Response:

As stated in the NPRM, we proposed modifying regulatory requirements for renewable CNG/LNG pathways to ensure the program can be effectively overseen and that biogas is not double-counted.[136] A RIN generation protocol provides EPA with the knowledge that the renewable fuel producer generates RINs consistent with the regulatory requirements. EPA needs these documents to determine if meter locations are compliant with the regulatory requirements and to efficiently identify discrepancies in RIN generation especially in cases where multiple RNG producers inject at the same pipeline interconnect. RNG producers and biogas closed distribution system RIN generators must demonstrate at registration that they can generate RINs consistent with the applicable regulatory requirements to avoid the invalid generation of RINs, which can be burdensome to retire or replace.

Comment:

Multiple commenters said that requiring the biogas producer to register would disincentivize or exclude market participants from participating in the RFS program.

One commenter said that requiring cellulosic biofuel feedstock suppliers to register under the RFS is overly burdensome. Expanding these requirements will limit participation in the RFS and hamper growth within the category.

One commenter stated that EPA does not require the registration of farmers producing corn and soybeans for ethanol production. The commenter said that the proposal would lead some farmers, landfills, or wastewater treatment plants to avoid the RFS altogether, and that there is no

[136] 87 FR 80693.

tangible benefit to requiring registration of each of these entities. The commenter also noted that the QAP process today has been accepted by the industry and provides EPA with sufficient authority to deter potential fraudulent RIN production or double counting.

Multiple commenters requested allowing delegation for certain biogas producers. Commenters said that RFS is not a core competency of many parties that generate little biogas. They said that the proposed rule creates new liabilities and compliance burdens. The commenters said that the QAP process ensures that the production of biofuel matches feedstock purchases.

One commenter said that the proposed provisions are tantamount to requiring every farmer that grows an ear of corn for eventual ethanol production to register under the program.

Response:

The commenters did not provide any data or analysis to back their assertions that participating in the program would no longer be profitable if they had to register. Regardless, as discussed in more detail in Preamble Section IX.A.4 and IX.H.1, we believe that any incremental burden associated with registration of biogas producers is warranted in order to ensure that EPA can effectively oversee and enforce the program. Because biogas producers are the party that produces biogas from renewable biomass under EPA approved pathways, they are in the best position to ensure that the feedstocks being used qualify; having them register is the most efficient and effective way for EPA to verify this critical step of RIN generation.

We acknowledge that not all parties may be intimately familiar with the RFS implementation tools and procedures. However, any program participants may engage with third party service providers that provide services such as registration updates and compliance reporting submission.

As discussed in RTC Section 10.12, QAP is not a replacement for an overseeable regulatory program. In order to verify biogas production to ensure that qualifying renewable biomass feedstocks are used and double counting is not occuring, biogas producers registering under the program must be liable for the reports submitted by them or on their behalf.

Finally, the commenter compares registration requirements for biogas producers to providing registration requirements to feedstock providers like farmers. There are critical differences between producing biogas that is turned into RNG and producing corn for ethanol that warrant different treatment in this instance. Primarily, there is a high potential for fraud due to the fungibility of natural gas and RNG that does not exist for other feedstock and pathways and that makes requiring biogas producers to register both necessary and justified. As described further in Preamble Section IX, biogas is now eligible for use as a biointermediate, which increases the complexity of the program and further justifies the new registration requirements as needed to mitigate the risk of double-counting RINs. We are finalizing these new registration requirements to fully realize these benefits while maintaining our ability to oversee the program.

It is worth highlighting that there is no requirement that these parties participate in the RFS program. Revenue from RINs under the RFS program can provide them with an additional source of income to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

10.7.3 RNG Producer Registration

Comment:

Multiple commenters do not support identifying pipeline specifications at registration.

One commenter said that EPA does not have authority to accept pipeline specifications or regulate pipeline quality.

One commenter says that if such information is required, EPA must make clear that it is for informational purposes only and not be part of attest engagement or QAP review.

One commenter stated that EPA does not provide an explanation why information on fuel quality is required to track RNG for purposes of avoiding double counting, particularly when the molecules need not be traced and noted that this is not required for any other biofuel in the RFS regulations."

One commenter noted that existing pipeline specifications typically have a process and procedure for addressing the potential for off-spec batches and claimed that EPA did not explain how, as long as the pipeline allows the RNG, slight deviations from the specifications could render the RNG as non-qualifying. The commenter further noted that the RNG is still derived from renewable biomass, the GHG emissions reductions are still being met, and the fuel is still being used for transportation fuel, displacing fossil fuel. The commenter claimed that there is no basis to require the information for registration or to require ongoing monitoring and no basis to potentially render the RINs invalid. As such, the commenter suggested that there is no basis for EPA to require this information be "accepted" at registration or to require ongoing monitoring or verification.

Response:

Pipeline specifications are necessary at registration since the definition of RNG depends on the pipeline specifications.[137] The definition of RNG, in turn, includes meeting the applicable pipeline specifications because it is necessary to ensure that the RNG producer will (a) inject into the natural gas commercial pipeline system and (b) do so in a manner that the RNG can be used to produce and be used as transportation fuel consistent with CAA and EPA regulatory requirements. As such, requiring that RNG meet the applicable pipeline specifications is a key element to ensuring that the RNG qualifies under the RFS program. We believe it is imperative to show that the product of the RNG producer meets the requirements for RNG. If this was not submitted, it would be more difficult for EPA and third-party auditors to determine compliance.

Note that in the NPRM we stated that we are implementing existing guidance EPA already had issued for biogas.[138] That guidance specified that parties would need to submit pipeline specifications at registration was specified; we have been collecting such information from RIN

[137] For more information about the definition of RNG, see RTC Section 10.6.
[138] EPA-420-B-16-075 (September 2016).

generators under the previous biogas regulations since 2016. In incorporating this provision into the regulations, EPA decided to require pipeline specifications rather than defining our own specifications due to the variability in pipeline specifications across the country.

As discussed in this section, we are removing the requirements for certificates of analysis at initial registration given comments that it could delay registration, but we are still requiring them at the 3-year registration update. Unlike the certificates of analysis, the pipeline specifications are necessary to determine compliance with the definition of RNG if any violations occur during the first few years of operation. For these reasons we are continuing to require pipeline specifications at registration for RNG producers, and this information may be used by EPA and QAP providers to determine compliance. We did not propose and are not finalizing that RNG quality and pipeline specifications be reviewed as part of the attest engagement.

We also did not propose and are not finalizing a process to accept or reject pipeline specifications at registration, but we are requiring them to be submitted to EPA to ensure RNG is subject to pipeline specifications and to ensure that RNG produced from the RNG production facility is capable of being injected on the natural gas commercial pipeline system. We are also requiring testing for 3-year updates to ensure that the facility is producing RNG that conforms with those specifications.

Comment:

One commenter recommended expanding the allowance of parties currently registered to be deemed registered to include parties different than the RNG producer or CNG/LNG producer in a closed distribution system. The commenter also recommended removing the exceptions since with the exceptions many RNG producers will likely have to update registrations. The commenter recommended allowing parties registered prior to January 1st 2024 to continue to operate under current regulations until January 1st 2025.

Response:

As discussed in the NPRM and Preamble Section IX.A.4, the biogas regulatory reform provisions are necessary to ensure adequate oversight and to avoid double-counting when biogas can be used for more than just CNG/LNG.[139] The commenter does not explain how grandfathering facilities or delaying compliance with these provisions will ensure adequate oversight and avoid double-counting, since during the time period EPA proposed, biogas will be able to be used for more than just CNG/LNG. In fact, we believe that an extended period of having multiple sets of requirements apply for biogas, RNG, and biogas-derived renewable fuels would result in a significant amount of confusion in the marketplace resulting in non-compliance and invalid RIN generation.

Comment:

One commenter states that parties should be deemed registered so long as updated registrations are submitted to EPA by November 1st, 2024 or January 1st 2025. The commenter requests that

[139] 87 FR 80692-80693.

EPA clarify that the facilities can continue to generate RINs until EPA approves the updated registration and except these "updates" from the requirements in proposed § 80.145(b)(4).

Response:

Allowing parties to register under different requirements by submitting a registration at a certain time poses a number of challenges that the commenter does not address.

First, it can incentivize submitting incomplete or unclear applications. This places more burden on EPA to review these applications, contact companies for correction, and then re-review the update. The net result of this could be a delay in accepting of registrations. Our regulations should incentivize complete applications.

Second, this could cause the generation of invalid RINs. For example, if the submission is not complete or the facility is not in compliance with the regulations, and if the facility has generated RINs, those RINs may be invalid. EPA rarely accepts the very first registration submission because registration submissions are typically incomplete, inaccurate, or inconsistent with the applicable regulatory requirements.

Third, if a party can generate RINs for a biogas/RNG produced prior to submitting a compliant registration submission, there would be no incentive for parties to submit a compliant registration submission in a timely manner. This would require more time for EPA to follow up with companies to make sure they have submitted adequate information.

Fourth, it can be difficult for auditors to determine the correct date by when RINs can be generated when facilities submit registrations multiple times due to errors in their registrations.

In all, the suggestion would likely increase the time it takes for EPA to review registrations, make it more difficult to determine compliance, and increase the likelihood of invalid RINs. All of these factors make it more difficult to oversee the program, contrary to the goals of biogas regulatory reform.[140]

Comment:

One commenter thought that proposed registration regulations at 80.145(f)(2) should reference 80.1450(b)(1) instead of 80.1450(b)(5)(ii).

Response:

We recognize that 80.1450(b)(5)(ii) does not exist in the regulations, we intended it to be 80.1450(b)(1)(ii) and have changed it to make it consistent.

[140] 87 FR 80693.

Comment:

One commenter stated that EPA indicates it is proposing to require RNG facilities to demonstrate their production capacity at registration; however, the regulations at proposed 40 CFR 80.145(f)(3) only requires annual volume totals of the RNG produced for each of the last three years. The commenter suggested that EPA should remove this requirement or clarify how this requirement applies to new facilities and facilities with less than three years of operation. The commenter also suggested that these facilities should not be required to update their registrations to provide this information until the required three-year update. The commenter requested that EPA should make clear that any such data does not define a baseline or cap on production because RNG production facilities may not have a steady state of production or could implement expansions and improvements to increase their production capacity. The commenter argued that RNG production facilities should not be restricted to the production capacities listed in their registration materials.

Response:

Our intent was that RNG production facilities without historical data will still be able to register under our program. RNG producers can indicate whether or not they have historical production information for a facility as part of their registration submission. We have updated the applicable regulatory language to clarify that RNG producers would supply capacity information 'if available.' We did not intend registrants would need to update their registration with production data generated since submitting their registration information because this information will be collected as part of the periodic reporting requirements discussed in Preamble Section IX.H.2.

To further clarify this issue, we have aligned the regulatory language on capacity information for biogas and RNG producers. We chose to update the RNG language to be consistent with the language used for biogas, instead of using the language provided by the commenter, to align with the stated goal of biogas regulatory reform to have a system that can be more easily overseen and to provide clarity to regulated parties. The new language is also similar to the commenter's wording by including 'if available' and 'prior to registration submission,' and we believe this addresses the commenter's concerns.

Production capacity information that is not associated with a grandfathered pathway, as described in 40 CFR 80.1403(c), does not place a cap on production; however, biogas and RNG producers, like biointermediate and renewable fuel producers, are responsible for maintaining the accuracy of their registration submissions with EPA. Failure to update registration information is a potential violation of the regulatory requirements and meeting all applicable registration requirements is a requirement to generate RINs under 40 CFR 80.1426(a)(1). Expansions and improvements that increase production capacity may require a facility to update their registration, and RNG producers must do so in the timeframes specified in the registration regulations at 40 CFR 80.135 and 80.1450 as applicable. Failure to update capacity information may result in EPA initiating the deactivation procedure for the RNG production facility under 40 CFR 80.1450(h). We encourage RNG producers to update capacity information in a timely manner to avoid the generation of invalid RINs and the deactivation of their registrations.

Comment:

Multiple commenters stated that certificates of analysis should not be required at registration since they can delay registration.

Response:

We recognize that requiring certificates of analysis (COAs) at initial registration can delay registration because the facility must be operational prior to taking the sample. Furthermore, sending the sample to a laboratory for analysis adds additional time. Submission at registration of the COAs also requires additional time for EPA to verify that COAs are consistent with the regulatory requirements. The benefit of this analysis is to show that the upgraded gas is RNG that can be used as transportation fuel under the RFS program because it meets the pipeline specifications.

Given our experience reviewing certificates of analysis under the previous biogas provisions, we realize that to reduce potential non-compliance, it is most important to show that compliant RNG is produced at regular intervals. For certifications of analysis, showing the initial batch is compliant provides only marginal benefit to regular testing. Given the disruption caused at registration and the benefit of showing this information at regular intervals, we are modifying the requirements relative to the proposal to remove the requirement to submit certificates of analysis from initial registration and now only require this information during 3-year engineering reviews, as discussed in Preamble Section IX.M.1. We believe this will still allow oversight that the facility is producing RNG without delaying registration.

Comment:

One commenter stated that proposed regulations at 40 CFR 80.145(f)(8) requires a description of how RNG producers will allocate RINs at a pipeline interconnect that also has RNG injected from other sources. The commenter contended that EPA did not provide any explanation of the need or basis for this requirement, as required by the Clean Air Act and that EPA provided no indication of whether this information is available to all RNG producers or why RINs need to be "allocated" if RINs are based on the RNG injected into the pipeline by each individual production facility.

Response:

The requirement to provide a description of how RNG producers will allocate RINs at a pipeline interconnect that also has RNG injected from other sources is necessary to ensure adequate oversight and avoidance of double-counting when biogas can be used for more than just CNG/LNG.[141] This requirement helps ensure that, for facilities that share an interconnect, the total amount of RINs generated is limited by the amount of RNG injected into the pipeline. This check allows EPA to verify that RINs are being generated only for fuel that meets the statutory definition of renewable fuel, which includes being produced from RNG that is produced from

[141] 87 FR 80692-80693.

qualifying renewable biomass.[142] If more RINs are generated than is appropriate based on the amount of RNG injected into the pipeline, this reported information assists EPA and third-party auditors in identifying volumes of fuel that are not produced from qualifying renewable biomass and thus invalid RINs. This requirement comes from our experience overseeing biogas programs where multiple facilities share an interconnect. To avoid this situation, we proposed that facilities explain how they will allocate RINs at registration.

To help explain why allocation of RINs may be necessary, here is an example. Five facilities share an interconnect and each produce ten million BTUs of biogas of biogas to be sent to the pipeline. During one month, the pipeline cannot accept some of the biogas due to a disruption of service or because the biogas did not meet pipeline specification and ten million BTUs are flared after each facility has measured their biogas individually. Each facility needs to know how many RINs they should generate. If each facility generates RINs from ten million BTUs, more RINs would be generated than the amount the RINs corresponding to the amount of RNG placed on the commercial pipeline. This would create invalid RINs. Without coordinated equations that clearly explain how many RINs should be generated, it would be difficult for multiple QAP providers to identify the issue, since QAP providers do not see information for facilities for which they do not provide QAP services.

Having coordinated equations also allows EPA to more clearly identify the facility that more directly contributed to the violation, which may reduce the chances that EPA moves forward with an enforcement action against all facilities, simplifying enforcement. EPA believes this requirement is necessary to adequately oversee and enforce the validity of RINs and the commenter has not provided any information to indicate otherwise.

[142] CAA section 211(o)(2)(A)(i) requires EPA to promulgate and revise regulations to ensure that transportation fuel sold or introduced into commerce in the United States contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel. The EPA uses RINs to represent volumes of qualifying renewable fuel.

10.7.4 RNG RIN Separator Registration

Comment:

One commenter said that the Proposed regulations at 40 CFR 80.145(g)(2) would require an initial list of locations of any dispensing stations where the RNG RIN separator supplies or intends to supply renewable CNG/LNG for use as transportation fuel. The commenter suggested that EPA should either not require this information as part of registration or should make clear that this would be for informational purposes only and updates are not necessary if there is a change or to reflect business/marketing plans.

Response:

Supplying information about the RNG RIN separator dispensing stations at registration provides a check to ensure that multiple parties are not double counting the same dispensed volume, which is necessary to ensure that renewable CNG/LNG is used as transportation fuel consistent with CAA and EPA regulatory requirements. Given this requirement helps prevent double counting, parties must also update their registration when adding or removing dispensing stations. The commenter does not provide a reason why this requirement is not necessary or should be removed. Given we still have concerns about double counting, and we believe this provision helps reduce double counting, we are finalizing this requirement as proposed.

Comment:

One commenter supports the proposal to not require engineering reviews for RNG RIN separators.

Response:

We thank the commenter for their support and are finalizing as proposed that RNG RIN separators do not need to submit an engineering review as part of registration.

Comment:

Multiple commenters state the CNG/LNG dispensers should not need to register and provided multiple reasons and alternatives as to why they should not need to register.

Concerns the commenters had around CNG/LNG dispensers registering involved:

- The proposed requirement would subject additional parties to liability and additional burdens.
- QAP providers and experienced entities help ensure that there is no double counting or fraudulent RIN generation.
- For municipalities in particular, EPA's proposed requirements for CNG dispensers to register could violate or be inconsistent with their procurement policies.
- This change will require renegotiating contracts.

- If all dispensers of renewable fuel (e.g. CNG/LNG) are required to register under the proposed rule, additional revisions may be required to the program management platforms (Central Data Exchange (CDX) and EMTS) for confidential business information. The commenter would like to allow delegation at the facility level, though it is currently done at the organization level. The commenter states that dispensing organizations may have facilities contracted with several RNG marketers or RNG producers.
- Separated RINs from the RNG RIN separators would need to be transferred again to the marketer/agent performing the contractual delivery of RNG so the RINs can be sold/monetized and that allowing marketers or agents to aggregate fuel use information is imperative to the success of the RFS program.
- The change is not warranted because there has been no showing by EPA of any fraud or double counting of RINs in the marketplace.

Commenters suggested the following alternatives:

- Allowing delegation of RIN separation duties.
- In lieu of the proposed requirements the RNG producer can seek to obtain information from the dispenser to confirm the sale of the CNG/LNG as a transportation fuel, which would provide a paper trail.

Response:

As we stated in the NPRM, we believe that the party that separates the RINs should be the party best positioned to show that RNG was used as transportation fuel, and we believe that the party dispensing renewable CNG/LNG is best positioned to show this.[143] They are the party most able to produce the documentation that natural gas was used as transportation fuel and to track and verify the use of RNG as renewable CNG/LNG independently of the RNG producers. We recognize that this may subject additional parties to registration, reporting, and recordkeeping requirements, but we believe this is necessary to reduce the risk of double counting.

Since QAP providers only verify usage attributable to their clients, QAP auditors may be unable to identify if use of RNG is being double counted by different parties with different QAP providers. Given this, QAP is not an adequate substitute for ensuring that RINs are separated only for renewable CNG/LNG that is used as transportation fuel. See RTC Section 10.12 for more detailed explanation of why QAP is not a replacement for biogas regulatory reform.

The commenter that stated that the proposed provisions may be incompatible with municipality procurement policies provided no specific example where our proposed requirements would violate or be inconsistent with their procurement policies. The commenter further failed to address why such a municipality would be unable to change their procurement policies to be compatible with the regulatory requirements. Given that no examples are provided, we cannot substantiate the claim and are not able to know what changes if any, would prevent this potential discrepancy. As such, we have not changed the regulations in response to this comment.

[143] 87 FR 80694-80696.

We designed the IT systems for implementing the RFS regulations while at the same time balancing the need for minimizing reporting burden. This includes allowing for regulated parties to choose to have third-party agents submit registration updates and compliance reports on their behalf. Ultimately, the responsible corporate officer approves which registered users, including third-party agents, have access to the regulated party's information under each of the different IT systems. The ability to add delegated system users is only under the company level (not facility level) under each of the IT systems because these systems also mirror the compliance structure of the regulations including for how RINs are managed at the company level.

In some contractual arrangements, RINs may pass from a marketer to an RNG RIN separator and back to the same marketer. This is necessary because the party best able to demonstrate use as transportation fuel should be the party that separates the RINs, just like RIN generators in our program are the entities responsible for production of renewable fuel. This is necessary to ensure that RINs are not separated multiple times for the same volume of gas dispensed for transportation use. For example, if we were to allow flexibility in RIN separation, a RIN separator may contract with multiple parties to separate on their volume, leading to double counting. In this case, none of these other parties may be aware that RINs were separated by other parties for the same volume. To prevent this from occuring, we are specifying the RNG RIN separator in this action. For a discussion of how previous cases of fraud are relevant to this rulemaking, see Section 10.1.

As mentioned by commenters, these requirements also come with additional regulatory provisions, which will likely require renegotiating contracts and may increase liability and reporting obligations. We believe a party related to the use of RNG as renewable CNG/LNG must separate the RINs for EPA to effectively oversee the biogas program. At the same time, we believe that some non-dispensing parties may also have adequate documentation to serve as RNG RIN separators. Given this, we are expanding the scope of who can be an RNG RIN Separator, which we believe can still ensure proper oversight while reducing the burden on individual dispensers to comply with the regulation. Specifically, we are finalizing that the RNG RIN separator can be the party withdrawing RNG from the commercial pipeline, producing renewable CNG/LNG, or dispensing renewable CNG/LNG. We believe all these parties have necessary oversight over the use of renewable CNG/LNG as transportation fuel. We also believe that this flexibility addresses many of the commenters' concerns.

While we are providing this flexibility, we are also concerned about double counting of volumes used as transportation purposes when separating RINs. Given this, we are finalizing a requirement that for each dispensing location, only one party may be registered with EPA to dispense renewable CNG/LNG at a time. The proposal limited the number of parties at a dispensing location to one by requiring that the RNG RIN Separator be the dispenser. By specifying this condition in this final action, we are essentially finalizing this limitation that was built into the proposal.

10.8 Reporting

Comment:

Multiple commenters noted an inconsistency between the preamble to the NPRM and the proposed regulation over how batches of biogas would be reported. In the NPRM preamble, we described the proposed batch reporting requirement for biogas producers as being for each digester at the biogas production facility, and in the NPRM regulations, we stated that batches would be done at the facility level (i.e., would not be done separately for each digester at the facility but rather in aggregate across the entire facility). Commenters highlighted that digester-level reporting would require significantly more metering to measure biogas production out of each digester, which would be expensive and questioned whether EPA needed to require so much metering to measure biogas production.

Response:

We understand commenters' concerns. We intended that the reporting level be based on facilities as specified in the proposed regulations (i.e., batches would be based on monthly aggregate facility production). We have updated the preamble to this action to reflect that biogas batches be reported at the facility-level and not by individual digester.

Comment:

One commenter opposes monthly biogas production reports. The commenter asserts that this is overly burdensome, duplicative with other state and federal regulations and potentially without justification.

Response:

Consistent with EPA's "Next Generation Compliance,"[144] we are designing the reporting regulations to improve implementation and compliance with the regulations. The biogas regulatory reform provisions require batch information from the biogas producer to be transferred to the downstream parties such as the RNG producer in order to generate RINs. Additionally, independent third parties such as QAP providers or attest auditors also depend on this information in order to verify RINs and to compare reports submitted to EPA against underlying records. Monthly batch reports of biogas allow other regulated parties, auditors, and the EPA to verify that RINs are generated consistent with the regulations, reducing the risk of double counting.

We are finalizing the monthly batch reporting requirement because it is an appropriate frequency to ensure program compliance goals without being overly burdensome. Quarterly compliance reporting deadlines would be well after when RIN generation reports must be submitted in EMTS. The reporting regulations are structured to make noncompliance with these requirements difficult so that accurate and timely information is moving downstream to the RIN generating

[144] See https://www.epa.gov/compliance/next-generation-compliance

parties in a manner that is verifiable by independent third parties. Additionally, to address concerns over the burden, the regulations allow biogas producers of any size to hire third parties that provide compliance services such as facilitating report submissions to EPA.

Comment:

One commenter said that EPA does not address confidential business claims of the RNG producer and RNG RIN separator and, as such, EPA must preserve the ability of producers to claim any of the information required as CBI.

Response:

EPA will follow the procedures outlined in 40 CFR part 2 and 80.1402 regarding the treatment of information claimed as CBI.

Comment:

One commenter said that EPA should not require parties to submit emissions-related information because these additional requirements do not provide any additional certainty to the integrity of the RINs and place additional burdens on the biogas producers. The commenter also noted that this information is already being tracked by the air permitting agency at the state or federal level.

One commenter said: "No other biofuels or parties are required to submit this information under the RFS program, indicating that it is not needed to fulfill the agency's obligations under set. EPA has access to emissions information through the GHG reporting obligations, other air programs, and the NPDES permit program. Further, nothing in the statute indicates that Congress sought to regulate air or water emissions. This information is not needed to establish compliance with the RFS requirements. Finally, it is unclear why this information needs to be included with the registration. A facility's ability to generate RINs is wholly unrelated to emissions data. As the statute makes clear, the RFS program is not intended to regulate emissions. See, e.g., 42 U.S.C. § 7545(o)(12).

At a minimum, EPA should make clear that no new testing or monitoring would be required for any of the pollutants listed. EPA also should clarify that this applies only to any reports that may already be required under state or federal law and not any information on emissions that the facility may have."

Response:

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking. To the extent the comments relate to emission reporting requirements for biogas more broadly, we are also not finalizing these requirements in this rulemaking.

Comment:

One commenter stated that requiring all parties involved in a RINs transaction to establish an EMTS account for reporting requirements will be problematic, since many parties are ill-equipped to manage the proposed establishment of an EMTS account and the necessary reporting it would require. The commenter recommended instead signing of notarized affidavits attesting to RNG use.

Response:

We understand the commenter's concerns about minimizing reporting burden on industry. However, EMTS has served to record all RIN transactions and is a platform that can efficiently handle reporting of biogas batches and other information required to be reported in this action. In addition, this information will serve as an important mechanism for verification of RINs under the RFS QAP, annual audits under the attest engagement provision, and EPA's ability to implement and oversee the program. Given this, we are finalizing this reporting requirement as proposed. Biogas producers who choose to participate in the RFS program and need additional help meeting compliance requirements can engage with third-party providers for submitting registration updates and compliance reporting including with EMTS transactions.

10.9 Product Transfer Documents

Comment:

One commenter requested clarification on when PTDs are required. Stating that PTDs should only be required when confirming compliance with the RFS and not for biogas and RNG outside of the program.

Response:

The biogas regulatory reform provisions only apply to biogas and RNG that is used to produce renewable fuels and generate RINs under the RFS program. To clarify our intent, we are finalizing modifications to the proposed definition of biogas to clarify that in order to be biogas under our regulatory provisions, the biogas must have been produced under an EPA-approved pathway for RIN generation and RNG must be made from such biogas. Parties that elect to produce biogas outside of an EPA-approved pathway are not subject to the RFS program and would not specifically be subject to PTD requirements as suggested by the commenter. We reinforce that such biogas, and any RNG, biointermediate, or renewable fuel produced from such biogas, would be ineligible for the generation of RINs under the RFS program.

Comment:

One commenter said that EPA should not require that biogas PTDs or registration information indicate the intended ultimate use of biogas and that biogas producers should only need to indicate the intended next use.

Response:

In the NPRM, we did not intend that biogas PTDs or registrations indicate the intended ultimate use beyond RNG. In the proposed 80.160(b)(3)(iii), we indicated the language for biogas used to produce RNG. The biogas producer does not need to indicate how the RNG will be used. In the proposed 80.145(c)(3), we provided examples of the use cases that biogas producers can specify at registration, one of them being RNG. We are intending to finalize these provisions which do not require identifying the ultimate use of biogas and believe this addresses the commenter's concerns.

Comment:

One commenter said that EPA appears to require PTDs any time biogas is transferred, even if no RINs are involved.

First, we note that there are no RINs for biogas under the biogas regulatory reform provisions. Second, in order for RNG producers and biogas closed distribution system generators are able to validly generate RINs, the receiver of biogas must know the D-code, verification status, and feedstock information for the biogas. This information is transferred from the biogas producer to the downstream party/ies via a PTD. Given the need to transfer this information, we are finalizing that biogas producers transfer PTD information as proposed.

Comment:

One commenter said that EPA appears to require PTDs any time RNG is transferred, even if no RINs are involved, and that proposed § 80.160(c) appears to require PTDs whenever custody of RNG is transferred, while proposed revised § 80.1453(a)(12)(viii) only references PTDs for transfer of RNG "for which RINs were generated."

Response:

We did not intend for these provisions to apply to all transfers of custody of RNG, which is why we noted in the proposed regulations at 40 CFR 80.160(c) that these provisions only applied "[w]henever custody of RNG is transferred ***prior to injection into a pipeline interconnect*** (e.g., via truck)" (emphasis added). Most custody transfers occur after injection into a pipeline interconnect and would therefore not be subject to the proposed PTD requirement at 40 CFR 80.160(c).

We proposed and are finalizing PTD requirements for custody transfers when RNG is produced at a RNG production facility and not directly injected into the natural gas commercial pipeline system (e.g., because the RNG was transported via truck from the production facility to a pipeline interconnect). As explained in Preamble Section X.H.3, these PTD requirements are necessary to ensure that RINs are generated from RNG produced under an EPA approved pathway and create a paper trail that will ensure that the RNG was actually injected into the natural gas commercial pipeline system.

The commenter correctly identified that the PTD language at 40 CFR 80.1453(a)(12)(viii) applies to transfers of title of RNG. We intended these PTD requirements to be separate because 40 CFR 80.1453(a) only applies to transfers of title.

We do not believe any changes are needed to clarify our intent, therefore, we are finalizing as proposed the PTD requirements for transfers of RNG.

Comment:

One commenter says "EPA should clarify that PTDs are only required for purposes of confirming compliance with the RFS and not require PTDs for biogas and RNG not sold for purposes of producing a renewable fuel under the program. Requiring RINs be generated for any and all RNG produced is inconsistent with how EPA is treating all other biofuels."

Response:

Under the proposal, PTDs would only be required for purposes of confirming compliance with the RFS and not required for biogas and RNG not sold for purposes of producing a renewable fuel under the program. This is consistent with how other renewable fuels are treated under the program. We have modified the definitions of biogas to clarify that only biogas produced under an approved pathway (and thus part of the RFS program) and, by extension, RNG and biogas-derived renewable fuels produced from such biogas are subject to RFS requirements. We note that gas not produced under an approved pathway would not be eligible for RIN generation.

10.10 Recordkeeping

Comment:

One commenter said that EPA failed to provide an explanation for the basis for proposed recordkeeping requirements at § 80.155(b)(3) and (4). The commenter said that the former provisions are too broad and recommends EPA remove this provision until it can provide an explanation and give the public an opportunity to comment.

Response:

As stated in the NPRM, we proposed modifying regulatory requirements for renewable CNG/LNG pathways to ensure the program can be effectively overseen and that biogas is not double counted.[145] The proposes regulations at 40 CFR 80.155(b)(3) and (4) requires biogas producers to keep documentation of composition, cleanup, and heating usage, which are all necessary to ensure RINs are generated for fuel produced from renewable biomass. Given that we proposed these provisions and explained why they are necessary in the NPRM, we have already given the public the opportunity to comment on these provisions. Below we describe these requirements:

- The composition of the biogas determines its heating content which is needed to determine the maximum number of RINs that should be able to be generated for that volume of biogas. It also may be able to indicate addition of fossil natural gas to the biogas stream, indicating fraudulent activity. This information is necessary to ensure RINs are properly generated from renewable biomass.
- The cleanup involves the technology used to remove trace impurities, particles, and water vapor, including replacement of adsorbent, energy usage, filter cleanings, and other documents. This information is necessary to show that amount of biogas reported to EPA is in accordance with the facility’s operation.
- Documentation related to the process heat source and amount is necessary to avoid situations where biogas is used as process heat and where fossil natural gas is injected into the pipeline and is claimed to be RNG.

It is our understanding that these records are typically generated as part of customary business practice. The commenter has not suggested an alternative or narrower approach to the requirements under 40 CFR 80.155(b)(3) and (4) that could ensure that parties generating and verifying RINs have the information necessary to do so. We are therefore finalizing 40 CFR 80.155(b)(3) and (4) as proposed.

Comment:

One commenter stated that EPA failed to provide a basis for multiple provisions in the proposed recordkeeping regulations at 40 CFR 80.155(e) and the commenter recommends EPA remove these provisions until it can provide an explanation and give the public an opportunity to

[145] 87 FR 80693.

meaningfully comment, including providing proposed revised regulatory language. Specific provisions are listed below:

- Proposed 40 CFR 80.155(e)(4) would require RNG producers to retain a copy of Compliance Certification under Title V of the Clean Air Act. The commenter mentions that the RFS is not targeted at regulating emissions.
- Proposed 40 CFR 80.155(e)(6) would require RNG producers to retain records related to process heat source for the production process. The commenter notes that none of the pathways dictate the type of process heat used with respect to biogas upgrading process.
- Proposed 40 CFR 80.155(e)(9) would require RNG producers to retain records related to compliance with proposed § 80.140(b)(7) related to pipeline interconnection and allocation of RINs.

Response:

EPA explained the reasoning for these provisions in the NPRM which said that the biogas regulatory reform provisions are necessary to ensure adequate oversight and avoidance of double-counting when biogas can be used, especially if used for more than just CNG/LNG.[146] The recordkeeping provisions the commenter mentions are necessary to oversee and the program, including identifying and enforcing on violations. Given that we proposed these provisions and explained why they are necessary in the NPRM, we have already given the public the opportunity to comment on these provisions. Below we describe the provisions individually.

If a facility generates significantly more RNG than allowed under their Compliance Certification, this may indicate that fossil natural gas is being input into the system for which RINs are generated. Requiring the producer to keep records of the Compliance Certification (in proposed 40 CFR 80.155(e)(4)) allows EPA to more easily assess whether fraudulent activity was likely to have occurred. Using these types of documents to help with compliance is not new for the RFS, and we previously have required it for all renewable fuel producers to submit Compliance Certifications pursuant to 40 CFR 80.1450(b)(1)(v)(A).

Knowing the source of process heat is necessary to understand how much RNG is injected on the pipeline. For example, this information is necessary to detect cases in which a facility uses biogas for process heat but does not disclose that and instead injects fossil natural gas onto the pipeline, claiming it is RNG and generating RINs on this. Given the fungibility of biogas and fossil natural gas in this application, we believe this information is necessary to discourage and enforce upon such fraudulent behavior. The commenter does not explain how having the producer keep records of their process heat usage (proposed to be required under 40 CFR 80.155(e)(6)) would not be central to preventing this type of fraudulent activity in the program.

The provisions in the proposed 40 CFR 80.155(e)(9) require RNG producers to keep records showing that they generated the proper number of RINs based on the amount of RNG injected onto the pipeline. This is necessary to effectively determine if fraudulent activity has occurred. The commenter mentions concern that RNG producers may not be able to obtain such information. If this were the case, they would not be able to determine the correct number of

[146] 87 FR 80692-80693.

RINs according to 40 CFR 80.140(b)(7). Given this information is necessary to generate RINs, we believe parties would already have access to this information and it would not pose a significant barrier to participating in RFS.

Comment:

One commenter stated that EPA failed to provide a basis for multiple provisions in the proposed recordkeeping regulations 40 CFR 80.155(e) and the commenter recommends EPA remove these provisions until it can provide an explanation and give the public an opportunity to meaningfully comment, including providing proposed revised regulatory language. Specific provisions are listed below:

- Proposed 40 CFR 80.155(e)(10) would require RNG producers to retain summaries comparing raw biogas to treated biogas. The commenter notes "it is generally unclear and to the extent it seeks to require new testing."
- Proposed 40 CFR 80.155(e)(11) would require RNG producers to retain documents supporting the amount of methane and other gases released into the atmosphere at the facility. The commenter states that the RFS program is not intended to regulate air emissions and that the term 'support' is unclear.

Response:

Given that we proposed these provisions and explained why they are necessary, we have already given the public the opportunity to comment on these provisions, including on the proposed regulatory language.

Our intent in proposed 40 CFR 80.155(e)(10) was to ensure that producers keep records of the summary tables required in 3-year engineering review updates specified in proposed 40 CFR 80.145(f)(7)(iv). This requirement is not meant to require new testing, but rather reflect the testing that is part of engineering reviews for RNG producers. EPA has required that records of all sampling, testing, and measurement necessary to demonstrate that fuels and renewable fuels are produced consistent with CAA and EPA regulatory requirements. EPA explained the reasoning for these provisions in the NPRM, which said that the biogas regulatory reform provisions are necessary to ensure that the RNG producer is capable of producing RNG that can be used as transportation fuel consistent with CAA and EPA regulatory requirements. The recordkeeping provisions the commenter mentions are necessary to oversee the program, including identifying and enforcing on violations, as described below.

Likewise, our intent in proposed 40 CFR 80.155(e)(11) was to ensure producers keep records related to air emission information in proposed 40 CFR 80.80.145(i). However, because we are not finalizing the proposed submission of air and water emissions data in this rulemaking, we are also not finalizing the requirement to keep records related to submission of such information.

We note, however, that because we already require recordkeeping of registration records at proposed 40 CFR 80.155(a)(1)(ii), we see the requirements that the commenter highlighted in 40 CFR 80.155(e)(10) as duplicative and have removed the proposed 40 CFR 80.155(e)(10).

However, the regulations at 40 CFR 80.145(a)(1)(ii) still require that parties keep copies of the summaries of test results related to the sampling and testing of biogas and RNG at 3-year registration updates since it is related to the information required at registration.

Comment:

One commenter urged EPA to maintain consistency with existing regulations allowing for the continuance of quarterly affidavits to attest for involvement and accuracy of data related to renewable CNG/LNG use instead of requiring all parties involved, including those who may not be equipped to meet the administrative deadlines, to create an EMTS account for reporting.

Response:

While we are maintaining provisions that will allow for the use of affidavits for RNG RIN separators to support the separation of RINs for RNG (see 40 CFR 80.125(d)(2)), the creation of these affidavits is insufficient by itself to ensure that RNG is used as transportation fuel and ensure that RNG is not double counted. As described in Preamble Section IX.D, we are leveraging RNG RIN assignment and separation as a mechanism to track the movement of RNG through the natural gas commercial distribution system from the point that the RNG is injected to the point that the RNG is withdrawn and demonstrated to have been used as transportation fuel. Because a RIN can only be separated once, by requiring that the RNG RIN separator register and separate RINs in EMTS, we can help avoid the double counting of RNG while tracking the movement of the RNG via the RIN in EMTS. Under the previous biogas provisions, we have concerns that parties may rely on the same affidavit for RIN generation resulting in double counting. Under biogas regulatory reform, this would not be possible.

Furthermore, as we noted in Preamble Section IX.A.4, such a tracking mechanism is needed to allow for the use of biogas as a biointermediate and RNG as a feedstock while maintaining our ability to oversee the program. We believe our concerns with double counting will be exacerbated with the allowance of biogas/RNG to be used in a form other than renewable CNG/LNG. For these reasons, we are finalizing our approach to having the RNG RIN separator separate the RINs in EMTS instead of relying solely upon the creation of a quarterly affidavit as suggested by the commenter.

10.11 Testing and Measurement Requirements

Comment:

Several commenters stated that EPA should focus on setting minimum accuracy requirements instead of stating specific technology that should be used for measuring flow and methane content.

Response:

Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques.[147] Given the concern that other standard or methods may be more accurate as technology develops, we are allowing for alternative measurement protocols to be submitted at registration and specifying that the biogas or RNG producer supply sufficient documentation showing the accuracy and precision of the alternative measurement protocol. We believe this approach balances the requirements in the NTTAA and stakeholder concerns.

Comment:

Several commenters recommended allowing other devices for measurement of methane content of biogas or RNG, such as non-dispersive infrared analyzers (NDIR). Commenters that mention NDIR state that this device is more prevalent, reliable, and accurate than gas chromatography.

Multiple commenters state that the ASTM method cited in the NPRM is designed for natural gas and not for biogas.

Response:

Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques.[148] The use of other techniques mentioned by the commenters depends on whether a standard meets the requirements. Commenters did not suggest standards for the alternative measurement devices for methane devices that they recommended EPA allow, and EPA did not find a standard for that device.

The commenters also provided no accuracy or precision measurements to support that the alternative suggested meters were as accurate as the meters utilizing the standard in the NPRM.

The standard that EPA proposed for measuring methane content through in-line GC is for high methane content gaseous fuels. Biogas has a high methane content given that methane is often either the most common or second most common component of biogas. The commenters did not supply any specific reason why the standard would not apply to biogas, nor did they provide an

[147] 15 CFR 287.4(f).
[148] 15 CFR 287.4(f).

alternative standard. Given that the standard still appears to apply to biogas and the commenters presented no information why this would not be the case, we are finalizing as proposed the requirement for inline-GC meters using ASTM-D7164-21.

Nevertheless, as discussed in the first response in this subsection, we are finalizing an allowance for alternative measurement protocols that should address some of the commenters' concerns.

Comment:

Several commenters recommended allowing a broader range of flow measurement devices. Some specifically mentioned thermal mass flow devices. Some commenters asked EPA to accept all flow devices that meet manufacturers specifications for the specific conditions. One commenter states that EPA provided no analysis as to whether the flow measurement devices are appropriate, available or used by the industry.

Response:

Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques.[149] The use of other techniques mentioned by the commenters depends on whether a standard meets the requirements. In their written comments, commenters did not provide standards for the alternative measurement devices that they recommended EPA allow. Upon searching for standards, we did find one standard for thermal mass flow measurement devices which appears to be sufficient, and we have added the standard specifying thermal mass flow devices as an allowed measurement method under 40 CFR 80.155(a).

In addition, as discussed in the first response in this subsection, we are finalizing an allowance for alternative measurement protocols that should address some of the commenters' concerns.

Comment:

Multiple commenters recommended allowing for the facility to maintain the equipment according to manufacturers' operating procedures instead of requiring a standard method.

Other commenters suggested EPA require biogas and RNG producers to have sufficient documentation to support volume measurements which they can provide to EPA.

Response:

Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies are directed to give preference to standardized measurement techniques when available.[150] Given this requirement, if there is a standard that applies in this situation, we specify that those measurement techniques may be used. Since manufacturers can change their operating procedures without going through the standards process in ways that can negatively

[149] 15 CFR 287.4(f).
[150] 15 CFR 287.4(f).

impact the meter's accuracy, we are concerned that manufacturers that publish less stringent operating procedures may be preferred, even if these requirements reduce the accuracy of the meter. Given this concern, we are not specifying in the regulations that following a manufacturer's operating procedures is sufficient to meet the metering requirements.

The commenters were not clear about what records they thought would be sufficient to support the volume measurements. In order to make compliance clear for regulated parties, we are finalizing an approval process at registration so that parties can demonstrate that an alternative measurement method is sufficient. We believe this option provides increased flexibility that the commenters asked for while also providing clarity that they are compliant with the regulatory requirements.

Comment:

One commenter recommended that financial transactional metering should not be required to meet all the metering requirements in the NPRM if specific independence requirements are met. The commenter stated that taking this approach would be similar to California's LCFS program and recommended the following language:

> Pipeline meters used for the continuous measurement of RNG which is injected or withdrawn from the commercial pipeline system are exempt from the specifications and requirements in Proposed Rule § 80.165 if the RNG Producer and RIN Separator, and any supply chain entities who hold title to the RNG in between injection and withdrawal, do not have any common owners and are not owned by subsidiaries or affiliates of the same company.
>
> Pipeline meters for the injection or withdrawal of RNG from the commercial pipeline system where the RNG Producer and RIN Separator do have common owners or are owned by subsidiaries or affiliates of the same company are exempt from the specifications and requirements in Proposed Rule § 80.165 if: (1) the financial transaction meter is also used by other companies that do not share common ownership with the fuel supplier; or (2) the financial transaction meter is operated by a third party.

Response:

While we agree that independence requirements should reduce the risk of the meters giving inaccurate values, the commenter did not sufficiently explain why these provisions are as good if not better than requiring standards to be met. Further, as discussed in the first response in this subsection, we also are finalizing the proposed provision allowing alternative measurement approvals, which we think should address some of the commenter's concerns. Given the addition of an alternative option, we do not believe it is necessary to create a separate allowance for financial transaction meters in addition to allowing alternative measurement protocols.

Comment:

One commenter stated that EPA requirements should not conflict with those that are already required under state or other federal law, which may be incorporated into existing pipeline specifications.

Response:

The commenters did not provide an example of how the requirements could conflict with state or federal laws. We did not find an example of a law that prohibited installing an additional measurement device which would apply to biogas or RNG production facilities. Furthermore, it is unclear how the commenter would like the regulations to be modified to avoid conflicting with state or federal law.

Comment:

One commenter stated that biogas producers supplying an entity that is required to comply with the metering requirements should not need to install the equipment specified under proposed 40 CFR 80.165(a). Instead, it should have online monitoring equipment of sufficient accuracy and frequency for mass balance. Another commenter stated that metering should not be required if there is no addition of non-renewable commodities.

Response:

As stated in the NPRM, we proposed modifying regulatory requirements for renewable CNG/LNG pathways to ensure the program can be effectively overseen and that biogas is not double counted.[151] Given the potential for introducing non-renewable natural gas into an RNG producing facility and fraudulently counting it as RNG, it is important to know how much biogas is entering that facility and the energy content of that biogas. Without this information, it would be more difficult to identify fraudulent activity under the program. The commenters did not adequately describe how the regulations would provide for the detection of this type of behavior if measurement of biogas was not conducted. Given that this requirement helps deter and catch fraudulent activity, we are finalizing that biogas should be measured before being upgraded to RNG.

The commenter did not describe how online monitoring equipment is of sufficient accuracy and frequency for mass balance. Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques.[152] In addition to standards for measurement, we are finalizing an option for approval at registration if those standards cannot be met.

[151] 87 FR 80693.
[152] 15 CFR 287.4(f).

Comment:

Several commenters disagree that biogas producers already have the measurement equipment proposed to be required in the NPRM.

Response:

In the NPRM we stated "We do not believe these proposed requirements would impose any additional burden on currently registered parties as the proposed requirements are in line with existing guidance and we believe all current registrants for biogas have indicated that they comply through their registrations."[153] We also sought comment on these provisions and, based on the comments, were made aware that some parties use other measurement devices that do not comply with our existing guidance and thus, the standards that we proposed. Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques,[154] so even though these requirements may result in parties having to install devices covered by a standard, we are directed to give preference to these requirements by the NTTAA. In addition, we have allowed for alternative measurement protocols that should reduce the burden of measurement for currently registered parties.

Comment:

One commenter agrees with the NPRM requirement that RNG producers should have measurement equipment.

Response:

We appreciate the comment and have finalized this requirement.

Comment:

One commenter states that biogas producers should not need to measure at the outlet of each digester. The commenter quotes the proposed rule as "Proposed Rule § 80.105(f) requires that biogas producers 'continuously measure the volume of biogas … from each digester … prior to mixing with any other biogas.'" The commenter states that for a digester operating on the same feedstock, this requirement is burdensome and unnecessary. The commenter specifically mentions biogas digesters located in series.

The commenter proposed the following requirements:

- Digesters that are operated in series do not need separate metering provided the installed meters quantify all biogas produced from all digesters in series.

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[153] 87 FR 80676.
[154] 15 CFR 287.4(f).

- Batch digesters that are simultaneously fed the same feedstock or feedstocks do not need separate metering provided that the installed meters quantify all biogas produced from all digesters operated in this way.

Response:

The commenter does not describe what they mean by 'digesters in series,' which could involve the digestate from one digester going into a second digester, the biogas from one digester going into another, or both the digestate and biogas going to a second digester. These different interpretations have different compliance and implementation concerns that would need to be addressed separately. For example, having a single measurement for two digesters where the biogas is pumped from one digester to another and where the digesters obtain different feedstocks would not be able to calculate how much biogas corresponds to each D-code. Given the multiple interpretations of the comment and varied compliance concerns, we are not including a special allowance for 'digesters in series.'

We did not propose nor are we finalizing that measurement is required at the output of each digester. The regulatory section the commenter mentioned in the NPRM states: "A biogas producer must continuously measure the volume of biogas, in Btu, from each digester subject to § 80.1426(f)(3)(vi) prior to mixing with any other biogas." The commenter removed 'subject to § 80.1426(f)(3)(vi)' from their quote, which specified that this provision only applies to situations in which multiple feedstocks are processed simultaneously and would result in renewable fuels with different D-codes, so the proposed provision would apply to only the fraction of digesters in the program that accept multiple feedstocks of different D-codes. The comment does not appear to acknowledge this limitation but rather seems to reference all digesters, and not just those subject to 40 CFR 80.1426(f)(3)(vi). We believe our proposal addresses the concern of the commenter and are finalizing the requirement as proposed.

Comment:

Multiple commenters stated the continuous measurement requirements are too onerous based on the volume of data that must be stored and transferred to auditors. Some commenters mentioned the requirements for all devices and some commenters focused only on the flow meters.

One commenter recommended recording data at one-minute intervals, mentioning that this frequency is currently used and can account for startup, shutdown, and changes in flow.

Response:

As discussed in Preamble Section XI.A, one of the aims of biogas regulatory reform is to have a program that can be effectively overseen when biogas is used for multiple types of fuel. Continuous measurement is a crucial part of overseeing an effective program, especially when there is concern that non-qualifying feedstocks may be added. Most commenters did not provide an alternative frequency for the continuous measurement provisions. While the commenter that stated that one minute time intervals can account for startup, shutdown and changes in flow, they did not provide any data to support that claim. The commenter also did not make clear whether this applied to the on-line gas chromatogram or not.

In order to balance the need to obtain accurate measurements and the data storage and transfer concerns, we are allowing for flow meters that measure no less frequent than every 6 seconds to be able to total the flow on a minute basis and record that data. We believe this addresses commenters' concerns around storing and transferring meter data.

Comment:

One commenter stated that the proposed timeframe would not allow sufficient time for installation.

Response:

As discussed in Preamble Section IX.F, we are delaying the implementation date of biogas regulatory reform by 6 and 12 months (based on whether the facilities were previously registered) from what was proposed. We believe this, in addition to the alternative measurement protocol allowance, will allow parties to obtain the necessary equipment by the time they need to come into compliance with the biogas regulatory reform provisions.

Comment:

One commenter stated that allowing facilities to seek alternative measurements approvals would likely delay registration and RIN generation.

Response:

We agree that alternative measurement approval would require additional analysis when reviewing these applications, which may take those applications additional time to process. However, it was unclear whether the commenter was therefore suggesting we not permit alternative measurement protocols. Given that alternatives may be warranted in some circumstances, EPA is finalizing the regulations to allow alternative measurement protocols.

Comment:

One commenter stated that insufficient time for public comment prevented them from definitively determining the appropriateness of the continuous measurements proposed by EPA and that EPA should provide sufficient information to the public in order to determine if EPA's proposal is reasonable, as required by the Clean Air Act.

Response:

We have addressed comments related to the length of the comment period for this action in RTC Section 12.3.

In addition, as discussed in the first response in this section, we are finalizing allowing alternative measurement protocols, which should resolve some of the concerns of the commenters.

Comment:

EPA should make clear that any alternative sampling protocol approved or required by a state or other federal authority or that is incorporated into a pipeline specification will be automatically approved.

Response:

We did not intend in our proposal to automatically approve any alternative sampling protocol which has already been approved, which is required by a state or other federal authority, or which that is incorporated into a pipeline specification. Different regulatory programs have different objectives and what is sufficient for one program may not be appropriate for a different program. For example, a program focused on safety might have measurement requirements that are less accurate than those focused on accurate accounting of heating values. In addition, differences between facility biogas quality may make a protocol applicable for one facility in the RFS and not for another facility. We believe the standards methods specified in 40 CFR 80.155 should be generally applicable and we would approve those. Given this, we are not allowing for compliance with any federal, state of pipeline company requirements for an alternative measurement protocol to provide automatic approval under RFS. Parties may, however, request that EPA approve an alternative sampling protocol as part of registration.

Comment:

One commenter requests that EPA clarify whether and how biogas should be measured under 40 CFR 80.130(f)(1).

Response:

We recognize that including biogas in the proposed 40 CFR 80.130(f)(1) was confusing. We removed biogas from this clause to clarify that only natural gas should be measured.

Comment:

Multiple commenters opposed the provisions related to measurement requirements for trucked RNG. The commenter highlighted that the proposed regulations would require in-line GC meters at both the loading point and unloading points for trucked RNG. The commenter said that while they agreed that pipeline interconnects receiving RNG should be metered for flow and energy content measurement, the commenter took exception to the requirement that all trucked RNG requires an in-line GC at the unloading point when there are alternative energy content measurement instruments.

Response:

The commenter asserts that if measurement is conducted upon truck loading that it does not need to be done with the standard device upon truck unloading. However, EPA is concerned that an operator may try to add natural gas during transit and pass it off as RNG. This situation is further complicated when multiple facilities unload RNG at a single interconnect where multiple facilities inject. The addition of natural gas on a truck can make up for potential system loses at other facilities or at the interconnect for gas that is flared because it is not within specifications. Given this, we still believe that accurate measurement at both ends of trucked RNG is necessary for program oversight and are finalizing this requirement as proposed.

While the comment suggests that alternative energy content measurement instruments may be sufficient, it does not provide any specific alternative measurement devices for EPA to consider. Federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques. The appropriateness of an alternative measurement technique depends on whether a standard meets the requirements. Therefore, while we are finalizing the proposed measurement requirements that apply to truced RNG, we are also finalizing an option for approval for an alternative measurement protocol, which we believe will address some of the commenter's concerns.

Comment:

One commenter recommended a change to § 80.105(f)(1)(ii) and (iii) to require volume and composition to be measured separately.

Response:

Parties need to meet the requirement to measure biogas in Btu by obtaining both a volumetric or mass-based measurement and a composition measurement, using the standards specified in § 80.155(a). Parties can then combine both these measurements to determine the number of Btus. The commenter did not describe why the regulations need to explicitly state volume and composition separately, given that these are specified in § 80.155.

Comment:

Multiple commenters questioned EPA's need for expensive new metering requirements due to lack of RNG fraud and detailed QAP review of these transactions.

Response:

Metering is the basis for catching any fraud that may be occurring, as well as for the QAP providers reviewing documents. Without accurate and standardized metering, we fraud would be hard to detect. Further, even if there is not any fraud, without proper metering an improper number of RINs would be generated.

Comment:

One commenter questioned the need for the RNG producer to sample and test representative samples of both the biogas used to produce RNG and the RNG at least once per calendar year. The commenter pointed out that the RNG producer already works with the pipeline to ensure that the RNG meets their pipeline specifications, and having to retest both the inlet gas and the finished biogas annually seems like an unnecessary burden, especially since these gas quality test results are provided as part of the initial registration.

Response:

We have removed the requirement that annual sampling and testing is required. We are finalizing a requirement that the sampling and testing be provided in the 3-year update. We believe this reduces the burden on the stakeholder while balancing the need to show that the RNG complies with the pipeline specifications.

Comment:

One commenter was not able to confirm whether the specified flowmeter requirements were reasonable, as they could not easily access the prescribed standards, which only appeared to be available online at a cost. Technical specifications supplied with meters they were familiar with did not explicitly indicate whether they complied with the prescribed standards.

Response:

In the NPRM we specified the standards we were considering.[155] These standards are for equipment that is typically used within the natural gas industry, and we therefore expected parties to be familiar with these standards. From the comments received, it appears that parties knew of the types of devices specified in the standards, since multiple parties commented on the applicability of online GC meters and orifice meters for biogas and RNG applications. Because it is clear that industry participants are familiar with the devices and we believe those devices and the associated standards are the best way of measuring and monitoring biogas flows and volumes, we are finalizing use of the standards as proposed. In addition, for entities looking to invest millions of dollars to produce RNG (or looking to represent those entities), we believe the marginal cost to purchase the standards is low enough to satisfy the requirements for being reasonably available.

We note that while we are specifying that parties may use industry standards consistent with our responsibilities under NTTAA, under the biogas regulatory reform provisions, parties may request that EPA approve an alternative sampling protocol as part of registration.

It is also worth highlighting that there is no requirement that these parties participate in the RFS program. Revenue from RINs under the RFS program can provide them with an additional

[155] 87 FR 80718.

source of income to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

Comment:

One commenter states, “while EPA indicates the specifications listed have been provided in registrations and they believe them to be accurate. That analysis falls short. Testing and monitoring requirements for pipeline specifications are not universal. Many pipeline specifications do not require specific testing methods or parties may have agreed to different testing methods. It is unclear what assessment EPA has done to ensure these are appropriate and accepted industry-wide or why EPA is the proper arbiter of the proper testing methodology or the monitoring requirements. FERC is the federal agency that addresses pipelines. EPA could simply make clear that following any pipeline specifications or state/federal law requirements should be sufficient to show the pipeline specifications are met.”

Response:

The requirements that list methods for measuring certain components of biogas and RNG are for compliance with our program and may differ from the test methods used by the pipeline operator. The purposes of our testing are to show that the RNG complies with the pipeline specification for RIN generation and to ensure cleaning of biogas is occuring, whereas the purpose of testing by the pipeline operator may be different. We also require testing of components which may not be specified by the pipeline operator.

As discussed in the NPRM, we proposed testing for compounds mentioned in our biogas guidance document on biogas and chose methods commonly used by market participants to comply with the guidance.[156]

[156] 87 FR 80675-80676

10.12 RFS QAP Under Biogas Regulatory Reform

Comment:

Multiple commenters recommended QAP be made mandatory instead of implementing biogas regulatory reform or that parties that participate in QAP be exempt from biogas regulatory reform. Commenters state that QAP provides EPA with sufficient ability to deter potential fraudulent RIN production or double counting. Multiple commenters said that the documentation required under QAP is comprehensive and independent auditors conduct extensive verification from generation to fuel dispensing to ensure that only qualified RNG-to-CNG generates RINs.

One commenter states that EPA does not indicate that the QAP process provides insufficient oversight. The commenter also states that EPA indicates it could finalize the eRIN program without the biogas regulatory reforms if it imposes QAP requirements.

One commenter urges EPA to require participation in the QAP program until a separate rulemaking dedicated to biogas regulatory reform provisions can be completed.

Response:

In the NPRM we stated, "should we not finalize biogas regulatory reform, we intend to require all participants in eRINs and RNG chain participate in the RFS QAP program to help avoid the generation of fraudulent and invalid RINs."[157] We agree with commenters that QAP does provide some degree of oversight that can avoid some generation of fraudulent and invalid RINs. However, we do not believe mandatory QAP is a replacement for regulations that ensure proper oversight and compliance, as discussed in Preamble Section IX.J, in this response below, and in subsequent responses in this subsection.

QAP providers have information only for facilities which they QAP. They do not have access to contracts and sales information which exist with other parties. For example, a QAP provider may not know whether a CNG producer has contracts with other RNG producers and whether that CNG producer has inadvertently double-counted usage of RNG to multiple facilities. Biogas regulatory reform, by placing RNG information in EMTS, can prevent this type of double counting which the QAP program is not able to solve.

Additionally, while QAP assists with identifying some generation of fraudulent and invalid RINs, QAP does not resolve the oversight issues related to tracking volumes of biogas, RNG, and renewable CNG/LNG through a complicated contractual network, which, among other things, make it very difficult to detect fraud and therefore to oversee and enforce the program. Under the previous regulations, in order to be sure of any double-counting by a CNG producer, EPA would have to obtain records from every RNG producer, CNG producer, and LNG producer connected in the many-to-many contract network. By placing RNG information in

[157] 87 FR 80698 (December 30 2022).

EMTS, all the transactions are readily available in an accessible format for analysis. Mandatory QAP would not reduce the burden of enforcing on invalid or fraudulent RINs.

For these reasons and additional reasons listed in RTC Section 11.1, mandatory QAP is not a substitute for biogas regulatory reforms which are necessary to have a program which can prevent invalid or fraudulent RINs.

Comment:

One commenter said that EPA should provide flexibility to have different operations use different QAP providers. The commenter explained that it would likely be difficult and more costly if the same auditor must be used, which is particularly true under the RNG industry's view that more flexibility as far as uses for the biogas and RNG should be allowed.

Response:

As stated in the NPRM,[158] we believe the same QAP providers need to look at all the different parties in RIN generation/disposition chain to provide the level of assurance that is expected from the RFS QAP. In order to verify RINs, QAP auditors need to ensure that the information from all parties in the chain is correct and consistent. Having different QAP auditors look at different parts of the chain does not provide the level of oversight necessary to know that the information between parties in the chain is identical. The commenter does not explain how allowing different QAP providers would provide an adequate level of assurance.

Comment:

One commenter said that "Similar to attest engagements, EPA should clarify that QAP plans for RNG producers need only confirm that the facility is producing the biogas or RNG as listed in the registration and confirm measurements taken, but not check any pipeline specifications, air emissions and other information that may deviate from what is in the registration. Where EPA is seeking to request information that is not required to establish compliance with the RFS program, they should not impact the ability to generate RINs for fuel derived from the biogas or RNG."

Response:

We provide QAP providers with some flexibility to determine what attributes are necessary to verify RINs. If a QAP provider suggests a plan that includes checking pipeline specifications or other information, we would not prohibit the QAP provider from implementing such a check.

We discuss why pipeline specifications are necessary in RTC Sections 10.6 and 10.7.3, so we believe it is within the scope for QAP providers to check this information.

[158] 87 FR 80676.

To the extent the comments relate to emission reporting requirements for biogas more broadly, we are also not finalizing these requirements in this rulemaking.

Comment:

One commenter suggested that EPA should work with QAP auditors to create an approach that would allow for assigned D3 RNG RINs to be retroactively applied while awaiting QAP approval.

Response:

While we appreciate that QAP auditors may take time to conduct verification activities under the RFS QAP and this may result in the delay of the generation of verified D3 RNG RINs, we do not believe it is appropriate to promulgate a provision that would allow for retroactive verification of D3 RINs. Under the RFS QAP, it is the QAP auditor's responsibility to determine when RINs have been verified under an EPA-approved quality assurance plan, and it is often the case that prior to QAP auditor verification a RIN generator does not yet have the procedures in place that ultimately make a QAP auditor comfortable verifying RINs. This means that RINs generated prior to verification activities conducted by the QAP auditor are especially likely to not comport with QAP specifications. For this reason, we believe that allowing such an approach may result in pressures on the QAP auditor to verify RINs that were generated before the QAP audited conducted their verification activities, which may result in the verification of invalid RINs. In fact, this exact situation arose when EPA temporarily allowed a QAP auditor to retroactively verify over 70 million RINs, almost all of which turned out to be fraudulent.[159] Due to the increased opportunities for the verification of invalid or fraudulent RINs, we do not believe it appropriate to allow for the retrospective verification of RINs as suggested by the commenter.

[159] See Revised Final Determination and Settlement Agreement in Genscape, Inc. v. EPA 19-3705 (6th Cir.) available at: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/revised-final-determination-and-settlement.

10.13 Compliance and Enforcement Provisions and Attest Engagements

10.13.1 Prohibited Actions, Liability, and Invalid RINs

Comment:

One commenter opposes a scheme that places liability on all parties in the generation/disposition chain.

Response:

All parties in the generation/disposition are potentially liable, even parties in the generation/disposition chain that are not registered with EPA under the RFS program. This approach to liability has been used extensively in EPA fuels programs (e.g., the RFS program, gasoline, and diesel programs) where it is presumed that violations that occur at downstream locations (e.g., a retail station selling gasoline) were caused by all parties that produced, distributed, or carried the fuel. In our experience, fuel is more likely to be produced in compliance with the applicable requirements when all parties in the generation/disposition chain are potentially liable. Under biogas regulatory reform, RNG is mixed with other natural gas and is withdrawn on a book-and-claim basis. This system is especially susceptible to double counting and therefore violations. As a result, it is important that every party in the chain perform due diligence to ensure the entire generation/disposition chain is meeting the regulatory and statutory requirements. If upstream parties, such as RNG producers, are concerned about downstream noncompliance, they can take advantage of the affirmative defense provisions if the applicable criteria are met.

Comment:

One commenter asked that EPA confirm that actions could be taken by biogas and RNG producers to address the inadvertent double counting of RINs similar to the provisions in 40 CFR 80.1431(c) because the proposed regulations appear to limit remedial actions to certain parties.

Response:

Under the proposal, we intended for the provisions at 40 CFR 80.1431(c) to apply to all RIN generators, which would include RNG producers. To further clarify our intent, we are finalizing that 40 CFR 80.1431(c) applies to all RIN generators. It is unclear how the provisions at 40 CFR 80.1431(c) would apply to biogas because 40 CFR 80.1431(c) applies to the use of improperly generated RINs and under the previous biogas provisions and the new biogas regulatory reform provisions RINs are not generated for biogas. The regulations at 40 CFR 80.185 describes how parties will address situations where improperly produced biogas is found.

Comment:

One commenter stated that it is unclear what "non-qualifying volumes" means and requested that EPA make clear that it does not relate to deviations of any potentially applicable fuel quality specifications because the pipeline operator monitors the RNG placed into the pipeline.

Response:

We have revised the regulations to clarify that non-qualifying RNG volumes refer to volumes of RNG that does not meet the applicable requirements for such fuel under 40 CFR part 80. RNG that does not meet applicable fuel quality specifications prescribed by the pipeline operator may still qualify as RNG if the RNG meets the applicable requirements under 40 CFR part 80.

Comment:

One commenter asked EPA to clarify how the potentially invalid RIN provisions relate to the provisions on CBI with respect to self-reported information and stated that such information should remain confidential unless and until EPA takes enforcement action.

Response:

Sections 211(o)(2)(A)(i), 114(a), and 208(a) of the Clean Air Act give EPA the authority to require parties involved in the production or distribution of renewable fuel to maintain and report information necessary to confirm that renewable fuel meets the applicable regulatory requirements, including volume-related information associated with RNG. It is essential that parties in the RNG production/distribution chain—which are interconnected—know the correct amount of RNG that was produced and transferred and if any volumes have changed to confirm that the gas was produced from renewable biomass as required under the RFS program.

If parties in the RNG production/distribution chain are concerned that notifying other parties of potentially inaccurate volumes may reveal CBI, it is worth highlighting that there is no requirement that these parties participate in the RFS program. Revenue from RINs generated under the RFS program can provide them with an additional source of income to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

Finally, it is also worth noting that EPA determined in a recent rulemaking that information such as total quantity of fuel, information relating to exceedances of the fuel standards associated with the violation, and information relating to the generation, transfer, or use of credits or RINs, that are contained in an EPA determination that RINs are invalid does not constitute confidential business information. *See* 87 Fed. Reg. 39600, 39652 (July 1, 2022). Although this determination only applies to information that is reported to EPA and subsequently included in EPA determinations (*see* 40 CFR Part 2, Subpart B, which applies to the handling of CBI by EPA), EPA believes it is relevant to the commentor's concern regarding the sharing of volume-related information to other third parties prior to that information being reported to EPA.

Comment:

One commenter stated that EPA should allow for a change in designation of RNG use after RIN generation in the event of changed circumstances (e.g., excess production or intended customer shuts down operations for emergency), allowing any assigned RINs to be retired if the new designated use is not for transportation fuel. The commenter said that EPA should revise the liability provisions of 40 CFR 80.1460(a) to reflect this proposed change. Further, the commenter stated that EPA should clarify in the liability provisions that changes in use by a downstream party does not impose liability on the RNG producer.

Response:

The intent of our proposal was to ensure that if RNG is used for any purpose other than to produce renewable CNG/LNG, that any assigned RINs be retired because the RNG will no longer be used as a transportation fuel under the RFS program. To clarify this intent, we are finalizing language at 40 CFR 80.125(e) that states that "[a]ny party that uses RNG for a purpose other than to produce renewable CNG/LNG must retire any assigned RINs for the volume of RNG within 5 business days of such use of the RNG." We note that if the RIN is not retired within 5 business days per 40 CFR 80.125(e), the RIN is invalid and must be retired or replaced pursuant to 80.1434(a)(8) or (9), as applicable. In most instances for invalid RNG RINs, the RNG producer will be required to retire the invalid RINs—and will not need to retire like-kind RINs. The RINs associated with the RNG will not have been seperated yet because RINs associated with RNG cannot be separated until it is used to produce CNG/LNG and a party demonstrates that the CNG/LNG was used or dispensed as transportation fuel.

The commenter does not explain why the prohibited acts language at 40 CFR 80.1460 must be changed to accommodate RNG RIN generation. We proposed and are finalizing prohibited acts provisions in the new 40 CFR part 80, subpart E that will apply to RNG and RINs associated with RNG.

We note that we are finalizing as proposed that RNG producers are always liable for the validity of RINs that they generate (see 40 CFR 175(a)(3)). We do not believe it is appropriate to exempt RNG producers from cases where RINs may become invalid because, similar to renewable fuel producers, holding all parties liable increases compliance and enhances compliance oversight. For example, if an RNG producer learns that a downstream party did not use the RNG it sold for transportation purposes, it can elect not to sell RNG to that party in the future to avoid additional invalid RINs being generated.

Comment:

One commenter asked that parties be given more than five business days after identifying a potential violation or potential double counting to notify EPA.

Response:

Parties are required to notify other parties of potentially invalid RINs within five business days under the existing RFS program, and EPA is unaware of parties being unable to meet that deadline. If a company is unsure whether there are potential non-qualifying volumes or double counting, it can disclose the issue to EPA within the required five business days and if it later turns out that the volumes are accurate and qualifying, it can notify EPA that no further action is needed.

Comment:

One commenter said that EPA must provide time for the person identifying the violation to confirm it is a potential violation before notifying EPA rather than requiring notice to EPA within five business days, and that more than 30 days may be needed to submit a written report to EPA that demonstrates the applicable elements of the affirmative defense.

Response:

These requirements—i.e., that EPA must be given notice within five business days of discovery and that a written report demonstrating that the applicable elements of the affirmative defense have been met within 30 days of discovery—are identical to the affirmative defense provisions applicable to other renewable fuels at 40 CFR 80.1473, and EPA is unaware of parties being unable to meet those deadlines. If a company is unsure whether a potential issue is a violation, it can disclose the issue to EPA within the required five business days and if it later turns out not to be a violation, it can notify EPA that no further action is needed. Further, companies can always supplement their written responses, as necessary, after they have been timely submitted.

Comment:

One commenter requested that an affirmative defense be available to RNG producers for any action of others that are beyond the control of the RNG producer.

Response:

As discussed above, this approach would conflict with the liability scheme that EPA has used extensively in fuels programs (e.g., the RFS program, gasoline, and diesel programs) where it is presumed that violations that occur at downstream locations were caused by all parties that produced, distributed, or carried the fuel. In our experience, fuel is more likely to be produced in compliance with the applicable requirements when all parties in the generation/disposition chain are potentially liable. An affirmative defense is available to RNG producers, but only if all applicable criteria are met to establish the defense.

Comment:

One commenter requested that EPA clarify what is meant by the requirement that a company seeking to assert an affirmative defense have "no financial interest in the company that caused the violation" since the parties are likely to have contractual arrangements.

Response:

Financial interest, for purposes of establishing an affirmative defense, means an entity that owns or controls any portion of the other company.

Comment:

One commenter requested that EPA should remove the requirement that in order to establish an affirmative defense, the biogas or RNG producer must have conducted or arranged to be conducted a QAP that includes, at a minimum, a periodic sampling and testing program adequately designed to ensure that the biogas and/or RNG meets the applicable requirements to produce biogas or RNG, because EPA cannot disapprove a QAP plan retroactively.

Response:

We believe the commenter is misunderstanding our intent. In the proposal, we used the term "QAP" in the proposed 40 CFR 80.190(c)(1) and (d)(1) to stand for a quality assurance *program* put in place by a biogas or RNG producer that was designed to ensure that biogas or RNG, as applicable, met the applicable regulatory requirements. The commenter's suggestions seemed to apply to RFS quality assurance *plans* that are submitted and approved by independent third-party auditors. To clarify our intent and address the commenter's confusion, we have modified the language at 40 CFR 80.180 to distinguish the quality assurance program conducted by the producer versus the quality assurance plans conducted by independent third-party auditors.

The requirement that the quality assurance program include a periodic sampling and testing program adequately designed to ensure that the biogas and/or RNG meets the applicable requirements to establish an affirmative defense is necessary because it demonstrates that producers have taken reasonable steps to ensure they are producing biogas or RNG that is compliant. A crucial element to any such producer conducting a quality assurance program is the periodic sampling and testing of biogas or RNG, as applicable, to ensure that it meets applicable regulatory requirements. The commenter failed to explain how such an element was not necessary for the establishment of an affirmative defense. Furthermore, we believe that participation in the RFS QAP (conducted by independent third-party auditors) by itself is insufficient to establish an affirmative defense because we believe that biogas and RNG producers can do other things for their particular situation that would be necessary to ensure that their biogas and RNG, respectively, meets the applicable regulatory requirements. As such, we are finalizing as proposed that in order to establish an affirmative defense, biogas and RNG producers must conduct (or arrange to be conducted) a quality assurance program that includes periodic sampling and testing.

Comment:

One commenter recommended that participation in the quality assurance program be mandatory, particularly for eRINs, given the complexity of the program and risk of liability. However, should mandatory participation prove unfeasible, the commenter suggested that EPA clarify that any of the parties in the value chain that opt for quality assurance can qualify for affirmative defense.

Response:

The regulations already require biogas and RNG producers to participate in a QAP in order to be eligible for an affirmative defense. That is not the only requirement, however, as other requirements must be met for biogas and RNG producers to establish an affirmative defense, such as not causing the violation, not knowing or having reason to know the fuel was in violation, and notifying EPA within the requisite time frame. To the extent the comment relates to eRINs, we are not taking any final action on eRINs in this rulemaking.

10.13.2 Attest Engagements

Comment:

One commenter said requiring that attest engagements for biogas producers is unjustified.

Response:

Attest engagements are an important compliance mechanism for all types of regulated parties, including biogas producers, and EPA has used annual attest engagement requirements to ensure the integrity of credit programs under its fuel programs for nearly 30 years. Attest auditors routinely find errors or missing reports through the attest engagement process resulting in updated compliance report submissions and remedial actions that correct RIN transactions. Maintaining accurate registration, reporting and recordkeeping benefits all participants in the RIN marketplace by helping ensure data integrity. Because of the benefits, we are finalizing as proposed that biogas producers must undergo an annual attest engagement.

Comment:

One commenter stated that EPA should require the applicable RIN generator to obtain sufficient documents to conduct attest engagements instead of requiring biogas producers to have a separate attest engagement, since biogas and RNG producers are likely to share information on biogas production.

Response:

Having the biogas producer complete the attest engagement process provides important benefits that would be lost were we not to require they do so separately. As discussed in Preamble Section IX.K.2, annual attest engagements are important to ensuring that biogas, RNG, and RINs generated for biogas-derived renewable fuels and RNG meet the applicable regulatory requirements and help ensure the integrity of the RFS program. Additionally, attest auditors routinely find errors or missing reports through the attest engagement process resulting in updated compliance report submissions and remedial actions that correct RIN transactions further providing integrity to the RFS program. Using the attest audit process as a mechanism to maintain accurate records, registration and reporting is critical to ensuring that RINs are generated only on qualifying biogas in a manner consistent with CAA and EPA regulatory requirements. As discussed in Preamble Section IX, the focus of biogas regulatory reform is on the key parties that are best positioned to ensure that renewable fuel is produced from renewable biomass and used as transportation fuel consistent with the Clean Air Act. The biogas producer is the party that actually converts renewable biomass to biogas, and we believe that independent demonstration of compliance by biogas producers is critical to ensuring the validity of RINs generated for RNG or biogas-derived renewable fuels produced.

Comment:

One commenter requested that EPA clarify that attest auditors under proposed 40 CFR 80.175(a)(2) can be an internal auditor as specified in 40 CFR 1090.1800(b) and that EPA clarify any independence and conflict of interest requirements associated with this allowance.

Response:

We proposed and are finalizing as proposed that the applicable attest engagement procedures specified at 40 CFR 1090.1800 and 1090.1805 apply to the attest engagement provisions under 40 CFR part 80, subpart E. The applicable procedures at 40 CFR 1090.1800(b) includes the provision that allows for a certified internal auditor to conduct the attest engagement report as suggested by the commenter. As specified at 40 CFR 1090.1800(b)(2), attest auditors must meet the applicable independence requirements at 40 CFR 1090.55.

Comment:

One commenter requested that attest auditors not check any pipeline specifications, air emissions and other information that may deviate from what is in the registration, since this information is not required to establish compliance with the RFS program.

Response:

The commenter is not clear what they mean by other information that may deviate from what is in the registration or how any of the attest engagement requirements are unnecessary to ensure compliance with CAA and EPA regulatory requirements.

The attest engagement provisions described in 40 CFR subpart E detail the requirements for annual attest engagements under biogas regulatory reform. While attest auditors may include additional information or context to assist readers of their report, information outside of what is described in the regulatorily specified procedures is not expected. For RNG producers, as specified at 40 CFR 80.165(c)(1)(i), attest auditors must review all applicable registration information as part of the annual attest engagement procedures. This would include that the RNG producer has submitted pipeline specifications as part of registration and that certificates of analysis submitted as part of 3-year registration updates met the applicable regulatory requirements. Such review by the attest auditor is important because it verifies that the RNG producer can produce RNG that may be injected into the natural gas commercial pipeline system for use as transportation fuel consistent with CAA and EPA regulatory requirements.

We have tailored the annual attest engagement requirements for biogas producers, RNG producers, and RNG RIN separators to ensure that biogas, RNG, biogas-derived renewable fuels, and RINs for RNG are verified by attest auditors as meeting the applicable regulatory requirements.

We note that because we are not finalizing the submission of air emissions information in the rulemaking, we are also not requiring that attest engagement auditors verify air emissions information.

10.14 Biogas Used as a Biointermediate and RNG Used as a Feedstock

Comment:

Multiple commenters supported EPA's proposal to allow biogas as a biointermediate and RNG used as a feedstock to allow for production of additional biogas-derived renewable fuels.

Response:

We appreciate the comment and have finalized this provision.

Comment:

Multiple commenters urged EPA to finalize biointermediate pathways involving biogas, including but not limited to, biogas to sustainable aviation fuel, hydrogen, and dimethyl ether (DME). Including biogas to biointermediates will allow the industry to fully contribute to reducing greenhouse gas emissions in transportation.

Response:

While EPA is finalizing the biogas regulatory reform provisions, which is a necessary step to allow for biogas as a biointermediate and RNG as a feedstock to produce other biogas-derived renewable fuels, EPA did not propose and is not finalizing any new pathways under this action.

Comment:

One commenter requested that approve RIN generation by RNG sourced by book and claim accounting to make SAF through use of RNG as a biointermediate. The commenter supports EPA's approach to allow RNG to be used as a feedstock through the retirement of assigned RINs and requested that EPA should provide clarity to the regulated and investment communities by specifying its applicability to RNG used to make SAF. The commenter also requests that EPA confirm that the RNG book-and-claim approach outlined in the proposed biogas regulatory reform provisions would apply to RNG used to make SAF.

Response:

We thank the commenter for their support for the proposed approach to using RNG RIN assignment and retirement to allow for the use of RNG as a feedstock. We intend for these provisions to allow for the use of RNG to produce biogas-derived renewable fuels (including RNG used as a feedstock to produce SAF) other than renewable CNG/LNG so long as the fuel meets all applicable statutory and regulatory requirements. Nevertheless, while EPA is finalizing the biogas regulatory reform provisions, which is a necessary step to allow for biogas as a biointermediate and RNG as a feedstock to produce other biogas-derived renewable fuels, EPA did not propose and is not finalizing any new pathways under this action.

Comment:

One commenter requested that EPA provide for RIN parity between RNG used to make SAF and RNG used to make renewable CNG/LNG by establishing an appropriate point of measurement. The commenter noted that EPA proposed such an approach for the generation of RINs from renewable electricity produced from biogas/RNG and that EPA should confirm that it would take a similar approach for RNG used to produce SAF.

Response:

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking. We did not propose and are not finalizing any change to the approach for determining the equivalence value for other renewable fuels, including SAF produced from RNG.

Comment:

One commenter asked for clarity on incentives for using RNG as process energy. The commenter stated that if a renewable fuel producer purchased RNG for process energy, the associated RINs could be retired, but no incremental finished fuel RINs would be produced. The commenter noted that this would be an added cost to the fuel producer but would enable more significant reductions in lifecycle greenhouse gas emissions and noted that the proposal appeared to contemplate this case when using biogas and RNG as a biointermediate. However, the commenter requested that EPA clarify how other fuel producers or plant configurations would benefit from the ability to use and account for RNG used as process energy.

Response:

Parties can currently use biogas or RNG as process heat to meet a pathway as described in 40 CFR 80.1426(f)(12) and we did not propose and are not finalizing any changes to this provision. Certain pathways include the use of RNG as process heat to reduce GHG emission reduction as part of meeting the CAA requirements. Table 1 to 40 CFR 80.1426 mentions biogas used as process heat for some pathways. RNG can also be used to meet those pathway requirements.

To the extent the comments relate to EPA’s proposed definition of “produced from renewable biomass,” we are not taking any final action on defining “produced from renewable biomass” in this rulemaking.

Comment:

One commenter suggested that EPA should require RNG RINs to be retired simultaneously with the generation of RINs for the finished fuel. The commenter pointed out that this would result in no point in the RNG-to-biofuel chain when no RIN exists which would be critical to investors seeking to finance RNG-to-SAF or other biofuels projects using RNG as a biointermediate. The commenter contended that investors will prefer having a RIN that exists at all stages of the process for security and that investors will lose that security if RNG RINs are retired at some point before RINs for the finished fuel are generated.

Response:

We are finalizing 40 CFR 80.1434(a)(11) that specifies RINs assigned to RNG must be retired when that volume of RNG is used to produce other renewable fuel. After the party produces another renewable fuel using RNG as a feedstock, the party would then have five days to enter this transaction into EMTS. For most processes, we expect production of renewable fuel to happen quickly enough that there would need to be little time lag between retiring RNG RINs and generating renewable fuel RINs. However, we want to provide flexibility in cases where a process does take time to produce renewable fuel from RNG.

For RNG used as process heat or for other uses, in order to retire the assigned RIN the party would have to have another valid reason as described in 40 CFR 80.1434.

Comment:

One commenter suggested that EPA should eliminate its “many-to-one” rule that would allow each RNG producer to only contract with one entity that would utilize the RNG biointermediate to make a finished fuel.

Response:

We did not propose nor are we finalizing a “many-to-one” limitation for RNG used as a feedstock, and it is unclear which specific proposed provision the commenter is referring to that would preclude the use of RNG as a feedstock by multiple renewable fuel producers.

Comment:

One commenter requested additional clarification of whether RNG could be used as a feedstock to produce hydrogen in a steam methane reformer that would then be used as a biointermediate to produce a renewable fuel. The commenter suggested that the renewable fuel producer would retire the RNG RIN using the process proposed in biogas regulatory reform and generate RINs for the renewable fuel produced from the hydrogen made from RNG used as a feedstock.

Response:

Since RNG is already substantially altered from the original feedstock, allowing RNG to be used to produce a biointermediate that is then used to produce renewable fuel would involve substantial alteration at three facilities. At this time, due to the additional complication that would arise going from producing renewable fuel at two facilities to producing renewable fuel at three facilities, we are only allowing RNG to be used as a feedstock to produce renewable fuel. That is, at this time the program we have designed will not allow RNG to be used to produce a biointermediate that would in turn be used to produce a RIN-generating renewable fuel. This is due to the concern that the chain of parties involved might become too complicated to effectively oversee. For example, a biointermediate producer might obtain RNG from many RNG producers. Combining that network with a separate renewable fuel producer would become intractable at the present time.

The commenter said that the hydrogen would be used as a biointermediate, which implies it would be shipped to a separate renewable fuel facility. If, however, the hydrogen was used on-site to produce a renewable fuel, hydrogen would not be a biointermediate, and the RNG would be used as a feedstock to produce renewable fuel, which we are allowing under this action.

Comment:

Multiple commenters suggested that the biointermediate transfer limits at 40 CFR 80.1478 make no sense for biogas used as a biointermediate or RNG used as a feedstock and that EPA should relax the rules related to biointermediate transfers for biogas/RNG.

Another commenter suggested that EPA should clarify how the biogas/RNG rules will apply under its current restrictions for biointermediates, including that biointermediate producers may ship biointermediates only to a single renewable fuels producer. The commenter suggested that EPA should relax that rule specifically for RNG, because: (a) RNG will be shipped via natural gas pipelines on a book-and-claim basis and, once injected into the pipeline, the RNG will be indistinguishable from conventional natural gas; and (b) EPA will be able to track RNG use as a biointermediate sufficiently with RNG RINs, such that additional limitations on RNG transfers are no longer necessary.

Response:

The transfer limits for biointermediate in 40 CFR 80.1478 do not apply to RNG used as a feedstock, since that RNG is not a biointermediate.

The transfer limits in 40 CFR 80.1478 apply to biogas used as a biointermediate, and the renewable fuel producer must meet all the requirements. To clarify for the commenter how biointermediate rules would apply, for biogas transported by a private pipeline, the volume of the container specified in 40 CFR 80.1478(h)(1)(i) would be the volume of biogas that flowed through the private pipeline over the period of time for which the batch was generated.

Comment:

One commenter requested EPA provide guidance on the difference between biogas as a biointermediate and RNG as a feedstock and that EPA clarify whether new pathways are needed for RNG to be used to produce other renewable fuels. The commenter urged EPA to finalize any additional pathways as soon as possible.

Response:

Biogas as a biointermediate does not involve placement on a natural gas commercial pipeline system. RNG used as a feedstock must be withdrawn from a natural gas commercial pipeline system.

An example of biogas used as a biointermediate would be a facility that owns a private pipeline and purchases biogas or treated biogas on that pipeline from a biogas producer. Another example would be a renewable fuel producer buying trucked treated biogas that was never placed on a natural gas commercial pipeline system.

An example of RNG used as a feedstock is a renewable fuel producer that withdraws RNG from a natural gas commercial pipeline system and uses that to generate renewable fuel at their facility.

As discussed in the 2020-2022 RFS Standards Rule,[160] we intend for existing pathways to apply to biointermediates. However, we did not intend for facility-specific pathways to apply to biointermediates because the feedstock, production process, and renewable fuel producer are case specific. We note that the finalization of new pathways for the use of biogas as a biointermediate or RNG used as a feedstock is beyond the scope of this rulemaking.

[160] 87 FR 39649-39651 (July 1, 2022).

10.15 Biogas/RNG Storage Prior to Registration

Comment:

Several commenters opposed the proposed provisions to limit the offsite storage of biogas/RNG prior to registration or requested that EPA continue to allow the offsite storage of biogas/RNG prior to registration.

Multiple commenters contended that an important element of the previous biogas provisions in the allowance for the storage of biogas/RNG prior to registration while RFS and state-specific low carbon fuel program registrations are being processed as well as when administrative changes are needed, such as updates to supply chain or contracting partners.

Response:

In the NPRM, we explained that we do not allow storage prior to registration for most fuels because in the course of reviewing an engineering review, we may determine that the fuel was not produced consistently with CAA and EPA's regulatory requirements.[161] If this circumstance happens after RNG or fuel has left the facility, this poses the following problems for the program:

- Companies will have an incentive to start allowing off-site storage early for which they plan to generate RINs, so they may not ensure the engineering review has all the registration requirements, leading to incomplete or inaccurate registration submissions. This increases the time it takes for EPA to review submissions for all parties.
- It is difficult and sometimes impossible to find the RNG or fuel and verify that it meets the statutory requirements, since it has left the facility, and especially in the case of RNG when it is commingled with natural gas in the natural gas commercial pipeline system.
- If a registration submission is not sufficient and multiple pass backs occur with the registrant, the registrant may inadvertently generate RINs for fuel that does not meet the CAA or regulatory requirements. Due to the lack of transparency with how stored RNG is accounted for in RIN generation, identifying this mistake may be impossible.
- There would be more financial pressure to not do an additional site visit if the first site visit was not sufficient.

These factors make it very difficult for EPA to ensure that renewable fuel is made from renewable biomass and ensure that such fuel is used as transportation fuel, heating oil, or jet fuel once the fuel has left the facility. The commenters provide many reasons, outlined in subsequent comments and responses below, as to why they believe offsite storage prior to registration should be allowed to occur. The commenters, however, do not sufficiently explain how EPA should handle situations where a facility's registration is inadequate or incorrect and corrections to the engineering review or the facility are necessary before valid RIN generation can proceed.

[161] 87 FR 80700.

As discussed in Preamble Section IX, part of biogas regulatory reform involves streamlining the registration process so that facilities are registered in a much timelier manner. We believe the streamlined registration process resulting from biogas regulatory reform will obviate the need for storage, at least to the degree it has been utilized in the past. Given that we did not receive adequate alternatives to our proposed approach for ensuring the validity of RINs, we are finalizing the proposed limitation on offsite storage of biogas/RNG prior to registration.

Comment:

One commenter suggested that a potential solution would be to allow for RNG storage using a qualified storage facility (as is currently allowed) while waiting for EPA registration acceptance, and then storage of RNG can cease after approval. Alternatively, EPA could allow the retroactive generation of RINs from gas production in the period between submittal and approval of a facility RFS registration, provided the gas production during this period meets all the requirements of the RFS and a QAP protocol.

Response:

While we appreciate the commenter's alternative suggestions, neither of these alternatives addresses the concerns highlighted in the response to the first comment of this section. In addition, these alternatives raise other concerns. Adding specifications for qualified storage facilities at registration would increase the time necessary to evaluate registrations and runs the risk of the generation of invalid RINs on RNG that failed to meet the applicable CAA and EPA regulatory requirements. This runs counter to the goals of the RFS program and biogas regulatory reform.

Allowing retroactive generation of RINs from the period between submittal and approval incentivizes companies to submit as early as possible, which often results in more incomplete or incorrect information. This would increase the time necessary to review submissions and may delay registration for other facilities. Because we have not allowed other renewable fuel producers to generate RINs for renewable fuels stored offsite prior to registration, we also believe that allowing RNG producers to do so would create an unlevel playing field.

Comment:

Multiple commenters stated that this limitation would decrease volumes which conflicts with the goals of RFS.

Response:

Given that this limitation only impacts onboarding new RNG production facilities into the program, we do not expect it to have a measurable effect on the volumes of RNG produced and RINs generated on RNG. The commenter does not explain the magnitude that this effect would have, given the streamlined registration discussed above. In addition, for the reasons discussed in Section IX.N and in this section of the RTC, allowing for biogas/RNG storage offsite has multiple negative program outcomes, one of which significantly increases the opportunity for the generation of invalid RINs from biogas/RNG. Potentially increasing volumes at the expense of those volumes being qualifying renewable fuel would be inconsistent with goals and requirements of the RFS program.

Comment:

One commenter said that some biogas producers have contracts to provide biogas to other RNG producers/RIN generators that effectively obliges them to utilize offsite storage. This could result in difficult short-term business decisions for early adopter producers to reduce rather than increase levels of biogas and RNG available on the grid, and adversely impact the program by removing critical storage capabilities.

Response:

In this action we are not prohibiting parties from injecting gas into natural gas commercial pipeline systems and storing that gas off-site. The RNG producer would just not be able to generate RINs for that gas injected into the natural gas commercial pipeline prior to registration. The commenter did not specify how the regulatory requirements would prevent the storage of gas as specified in their contracts. As discussed in RTC Section 10.5, we are extending the implementation date, which gives parties additional time to adjust contracts, if necessary, which may alleviate some of the commenter's concerns.

Comment:

Multiple commenters stated that the requirement to sample and test biogas and RNG and place this information in the engineering review increases the time between the facility being operational and the facility being registered. The commenters stated that this will result in more RNG being produced prior to registration.

Response:

We are not finalizing the proposed requirement for biogas or RNG to be tested in the initial engineering review due to concerns that it would delay registration. This change from the proposal will allow facilities to have an initial engineering site visit before starting up, reducing the impact of only allowing onsite storage prior to registration. We believe removing this requirement will further streamline the registration process and lead facilities to generate RINs sooner.

Comment:

One commenter stated that with limited professional engineer availability and with the requirement to sample and test biogas and RNG, facilities may produce RNG for weeks or months before registration is finalized.

Response:

The commenters did not fully explain why limited availability of professional engineers is relevant to this provision. Under the prior allowance, RINs could not be generated prior to an engineer site visit, so a delay caused by professional engineer availability would impact RIN generation even if storage is allowed between the site visit and registration.

Comment:

One commenter recommends a provisional registration for RIN generation prior to final registration with the following attributes:

- Prior to start-up, a facility could provide notice of its intent to produce RNG, along with other pre-registration information as prescribed by EPA. On that basis, EPA could grant provisional status within EMTS. Provisional RINs could then be generated and assigned to volumes of RNG produced by the RNG Producer and injected in the commercial distribution system.
- Provisional RINs could be controlled by denying the right to separation prior to the final registration of the RNG Producer. Upon registration, separation could occur.
- A provisional system would maintain the streamlined RIN generation system EPA is trying to create, as well as the RIN assignment and separation points. All volumes would be entered in the EMTS system, ensuring the tracking and transparency EPA is seeking, and avoidance of double counting or mis-use of RINs."

Response:

In the NPRM,[162] we explained our reasoning for limiting off-site storage prior to registration. We had concerns that RNG could be produced inconsistent with EPA's regulatory requirements and therefore, not be eligible for RIN generation. For companies that expect their product to qualify, this could result in invalid RIN generation, as discussed in the first response in this section. While the commenter's recommended provisions might help with transparency regarding the time period for which RINs are generated, it does not handle the perverse outcomes that might arise from having an incomplete registration package.

Further, the commenter's suggestions would not be simple to put in place or implement, placing significant burden on EPA all for the purpose of addressing only a short-term concern at the startup of new facilities. We believe our streamlined registration process will obviate the need for any such provisions. Finally, given that provisional registrations are not something we

[162] 87 FR 80700.

proposed and would be new in RFS, we believe a change like this, if merited, should go through a notice and comment process.

Comment:

One commenter said that EPA also may need to clarify 40 CFR 80.1458(a), which references "renewable fuel producers," to make clear these provisions apply to biogas and RNG.

Response:

We have added reference to RNG producers in 40 CFR 80.1458 to make it clear that the provisions apply to RNG.

Comment:

Multiple commenters noted that there is currently a paper trail which tracks the RNG from injection (i.e., utility meter statement) to the off-taker (i.e. PTD or invoice) to a physical storage entity (i.e. invoice). The commenters further noted that physical storage entities have statements which can be used to confirm that more physical gas is being stored than the volume of RNG produced and nominated from the facility and suggested that all of the documents may be specified by EPA under their recordkeeping requirements.

One commenter noted that requiring on-site storage is unnecessary given the current requirements for a completed engineering review prior to storage as well as inclusion of detailed storage documentation during registration.

Response:

While recordkeeping allows for auditor verification and enforcement, since the records are not reported to EPA they do not assist with some of the oversight of the program. For example, if a party accidentally over-generated RINs for gas stored offsite because they used the wrong registration submission date, the commenters' approach would not enable EPA to identify the error if the party just holds the records.

Comment:

Multiple commenters suggested that the mechanism of storage prior to registration allows for preserving of renewable attributes and once an RFS application has been approved by EPA, then stored gas is dispensed for use as transportation fuel and RINs are subsequently generated. The commenters noted that as the applicant pool continues to grow there will be an increase in workload placed upon EPA and third-party verification bodies to register new parties which has resulted in delayed application processing time of up to 6 to 9 months. Such a loss could lead to a huge financial deficit for new projects.

One commenter suggested that EPA should continue to allow biogas storage prior to registration because it has allowed it in the past, and that EPA forecasted that registration acceptance would take more time because of the influx of new registration in the eRINs program.

One commenter argued that the proposed rule would place new and increased regulatory burdens on entities such as farmers, small business, and municipalities that want to participate in the RNG value chain, especially regarding the storage of fuel and its equipment. The commenter suggested that RNG growth and the implementation of eRINs would increase the length of time between when RNG registration is submitted to EPA and registration is granted. The commenter argued that the revenue lost by removing the ability to store RNG in FERC regulated natural gas storage facilities and by forcing on-site storage, which is extremely expensive and restrictive, will be immense and is some instances prevent the development of a RNG project thereby reducing the supply of RNG.

One commenter noted that the ability to store is fundamental to the economic viability of new RNG projects because EPA acceptance can often take up to 6 months and that EPA is already operating under a heavy administrative burden and that burden will only multiply once the Agency starts implementing simultaneously both the renewable electricity pathway and biogas reform.

Response:

In the NPRM, we explained that the changes we proposed, and are now finalizing, to the registration process would result in shorter registration times and would obviate the need for off-site storage prior to registration. The commenters do not acknowledge that the simplified registration requirements in this action would impact timing of registrations. The initial registration package no longer requires contracts or certificates of analysis, eliminating most of the information that parties would need to submit, and EPA would need to review, for registration. We expect this would lead to a significant decrease in registration timing as opposed to the increases in registration timing feared by the commenters. Further, we are not taking any final action on eRINs in this rulemaking, so concerns with respect to any impact it may have had on the timing of processing registration applications are now moot.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

Multiple commenters suggested that EPA should not finalize the proposed limitation on storage for biogas/RNG prior to registration because EPA has not demonstrated any cases of fraud related to biogas storage prior to registration.

Response:

We explained in the NPRM that the limitation on off-site storage prior to registration is necessary to ensure the RNG that generates RINs actually qualifies under the program.[163] We have identified a vulnerability in our existing approach, which does allow offsite storage prior to registration, and are remedying this vulnerability in this action. Additionally, due to the changes we are making to the program under biogas regulatory reform, we believe offsite storage prior to registration, which is not permitted for other fuels under the RFS program, will no longer be necessary or warranted as a flexibility for biogas/RNG.

Comment:

Multiple commenters raised concerns about the cost of implementing onsite storage. The commenters stated that onsite storage would be impractical for biogas producers. The commenters stated this could deter future growth in the RFS program.

Response:

While we are finalizing as proposed to allow on-site storage prior to registration, we are not requiring facilities to store on-site. The decision to store on-site is left up to companies to decide. We recognize that on-sight storage may be prohibitively expensive for RNG (and this may be true of other fuels in the program as well). However, the desire to avoid this cost does not supersede the need to ensure that renewable fuel is produced according with the applicable CAA and EPA regulatory requirements, as described in the NPRM.[164] There is no requirement that these parties participate in the RFS program and generate RINs. The generation of RINs under the RFS program provides them with an additional revenue stream to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

Comment:

One commenter noted that requiring on-site storage is unnecessary given the current requirements for a completed engineering review prior to storage as well as inclusion of detailed storage documentation during registration.

Response:

As stated in the NPRM, we have not allowed onsite storage prior to registration for other fuels because EPA may determine that the fuel was not produced consistently with CAA and EPA's regulatory requirements and therefore, not be eligible for RIN generation.[165] We have received engineering reviews in the past which are not complete or accurate, and this has complicated the ability to ensure that the proper number and type of RINs were generated for the stored biogas. The commenters do not explain why just having an engineering review conducted, even if it is

[163] 87 FR 80700.
[164] 87 FR 80700.
[165] 87 FR 80700.

not compliant with the applicable regulatory requirements, should be sufficient to warrant offsite storage of gas prior to registration.

We discuss the issues with providing detailed storage documentation at registration in an earlier response in this subsection, including longer registration timelines. We did not propose and are not finalizing detailed storage documentation prior to registration. The information supplied at registration under the previous biogas provisions was intended to demonstrate the contractual network that followed the biogas from production to its ultimately use as renewable CNG/LNG under the regulations at 40 CFR 80.1426(f)(11). As discussed in Preamble Section IX, we no longer need to collect this contractual information because the RIN generated for and assigned to the RNG will track the movement of the RNG through the natural gas commercial pipeline system. The removal of the requirements for the submission of contracts will significantly simplify the registration process and reduce the administrative burden on registrants and parties in the chain.

Comment:

One commenter suggested that the proposed rule will place new and unnecessary burdens on municipalities by greatly restricting storage of RNG prior to registration.

Response:

We recognize that prohibiting offsite storage prior to registration may limit some RNG production facilities from generating RINs for gas produced prior to registration. After registration, we do not see this as placing any limitation on regulated parties. The commenter does not explain why this limitation would impact municipalities in particular. It applies equally to all facilities prior to registration.

The commenter also did not address why this limitation is unnecessary given our concerns, as mentioned in the NPRM,[166] Preamble Section IX.A.4, and the above responses to comments.

Comment:

Multiple commenters noted that current storage regulations allow RNG projects the ability to not have to dispense and monetize RNG immediately upon producing it. Many projects need storage for registration purposes in various state programs, like the California Low Carbon Fuel Standard (LCFS) until a Provisional Pathway is approved by the California Air Resources Board (CARB). Dispensing gas prior to receiving this approval is a sub-optimal decision and potentially creates a timing mismatch between RFS and LCFS programs.

Multiple commenters noted that the current storage regulations allow RNG projects the ability to store and monetize RNG immediately while allowing enough time for State program registration

[166] 87 FR 80700.

and pathway verification, thus optimizing value as municipalities seek the benefits of both programs.

One commenter said, “these storage regulations will also create conflict between state and federal biofuels programs. Many projects need storage for registration purposes in various state programs. For example, California’s Low Carbon Fuel Standard (LCFS) requires storage until a Provisional Pathway is approved by the California Air Resources Board. Dispensing gas prior to receiving this approval is a sub-optimal decision and potentially creates a timing mismatch between RFS and LCFS programs.”

One commenter noted that the current rule allowing for virtual storage is consistent with book-and-claim practices accepted by other compliance programs across the U.S.

Response:

Commenters failed to specify how not allowing offsite biogas/RNG storage prior to registration would conflict with California’s LCFS or other state programs. The RFS program has different statutory and regulatory requirements than other programs, such as LCFS. While we aim to not conflict with other programs, it may be necessary to put forth requirements that differ from other programs in order to satisfy our statutory obligations. In this instance, we explained our reasons for limiting offsite storage prior to registration in the NPRM.[167] The commenters did not address these reasons, including EPA’s concern that offsite storage makes it more likely that RINs will be generated for fuel that was not produced consistently with EPA’s regulatory requirements.[168]

Further, we have taken steps in the final rule that we believe will assist with how RFS requirements interact with state program requirements such as LCFS. For example, we are not finalizing a requirement that certificates of analysis be provided at initial registration, allowing for an engineering review to occur prior to facility start up. We believe this will better streamline registration and reduce the timeline from when RINs can be generated.

Comment:

One commenter suggested that EPA could allow offsite storage for a period of six months while registration is pending. Once the registration processes are streamlined, EPA could reduce the eligible offsite period to 60-90 days, or sunset the provision altogether. Another commenter suggested that EPA should allow for storage of initial production volumes for up to 90 days prior to EPA acceptance of a registration.

Response:

In the NPRM and Preamble Section IX.A.4, we stated our concerns around allowing for offsite storage prior to registration.[169] These concerns are valid regardless of the amount of time which off-site storage is allowed; it is not the amount of time that biogas/RNG stored offsite that causes

[167] 87 FR 80700.
[168] 87 FR 80700.
[169] 87 FR 80700.

the potential for invalid RIN generation, it is the fact that EPA has not determined whether the biogas/RNG could meet the applicable CAA and EPA regulatory requirements. The commenters do not explain how allowing offsite storage for a limited period of time alleviates our concerns mentioned in the NPRM. The amount of time that offsite storage occurs may affect the number of potentially invalid RINs but does not resolve the underlying problem.

Comment:

One commenter pointed to their own experience where they were allowed to store biogas on a FERC regulated pipeline for 14 months as an example of why EPA should continue to allow biogas storage prior to registration.

Response:

The commenter does not make clear why an example of past allowance alleviates our concerns stated in the NPRM[170] and Preamble Section IX.A.4. From our experience, as discussed in earlier responses in this subsection, we have concerns about how allowing offsite storage prior to registration creates vulnerabilities. As noted in the proposal and Section IX of the preamble, by eliminating the need for the submission of detailed contracts following the biogas from the biogas production facility to its ultimate use as transportation fuel, we expect that registration acceptance to occur in a much timelier manner, much less than the 14 months the commenter noted. Additionally, as discussed in Section IX.H.1 and Section 10.7, we have further simplified the registration procedures for biogas and RNG producers. So long as registration submissions are complete and accurate, we anticipate minimal delays in acceptance.

Comment:

One commenter suggested that the new storage restrictions will force RNG producers to sacrifice substantial value by creating a timing mismatch between RFS and LCFS program registration and pathway verification timelines.

Multiple commenter noted that most RNG facilities do not have onsite storage and have no other option but to inject their gas into the pipeline and store offsite while awaiting registration approval. The commenter noted that there would be significant value lost for these facilities, which are already cash constrained and that this change is most impactful to small and medium-sized RNG developers who have limited resources, e.g., investment capital, physical footprint, and expertise. It will also reduce the timing for investment payback, creating another barrier to entry for new development.

One commenter stated that storing RNG production during EPA approval process is critical to the early economics of a project.

One commenter said that the limitation would be financially disastrous for RNG producers.

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[170] 87 FR 80700.

One commenter noted that the current rule allowing for virtual storage is also an important mechanism for keeping costs reasonable.

Response:

The commenters do not address the concerns that the stored fuel was not produced consistently with EPA's regulatory requirements and therefore, not be eligible for RIN generation.[171] As stated in the NPRM,[172] given the simpler registration process, we do not believe allowing RIN generation for off-site storage prior to registration is needed because the simplified registration requirements for biogas and RNG producers should minimize the amount of time needed for acceptance by EPA. In addition, we have further streamlined the registration process from what was proposed, limiting any lost value from this provision.

The commenters do not provide data showing how this provision may financially impact parties, so it is unclear the magnitude of the impact. The time between producing RNG and being registered should be substantially shorter than the current time. This should substantially reduce the impact of this limitation on RNG producers. Further, there is no requirement that these parties participate in the RFS program and generate RINs. The generation of RINs under the RFS program provides them with an additional revenue stream to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

Comment:

One commenter that opposed the limitation on offsite storage prior to registration has requested that EPA delay implementation of this provision.

Response:

We have delayed the implementation of biogas regulatory reform until July 1, 2024, as discussed more in RTC Section 10.5.

[171] 87 FR 80700.
[172] 87 FR 80700.

10.16 Single Use Limitation

Comment:

Multiple commenters opposed the proposed limitation to only allow a biogas production facility to supply biogas for one purpose under the RFS program.

One commenter contended that the single use limitation would prevent the inclusion of some volume of biogas at affected biogas producers' facilities for use under the RFS program.

One commenter also noted that diverse revenue opportunities for biogas are essential continued investment in biogas which runs counter to EPA's goal of stability and growth in the program. One commenter suggested that EPA does not restrict other producers under the RFS program to a single product and should not make an exception for biogas. The commenter argues that the existing RFS QAP program is sufficient to ensure RIN legitimacy, even with multiple biogas uses. The commenter expressed concern that this limitation could exclude many larger sites that already have electric and RNG operations. These operations typically would have separate equipment from which it receives the biogas and, due to monitoring of volumes, should not result in double counting. They believe this would not exclude a site that has more than one RNG facility, so long as that is the only "use" of the biogas at that site.

One commenter said that this limitation would invalidate several sites that are already producing or under construction, citing that a company that has already committed over $200 million to three projects that will create new RNG facilities to utilize excess biogas that cannot be used by the existing onsite waste-to-energy plant. The commenter states that the proposed limitation retroactively penalizes firms.

Multiple commenters requested that EPA clarify that having multiple uses of the biogas at a particular location should not exclude that facility from participating in the RFS program. Instead, one commenter recommends that EPA could require information on the production and disposition of all biogas sources at a particular location.

Response:

We are finalizing as proposed the single use limitation for biogas. As discussed in the NPRM and Preamble Section IX.O, our concerns motivating biogas regulatory reform are to ensure oversight and reduce the risk of double counting. The single use limitation helps achieve these aims in the following ways:

- When an auditor is looking at the facility, they do not need to verify that the biogas volumes that are used for other purposes are consistent with the volume of biogas reported since biogas can only be used for a single purpose.
- Given that biogas can only go to one use, a biogas producer cannot overstate the volumes that they send to two different uses.

We acknowledge that this limitation may impact some facilities that use biogas for multiple purposes and lead to some volumes to not be used under RFS. However, we believe this tradeoff is justified because the single-use limitation provides the oversight that is necessary to ensure all volumes used under RFS meet CAA requirements especially now that biogas has additional qualifying uses under the RFS. The simplicity provided by this limitation helps achieve the aims of biogas regulatory reforms and ensure renewable fuel is produced consistent with CAA requirements. Below we respond to commenters' specific concerns.

With this single use limitation, we are not reducing the diversity of options available to biogas producers. Biogas producers have the option to choose one qualifying use, which still provides the facilities with a diversity of options. The facilities can still produce the biogas for other uses, and they can market those products outside the framework of RFS. Thus, the diversity of potential revenue streams still exists. For facilities that also produce products and market them outside the framework of RFS, we are not requiring the same level of information about products that fall under our regulations.

We have previously limited use of products under the RFS, and this limitation would be consistent with that. For example, a biointermediate producer is only allowed to sell their biointermediate to a single renewable fuel producer.

We discuss why QAP is not a substitute for biogas regulatory reform, including this provision, in RTC Section 10.12.

As discussed above, this limitation will not exclude facilities from participating in the program if they use biogas for multiple uses. Only one of those uses can fall under the RFS program. While some facilities might have the appropriate metering, this might not be true for all facilities, and removing this limitation without additional requirements would still not ensure volumes of renewable fuel are produced consistent with CAA requirements.

Finally, it is worth highlighting that there is no requirement that these parties participate in the RFS program and generate RINs. The generation of RINs under the RFS program provides them with an additional revenue stream to fund their operations and improve profitability. But it will be their business decision to weigh whether the benefits of participation outweigh the regulatory oversight burden.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

Multiple Commenters stated that allowing biogas to be used for multiple uses should not cause double counting concerns since volumes of biogas are closely monitored to comply with air permits and EPA's GHGRP.

Response:

While some facilities do fall under EPA air permits and the Green House Gas Reporting Program, some facilities may be too small to be regulated by some of these programs. As such, these facilities do not have as much oversight. In addition, other programs have different goals than the use of renewable fuel for transportation, so the data obtained by these programs is likely in a different format and does not provide adequate oversight for the specific needs of RFS compliance. In general, information gathered pursuant to other programs is of limited value in ensuring that biogas is produced from renewable biomass and ultimately used as transportation fuel and are unrelated to whether a RIN is generated validly or transacted consistent with EPA regulatory requirements. For example, monitoring of volumes at the biogas production facility does not necessarily translate to information that is necessary to prevent double counting when the biogas leaves the facility. Given these factors, we still believe the single use is necessary to effectively oversee the program.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter said that the biogas is not commingled, which already prevents double counting.

Response:

While biogas is not typically commingled, EPA is concerned that natural gas may be added to biogas when sent for multiple uses, allowing for RINs to be generated for something other than renewable fuel. The commenter does not explain how this type of double counting is addressed.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter recommended that instead of this restriction, EPA mandate QAP for landfills that use biogas in more than one RNG production facility or renewable electricity generation facility. The commenter proposed regulatory text changes. Another commenter also said that this restriction can be addressed by mandatory QAP.

Response:

As discussed in RTC Section 10.12, QAP is not a substitute for regulatory reform since QAP providers check for compliance with the current regulations and do not themselves create a system that is overseeable. Allowing biogas producers to send biogas for multiple uses and facilities to accept biogas from multiple facilities can create complex networks that would be complicated to oversee. By limiting biogas to a single use at a biogas production facility, this condition improves EPA's ability to oversee the program. To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter said this would decrease investment in renewable fuels.

Response:

The CAA directs us to promulgate regulations "to ensure that transportation fuel sold or introduced into commerce in the United States (except in noncontiguous States or territories), on an annual average basis, contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel."[173] As discussed in earlier responses in this subsection, we are finalizing these regulations to ensure renewable fuel that is used to satisfy the statutory volume requirements actually qualifies under the CAA requirements, which includes preventing double counting.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter said that instead of the limitation EPA should rely on the metering of biogas into the RNG producer or electricity producer facility and compare the amount of biogas from a given facility to the production capacity reported by the RNG producer or renewable electricity producer. This approach would provide EPA assurance that any double counting is mitigated, if not eliminated.

Response:

We agree with the commenter that metering of biogas does increase accountability, and we are finalizing metering requirements to support that goal. However, as mentioned above, allowing biogas producers to send biogas for multiple uses and facilities to accept biogas from multiple facilities can create complex networks that are complicated to oversee, even with accurate meters. Metering allows for data about the volumes but does not decrease the complexity of the networks.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

[173] 42 USC 7545(o)(2)(A)(i)

Comment:

One commenter suggested that EPA revise the single use limitation to not apply to landfills because independent flows are already metered and reported to EPA through other regulatory efforts.

Response:

While some landfills do fall under EPA air permits and other regulatory programs, some may be too small to be regulated by some of these programs. As such, these landfills do not have as much oversight. In addition, other programs have different goals than the use of renewable fuel for transportation, so the data obtained by these programs is likely in a different format and is not sufficient for the specific needs of the RFS program. In general, because information collected under other programs is tailored for a different purpose, information gathered pursuant to other programs is of limited value in ensuring that biogas is produced from renewable biomass and ultimately used as transportation fuel and are unrelated to whether a RIN is generated validly or transacted consistent with EPA regulatory requirements. For example, monitoring of volumes at the landfill does not necessarily translate to information that is necessary to prevent double counting when the biogas leaves the landfill. Given these factors, we still believe the single use is necessary to effectively oversee the program.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter suggested that EPA should leverage separate meters and QAP verification in lieu the proposed single use limitation.

Response:

While separate meters can help with potential double counting, allowing multiple uses still increases the complexity of the program, and makes it difficult to identify double counting. For example, if meter data is switched, this could lead to higher volumes and create a double counting issue. Mandating QAP can increase oversight, but as discussed in RTC Section 10.12, is not a substitute for effective program design.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter requested that EPA should confirm that biogas from a single source can be used for the same purpose by two separate co-located RNG production facilities. The commenter also requests that EPA clarify that these provisions would not bar existing operations in which two RNG plants are co-located at a single biogas-producing landfill.

Response:

The single use limitation applies based on usage, so biogas from a single source can be used for the same purpose by two separate co-located RNG production facilities. These provisions allow for existing operations in which two RNG plants are co-located at a single biogas-producing landfill to produce RNG.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter suggested that EPA should clarify that parties can use biogas to generate electricity or supply biogas for producing CNG/LNG, while at the same time producing RNG as a biointermediate. The commenter noted that EPA's proposed definitions of "Biogas used as a biointermediate" and "Biointermediate" apply to biogas used to produce biofuels "other than renewable CNG/LNG or renewable electricity" and that should mean that biogas used to produce renewable CNG/LNG or renewable electricity is not subject to limitations that apply specifically to biointermediates. In other words, the commenter said that under the proposal a biogas producer could supply biogas for CNG/LNG or electricity generation as well as to a renewable fuel producer using biogas as a biointermediate.

Response:

The single use limitation in 40 CFR 80.105(k)(1) restricts a biogas producer to only use biogas produced at a biogas production facility for a single use. A biogas producer could not supply biogas from the same biogas production facility in order to produce renewable CNG/LNG and to produce a renewable fuel producer using biogas as a biointermediate.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

10.17 Other Biogas Regulatory Reform Comments

Comment:

One commenter stated that 40 CFR 80.105(k)(4) and 80.155(b)(5)(ii) are very confusing and appear to prohibit municipal wastewater plants from receiving any feedstock which is less than 75% cellulosic.

Response:

Digesters at a municipal wastewater treatment facility which are registered to accept feedstocks that are not predominantly cellulosic are considered other waste digesters and are not subject to the restrictions and requirements in 40 CFR 80.105(k)(4) and 80.155(b)(5)(ii). We have added this clarification to the regulations in 40 CFR 80.105(k)(4).

Comment:

One commenter recommended adjusting the tenses of the language in § 80.145(c)(3) to use 'is or may' instead of 'will' to allow for flexibility in market conditions. The recommended text is "A description of how the biogas is or may be used (e.g., RNG, renewable CNG/ LNG, or renewable electricity)".

Response:

We believe adjusting the tenses as the commenter proposed reduces the need for biogas producers to affirm how the biogas will be used and will make it more difficult for EPA to oversee and enforce the program. We intend for parties to know, at the time of registration, how the biogas will be used. Since biogas is often physically and contractually connected to its use to produce RNG, electricity, or other uses, we do not anticipate many changes in biogas usage due to market conditions. If a change is needed, biogas producers can update their registration information.

Part of having an overseeable biogas program involves incentivizing parties to ensure compliance through the supply chain. Having biogas producers state how their biogas will be used encourages them to verify that the biogas is being used in accordance with their registration, incentivizing compliance. The commenter does not explain how the change would benefit the oversight of the program. Given this concern we are not finalizing a change to the tenses in § 80.145(c)(3), as recommended by the commenter.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter said that RNG producers should be able to determine the best market at any time, not just once a year.

Response:

We did not propose to limit RNG producers to transacting RNG RINs to a single party per year, and the commenter did not clearly state which portion of the proposal imposed such a limit. Under biogas regulatory reform, RNG producers are able to transfer RINs and the associated volume of RNG to any party that is registered to be able to take title to RINs (e.g., the party is registered as a RIN owner, renewable fuel producer, obligated party, etc.) so long as all applicable regulatory requirements are met.

Comment:

One commenter said that language in 80.1426(f)(11) should be changed from ‘derived from biogas’ to ‘derived from renewable biomass.’

Response:

We have adjusted the language at 40 CFR 80.1426(f)(11) to utilize the definition of RNG that we are finalizing which is required to be derived from renewable biomass, consistent with the commenter’s suggestion.

Comment:

One commenter says that the final rule should allow for the continued flexibility for producers to utilize marketers and agents for the performance of various compliance steps for RIN generation, separation, and monetization. One commenter stated that this could be done through delegation.

Response:

In the NPRM, we stated that the biogas regulatory reform provisions are necessary to ensure adequate oversight and avoidance of double-counting.[174] One of the reasons we discussed in the NPRM was that we are requiring RNG producers and RNG RIN separators to register to track RNG through the system, which is a departure from the previous flexibility that allowed marketers to register and generate RINs instead of the RNG producer. The commenter does not explain how continuing the previous flexibility would allow for adequate oversight and avoidance of double-counting, given this reason and others described in the NPRM.

We also note that while we are not allowing marketers to register in lieu of RNG producers, existing compliance flexibilities allow for third-party agents to submit compliance reports, including for RIN generation and separation, on behalf of companies. In this rule, we are not changing these flexibilities.

[174] 87 FR 80692-80693.

Comment:

One commenter said that EPA references RINs for RNG used as process heat, which arguably does not fall under EPA's definition. The commenter stated that, EPA appears to be requiring retirement of RINs for RNG used as process heat, although the commenter found no explanation for this in the preamble. The commenter contended that EPA does not explain why it has these specific requirements for RNG used as process heat and that EPA providing proposed regulatory language is not sufficient to meet EPA's notice and comment requirements. Regardless, the commenter believed that EPA could handle this provision by, as noted above, allowing any RNG RINs produced to be retired in the event of a change in designation of use, such as for use as process heat.

Response:

EPA's proposed definition of RNG included a requirement for the use of the RNG as follows: "It is used or will be used in the covered location as transportation fuel or to produce a renewable fuel." The definition of renewable fuel also contains a provision about the use of such fuel, stating that renewable fuel must be "used to replace or reduce the quantity of fossil fuel present in a transportation fuel, heating oil, or jet fuel." These regulatory requirements are consistent with the statutory definition of renewable fuel as "fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel."[175]

When renewable fuel is used for non-qualifying purposes, for example, for process heat, we require the RINs associated with it to be retired as required under 40 CFR 80.1434(a). The provisions the commenter is discussing for RNG RIN retirement provide similar assurances to the requirements for renewable fuel. The commenter does not explain why RNG RINs should be treated differently in this instance than other renewable fuel RINs.

As stated in the NPRM, we proposed biogas regulatory reform to ensure effective oversight and avoid double counting. Retiring of RNG RINs for RNG that is not used as transportation fuel is necessary to ensure that RNG is not also counted for use as transportation fuel. The commenter provides no explanation as to why removing this provision would still provide the necessary assurance to avoid counting the volume both use as transportation fuel and for another use. Given this, we are finalizing the RNG used as process heat provisions as proposed.

To further clarify that we intend for parties to retire RINs for RNG used as process heat under 40 CFR 80.1426(f)(12), we have included language in the RNG RIN retirement provisions to indicate that this is required (see 40 CFR 80.125(e)(3)).

As discussed in Section 12.3, we have met the notice and comment requirements under the Clean Air Act, and as discussed in Preamble Section IX and throughout this RTC, we are finalizing regulatory provisions that include input from affected stakeholders and providing several clarifications that will establish regulatory provisions for biogas in a manner that will allow EPA to effectively oversee the program.

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[175] 42 USC 7545(o)(1)(J).

Comment:

One commenter encouraged EPA to continue to support third party participation in the RFS.

Response:

Third parties provide a range of services to entities participating in the RFS program. This includes completing engineering reviews, RIN verification, attest audits, compliance reports and registration updates but, as discussed in Preamble Sections IX.C and D, does not include the generation or separation of RINs for RNG. We designed our IT tools and associated processes to incorporate third party participation across this range of services and will continue to do so as we implement the biogas regulatory reform requirements.

Comment:

Multiple commenters stated that EPA did not meet the notice and comment requirements to finalize provisions within biogas regulatory reform.

One commenter stated that many provisions in the proposal do not meet the three requirements in 42 U.S.C. § 7607(d)(3): (1) the factual data on which the proposed rule is based, (2) the methodology used in obtaining the data and in analyzing the data, and (3) the major legal interpretations and policy considerations underlying the proposed rule. The commenter continues: "EPA's main assertion for the proposed changes is that the biogas regulatory reforms are needed to avoid double counting and increase oversight. But these claims are wholly inadequate to support many of the proposed changes, and to our knowledge there have not been instances of double counting or fraud in the RNG industry that would indicate such reforms are necessary. EPA's proposal goes well beyond ensuring compliance with the RFS program without clear identification of EPA's authority to do so. Nor does EPA provide the factual basis for many of its conclusory statements or concerns. For example, EPA's preamble fundamentally fails to explain the basis of its concerns regarding oversight where volumes of RNG injected into commercial pipelines are monitored and tracked by third-party owned meters and the vast majority of RNG projects utilize a QAP. It is also questionable whether several of these new requirements, such as identifying the pipeline specifications for RNG, relate to or address EPA's concern with oversight and double counting."

The commenter continued: "Because of EPA's delay in issuing the proposal, which resulted in the comment period stretching over the holidays, and the number of issues in the proposal, RNG Coalition requested a 30-day extension of the comment period. EPA denied the request simply on the grounds that it is subject to a consent decree to issue the final rule by June 2023. EPA's denial of the RNG Coalition's request for extension of comments is flawed and fails to address the numerous concerns raised by the industry. While EPA acknowledges that the consent decree only applies to the 2023 volume, it claims that it must finalize the entire package. This ignores that the biogas regulatory reforms are not proposed to start until January 1, 2024 and that it is well within EPA's authority to finalize a rule in different actions. For example, the Renewables Enhancement and Growth Support Rule included numerous proposals, for which EPA gave an extension of time for the public to comment. Several aspects of that proposal have been finalized in different rulemakings, including EPA re-proposing some of those changes here. There is no reason that EPA must tie these provisions to the court deadline for the 2023 volumes. Moreover, as noted above, EPA indicated how it could finalize the rest of the proposal without the biogas regulatory reforms, which again EPA fails to address in its response. We believe EPA's denial of this request was arbitrary and that the limited time provided placed restrictions on the public's ability to meaningfully comment."

Response:

EPA's rulemaking process has complied with the procedural requirements of CAA section 307(d)(3). While we decline to reiterate the entirety of the record we provided at proposal here, we emphasize that the major policy consideration underlying the rule is to allow for the expansion of the biogas/RNG program to include the use of biogas as a biointermediate and RNG as a feedstock for the production of fuels in addition to CNG/LNG. In order to do so, however, we must have the tools necessary to ensure that fuels produced using biogas/RNG are actually produced from renewable biomass under an EPA approved pathway and used for transportation. Through the experience we have gained implementing biogas/RNG pathways since 2014, we have learned that the complexities of the system, including biogas/RNG's fungibility with fossil natural gas, make ensuring compliance with these fundamental statutory requirements especially challenging. Regardless, the regulations we proposed and are finalizing in this action fall under the same authorities EPA has been using for over a decade to implement and oversee the RFS program, which include but are not limited to CAA sections 211(o)(2)(A)(i) and (iii), 114, and 301. These regulations are necessary to reduce the risk of double counting volumes and other erroneous or fraudulent behavior, which can result in the generation of RINs for fuel that does not qualify as renewable fuel. When invalid and/or fraudulent RINs are generated, transacted, and used for compliance with an RVO, the program fails to operate to ensure that transportation fuel sold or introduced into commerce in the United States contains at least the required volumes of renewable fuel. EPA has recognized the risk of invalid and/or fraudulent RINs being generated and is taking reasonable steps to proactively prevent this from occurring, e.g., by mitigating the opportunities for volumes of RNG to be miscounted when they are placed on a commercial pipeline together with fungible volumes of RNG and/or fossil natural gas and by ensuring that RNG that is purportedly injected onto a commercial pipeline in fact is capable of being so injected. Given the vulnerabilities that EPA has identified, it would be unreasonable to wait until they have been exploited to take steps to prevent invalid or fraudulent RINs from being generated.

EPA also presented factual data for which we were basing this decision (e.g., the complex network of contracts resulting from the allowance of any party to generate RINs and the lack of separation of RIN generator and RIN separator).[176] We explained how we analyzed the data (e.g., evaluating the ability for the program to be effectively overseen and for EPA and auditors to identify volumes of renewable fuel that may be double-counted).[177] We discussed how the provisions in biogas regulatory reform assist in oversight and preventing double counting in the NPRM, the Preamble, and this document. Specifically, RTC Sections 10.4, 10.7, 10.11, and

[176] 87 FR 80692-80700
[177] 87 FR 80693-80700

10.12 discuss the specific examples the commenter provided in this comment. We also describe our legal authority for taking this action in RTC Section 2.

We have addressed comments related to the length of the comment period for this action in RTC Section 12.3.

Comment:

One commenter stated EPA should continue to work with the RNG industry to remove the confusion and streamline the regulations prior to finalizing. While EPA has expressed an openness to revising the regulations at a later date, that process can take a long time and given the potential for significant impacts on the RNG market and potential liability facing numerous entities, EPA must get these provisions right today. Nor did the commenter believe providing guidance is sufficient as guidance is non-binding, and EPA has a history of adding new substantive requirements for the RFS program without undergoing notice and comment rulemaking. In any event, a potential ability to clarify later should not alleviate EPA's obligation to write the regulations in plain and understandable terms.

Response:

As discussed in Section 12.3, we have met the notice and comment requirements under the Clean Air Act, and as discussed in Preamble Section IX and throughout this RTC, we have finalized regulatory provisions that include input from affected stakeholders and provided several clarifications that will establish regulatory provisions for biogas in a manner that will allow EPA to effectively oversee the program.

The commenter has more specific suggestions which are addressed in other parts of the RTC.

Comment:

One commenter requested EPA clarify that RINs/eRINs are simply financial vehicles devoid of any environmental attributes, given that the Greenhouse Gas Protocol (GHGP) has rules that severely restrict or entirely prohibit the allocation of environmental attributes (EAs) from market-based mechanisms as emissions reductions in GHG reporting due to concerns of additionality and double-counting of emissions reductions.

Response:

EPA takes no position on what the Greenhouse Gas Protocol requires or how parties' obligations under the RFS interact with those under that Protocol. The RFS operates under a distinct statutory regime that uses RINs to represent a volume of renewable fuel that has been produced from renewable biomass under an EPA approved pathway and that meets the applicable Congressionally defined greenhouse gas reduction threshold. These RINs are then used by obligated parties to demonstrate compliance with their RVOs under the RFS program. To the extent that parties choosing to participate in RFS also participate in other programs operating under different protocols, it is up to the responsible party to meet any applicable requirements independent of meeting the RFS requirements.

To the extent the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking.

Comment:

One commenter stated that EPA fails to provide any real-world examples of potential issues or concerns for the following requirements which relate to multiple RNG production facilities injecting RNG at the same pipeline interconnect:

- Proposed 80.140(b)(7) requires that the total number of RINs generated must not be greater than the total number of RINs eligible to be generated for the total volume of RNG injected by all RNG production facilities at that pipeline interconnect.
- Proposed 80.145(f)(8) requires at registration a description of how RNG producers will allocate RINs at a pipeline interconnect that also has RNG injected from other sources as part of the registration requirements.
- Proposed 80.155(e)(9) requires retention of documents showing compliance with § 80.140(b)(7).

The commenter states "EPA [does not] provide any discussion on whether such information can even be collected from non-related entities. We believe a shared injection point would be rare, and, in those cases where other sources of gas may be accepted, there would be separate meters for measuring that flow. As such, we do not believe these requirements are necessary and may be overly burdensome. EPA should not finalize these requirements."

Response:

In the NPRM and Preamble Section IX.A.4, we explained that biogas regulatory reform is necessary to avoid double-counting of RINs and allow EPA to effectively oversee the increasingly complex program as the volumes expand, and particularly when biogas can be used to produce more than just renewable CNG/LNG.[178] We proposed shared injection point provisions in 40 CFR 80.140(b)(7), 80.145(f)(8) and 80.155(e)(9) because in our experience shared injection points exist in the covered location and have the potential for incorrectly attributing RINs due to the added complication of having to allocate metered gas at an injection point across multiple RNG production facilities. Based on our experience, we are also concerned that parties are inconsistently attributing RIN generation because the previous biogas provisions did not specifically address this situation. Even if the situation of multiple facilities injecting RNG at the same interconnect is not common, based on our experience it is necessary to regulate them effectively to avoid double counting and ensure proper RIN allocation. These provisions provide additional requirements necessary to ensure RINs are generated properly, as described below:

[178] 87 FR 80693.

- RINs can only be generated for renewable fuel used for transportation purposes and the proposed 40 CFR 80.140(b)(7) ensures that RINs are not generated for RNG that is not placed on the commercial pipeline.
- Because different parties may have agreements with one another as to which facility's RNG should count towards RIN generation when the total number of RINs is limited by proposed 40 CFR 80.140(b)(7), we proposed to require in proposed 40 CFR 80.145(f)(8) that RNG producers must clearly specify at registration how RNG will be allocated when multiple parties share an injection point. This registration requirement is necessary so that EPA and auditors can oversee that the number of RINs has been generated consistent with this agreement, which is critical to avoid double-counting of RINs.
- The requirement in proposed 40 CFR 80.155(e)(9) ensures that records are kept in case the facilities are audited, which is necessary to enforce against double-counting of RINs.

Given our concerns that the previous biogas provisions do not address the potential for double counting when RNG is injected at a shared ejection point, we believe each of these provisions is necessary to ensure that RINs are generated for a given volume of RNG only once. We are therefore finalizing these provisions as proposed. Given adjustments in section numbering, the provisions proposed to be included at 40 CFR 80.140(b)(7), 40 CFR 80.145(f)(8), and 40 CFR 80.155(e)(9) are being finalized to be added to the CFR at 40 CFR 80.125(b)(7), 40 CFR 80.135(d)(8), and 40 CFR 80.145(c)(9), respectively.

11. Amendments to the RFS Program Regulations

11.1 RFS Third-Party Oversight Enhancement

Comment:

Multiple commenters supported the proposed enhancements to third-party oversight provisions.

Response:

We thank the commenters for their support.

Comment:

One commenter did not necessarily oppose strengthening the requirements applicable to independent third-party auditors and engineers but requested more time to review the changes. The commenter noted that EPA is proposing significant new registration requirements and has already indicated a concern with the availability of professional engineers and the time it takes to undergo the registration process. Any changes to existing requirements will only delay this process further.

Response:

As described in Preamble Section X.A.2, we are delaying the effective date of the RFS third-party oversight enhancements to February 1, 2024. We believe this additional time will allow professional engineers time to review and adapt to the new requirements as suggested by the commenter. The enhancements to the third-party oversight provisions are not expected to impact the availability of third-party engineering services, and if they do we believe the market will be able to respond to the increased demand with more auditors offering RFS-related services.

Comment:

One commenter recommended that site visits be required to occur when the facility is capable of producing renewable fuel (i.e., mechanically complete), instead of while the facility is producing renewable fuel.

Response:

This change would undermine the purpose of the proposed amendments because it would likely result in engineering reviews being conducted when a facility is non-operational and would not provide the regulated community and EPA with greater confidence in the production capabilities of the renewable fuel facility. We note that we are not requiring that the facility be operational for the engineering review during initial registration; i.e., the requirement that facilities be operational only applies for three-year registration updates.

Comment:

One commenter opposed the requirement that the site visit occur when the facility is operational because third-party engineers often visit multiple sites on a single trip for efficiency purposes and it would be difficult to find a time when no site is experiencing a scheduled or unscheduled shut down. Alternatively, the commenter recommended easing the burden by simply encouraging parties to make efforts to ensure the sites will be operational during the review or prohibit reviews when two or more sites in a single visit are not operational.

Response:

Although requiring site visits to occur when the facility is operational may require more planning and create logistical challenges, the number of enforcement actions EPA has taken against renewable fuel producers that generated invalid RINs, and the extent of the unlawful and fraudulent activities associated with the RFS program, raise significant concerns regarding the adequacy of the site visits that are being conducted. Requiring that site visits occur when the facility is operational will provide the regulated community and EPA with more assurances of the production capabilities of the renewable fuel facility and outweigh these logistical concerns. If a facility is experiencing an unscheduled shut down when a third-party engineer is supposed to conduct a site visit, the site visit will need to be rescheduled.

Comment:

One commenter suggested that, in lieu of a requirement that the third-party engineer provide documentation demonstrating that a site visit occurred, such as digital photographs with the date and geographic coordinates, that the third-party engineer be required to submit a signed statement verifying that the third-party engineer conducted the site visit.

Response:

We are already requiring that third-party engineers sign an electronic certification when submitting engineering reviews to EPA to ensure that the third-party engineer has personally reviewed the required facility documentation. Requiring third-party engineers to submit additional proof that the site visit actually occurred, such as a digital photograph, is beneficial because it will provide further evidence that the site visit occurred, and we do not think it imposes an undue burden on third-party engineers because cameras and smartphones capable of taking such digital photographs are readily available.

Comment:

Multiple commenters stated that EPA is proposing to require digital photographs as part of the engineer's site visit but has not provided an explanation for the need for this requirement and fails to address potential concerns regarding confidential business information (CBI).

Response:

In the NPRM and above, we explained that EPA has taken a number of enforcement actions against renewable fuel producers that generated invalid RINs. The extent of the unlawful and fraudulent activities associated with the RFS program is troubling given the roles that independent third parties play in the RFS program. The extent of fraudulent activity in some cases made it evident that third-party engineers did not actually visit the renewable fuel production facility, which could have helped identify the fraud earlier. Requiring third-party engineers to submit digital photographs to show that the third-party engineer was on site will help mitigate this problem.

Digital photographs can be taken anywhere near the facility, and we do not expect that this requirement will invoke CBI concerns because images of the facility are often readily available via the internet. Even if such pictures were potentially CBI, regulated entities may claim that information as CBI when it is submitted to EPA, and it will be handled accordingly.

The regulations also require the third-party engineer to take digital photographs of all process units depicted in the process flow diagram during the site visit. These types of photos are already routinely submitted in third-party engineering review reports. If the pictures contain CBI, regulated entities may claim that information as CBI when it is submitted to EPA, and it will be handled accordingly. Many third-party engineering review reports submitted under the current regulations contain information that is claimed and treated as CBI, and the commenters fail to explain how the photographs required under this rulemaking would risk disclosure of CBI more than photographs that are submitted to EPA under the current rules for third-party engineering review.

Comment:

Multiple commenters said that a requirement to include digital photographs may create unintended complications. Locations like the pipeline meter stations are often fenced, and the utilities can be reluctant to let third parties view—let alone take photographs of—their pipeline injection points. Furthermore, certain facilities use hazardous materials and there are OSHA or other safety restrictions that prohibit electronic equipment such as cellphones or cameras.

Response:

We recognize the commenters' concerns about potential access and safety issues with our proposed requirement that third-party engineers take digital photographs of all process units depicted in the process flow diagram during the site visit. We are finalizing a revised provision which allows the third-party engineer to submit documentation that certain locations could not be photographed due to access or safety concerns, in lieu of taking a photo of a process unit that is inaccessible. We note that if a third-party engineer makes such a claim without sufficient documentation, EPA may not be able to accept the registration submission because it will not be able to determine whether the facility is capable of producing qualifying renewable fuel, biointermediate, biogas, or RNG under the RFS program.

Comment:

One commenter opposed the proposed prohibition on third-party auditors from conducting past research, development, design, or construction for the audited party within a year of providing consulting services. The commenter also opposed the proposed prohibition on third parties that offered QAP services from offering other business services to audited parties for a period of at least one year. The commenter stated that these prohibitions were overreaching and would stifle the ability of large firms to provide QAP services because large firms often provide other services such as tax services and network consulting.

Response:

Our primary concern is the impartiality of third parties that were involved in the design or construction of a facility. We believe that a third party involved in the design or construction of a facility may be reluctant to identify potential problems associated with a facility's design or construction when conducting audits. We are therefore finalizing a narrower prohibition that only applies to third parties that were involved in the design or construction of the audited facility. We believe that the narrower finalized prohibition would address our concerns without unnecessarily limiting the pool of third parties who can qualify as third-party auditors.

Comment:

Multiple commenters opposed our proposal to disallow all personnel employed by an independent third-party auditor that is involved in a specific activity by the auditor from accepting future employment with the owner or operator of the audited party for a period of at least 12 months Commenters claimed that it may deter candidates from working for an auditor due to future job restrictions or constitute an unlawful workplace restriction in jurisdictions that have adopted "right to work" laws.

Response:

We recognize that the proposed prohibition can be more narrowly tailored to address our primary concern that third-party auditors could be unduly influenced in their QAP verification activities if they are negotiating for future employment with the regulated party. As a result, we are finalizing a narrower prohibition that only applies to auditors that are negotiating for future employment with the audited party, instead of with the regulated party. This will address EPA's concerns about the impartiality needed in third-party auditors without restricting individuals' ability to obtain future employment.

Comment:

One commenter noted that EPA proposed language at § 80.1471(b)(6) that would prohibit a third-party auditor and its contractors and subcontractors from having "performed an attest engagement under § 80.1464 for the audited party in the same calendar year as a QAP audit pursuant to § 80.1472." The commenter agrees in principle that a QAP auditor and attest service provider should not, effectively, be reviewing their own work. The commenter recommends two clarifications related to this point: (1) EPA should clarify that the prohibited attest engagements in the aforementioned circumstances are those conducted pursuant to § 80.1464(b) (applicable to RIN generation); and (2) EPA should revise the "in the same calendar year" language to read "for the same compliance period"; the timing of *when* the attest and QAP are completed matters less for independence than the *content* of the reports and other data reviewed.

Response:

We believe these proposed clarifications are consistent with the intent of our proposal and are including them in the regulations being finalized.

Comment:

Multiple commenters stated that adding more intensive requirements on third-party auditors increases the chances that there will not be enough auditors or engineers to cover all RFS participants because the supply of auditors and engineers is limited, and auditors are more likely to be conflicted out under the enhanced provisions. EPA does not provide an assessment of how its proposed changes for third-party oversight enhancement may further impact the ability to obtain engineering review services.

Response:

As explained above, we are finalizing narrower prohibitions that will make it less likely that auditors and engineers will be conflicted out of performing auditing services.

Further, although the expansion in the scope and number of regulated entities under the RFS program may increase the demand for auditing services (e.g., if more renewable fuel producers seek to have their RINs QAPed), we believe that the market will respond to increased demand and more auditors will offer RFS-related services. The number of auditors registered under the RFS program has increased recently and is still below the number of auditors registered under the California Low Carbon Fuel standard program. If demand increases, we believe that the auditors that participate in the California Low Carbon Fuel standard program but not yet in the RFS program, along with other auditors, will begin offering RFS-related services to meet demand.

The same is true of third-party engineering services. Although we are strengthening the independence requirements for third-party engineers, we do not view the enhancements to be so onerous that they will severely limit the availability of third-party engineers. If demand increases as a result of the expansion in the scope and number of regulated entities under the RFS program, we expect the market will respond and more third-party professional engineers will offer RFS-related services.

We also note that, as discussed in Preamble Section X.A, we are providing more time for third-party engineers to review and adapt to the new requirements. We believe that this additional time will further mitigate concerns related to the availability of third parties to perform services under the RFS program.

Comment:

One commenter opposed the proposed requirement that third-party engineers obtain independent documentation from parties in contracts with the producer for any co-product sales or disposals. The commenter said this will be incredibly difficult, if not impossible, for third-party engineers to accomplish, particularly for larger biofuel producers. Larger biofuel producers may supply co-products to hundreds of customers. Third-party engineers will be unable to obtain this amount of data from those parties in any reasonable amount of time. Co-products are an important part of biofuel production, ensuring that producing low-carbon fuels is economically feasible and beneficial. EPA should strike this requirement to avoid subjecting biofuel producers, their customers, and third-party engineers to this impossible data collection burden.

Response:

It is necessary for third-party engineers to obtain independent documentation from parties in contracts with the producer for any co-product sales or disposals to verify the volumes and types of renewable fuel produced at a facility. However, we recognize that requiring third-party engineers to obtain and review all records associated with the sale or disposal of co-products to every customer may pose a challenge to large renewable fuel producers that sell co-products to numerous customers. To address this, we are allowing third-party engineers to use representative sampling as described in 40 CFR 1090.1805 to verify co-product sales or disposals. We note that we already allow representative sampling of records for the RFS QAP and annual attest engagement requirements, and we believe that the use of representative sampling is also appropriate for three-year engineering reviews.

Comment:

One commenter opposed the proposed requirement that third-party engineers obtain documentation from all process heat fuel suppliers of the process heat fuel supplied to the facility. The commenter said this requirement is potentially unnecessarily burdensome and should be stricken. Some biofuel producers are serviced by dozens of process heat suppliers. It will be time-consuming and inefficient for the third-party engineer to obtain the required information. In some cases, the third-party engineer will not be able to obtain the necessary information in a timely fashion. This will needlessly prolong engineering reviews without meaningfully enhancing oversight. EPA should reconsider requiring engineers to obtain this third-party information, when doing so would be impractical.

Response:

It is necessary for third-party engineers to obtain independent documentation from process heat fuel suppliers of the process heat fuel supplied to facilities in order to verify that the facilities are complying with process heat fuel plans included in their registration information and to verify facilities are, in fact, producing renewable fuel. However, we recognize that requiring third-party engineers to obtain and review documentation from all process heat fuel suppliers may pose a challenge to facilities that are supplied by several process heat suppliers. To address this, we are allowing third-party engineers to use representative sampling as described in 40 CFR 1090.1805 to verify fuel suppliers. We note that we already allow representative sampling of records for the RFS QAP and annual attest engagement requirements, and we believe that the use of representative sampling is also appropriate for three-year engineering reviews.

Comment:

One commenter noted that the proposal indicates that EPA will require “third-party professional engineers to provide documents and more detailed engineering review write-ups that demonstrate the professional engineer performed the required site visit and independently verified the information through the site visit and independent calculations.” One commenter requested that EPA provide specific details regarding additional information requirements and new processes to ensure they are well understood. By providing clear guidance and specifications, professional engineers will be able to adapt and adhere to the new requirements quickly and efficiently.

Response:

The commenter cites preamble text, but we note that we proposed specific regulatory provisions describing the procedures professional engineers would have to follow under the proposal. While we appreciate the commenter’s desire for clear guidance and specifications regarding the proposed regulatory requirements, the commenter did not highlight specific aspects of the proposed regulatory requirements that needed clarification or further specification. This makes it difficult to respond in any specific way to the commenter’s request. Nevertheless, as we typically do for new regulatory action, we intend to engage in stakeholder outreach to discuss the implementation of the newly finalized provisions. This stakeholder outreach typically includes webinars, workshops, user guides, and written responses to stakeholder guidance.

Furthermore, we note that as discussed in Preamble Section X.A, we are delaying implementation of third-party oversight enhancements until February 1, 2024. This additional time will allow professional engineers more time to review and adapt to the new requirements as well as participate in EPA’s stakeholder outreach.

Comment:

One commenter requests that EPA provide detailed guidance in the final rule on how it would like independent verifiers to ensure they “independently evaluate and confirm the information and cannot rely on representations made by the renewable fuel producer.” This commenter relies on invoices and documentation from relevant third parties provided by the auditee. Any requirement to contact these third parties directly could pose a challenge and extend the time required to complete audits. The commenter encourages EPA to evaluate the benefits of this additional requirement versus the administrative burden.

Response:

The purpose of requiring independent parties to independently verify elements prescribed in the regulations is for the third party to rely upon their own review, analysis, and judgment to determine whether the applicable regulatory requirements are met. For example, it would be inappropriate for an independent third party to rely on certification by a renewable fuel producer that its facility is capable of producing a certain type of renewable fuel. The independent third-party engineer must conduct their own review consistent with the regulatory requirements specified in 40 CFR 80.1450, as applicable, to verify whether the facility is capable of producing a renewable fuel.

We do not mean that an independent third party cannot collect and review documentation from the audited party; in fact, in order to perform services under the RFS program, the independent third party must collect such information. We just mean that the independent third party must independently and objectively conduct its own work.

We have concerns that independent parties may rely too heavily on certifications or calculations by the renewable fuel producer in performing services under the RFS program. The extent of fraudulent activity in some cases made it evident that third-party engineers did not actually conduct their own independent verifications and instead relied solely upon representations from the renewable fuel producer that the applicable regulatory requirements were met. A requirement that holds independent third parties liable for conducting their own independent analysis is necessary to ensure that the third-party verification provisions under the RFS program function. For these reasons, we are finalizing as proposed the provision that independent third parties must independently evaluate and confirm the information and cannot rely on representations made by the renewable fuel producer.

11.2 Deadline for Third-Party Engineering Reviews for Three-Year Updates

Comment:

One commenter supported both the clarification regarding V_{RIN} calculations as well as the July 1 date for site visits for three-year engineering review updates. Another commenter also supported the July 1 site visit date.

Response:

We thank the commenters for their support.

Comment:

One commenter supported the proposed deadline of no sooner than July 1st for three-year engineering review update site visits, so long as EPA does not delay processing the submissions.

Response:

We thank the commenter for their support. The deadline should not affect the processing time of three-year engineering review updates, the timing of which is mostly a function of the accuracy and completeness of the registration submission.

Comment:

Multiple commenters opposed the requirement for site visits to be performed on or after July 1 of the calendar year previous to the deadline for submission of the three-year engineering review update due to participation in the California LCFS program, which has an August 31 verification deadline. These commenters state that third-party verifiers generally perform site visits between February and June, resulting in double site visits in the same year.

Response:

As stated in Preamble Section X.B, we are finalizing additional flexibility that will allow parties to reset their three-year update due date if they comply with the three-year update requirement earlier than allowed. We believe this flexibility will allow parties to simultaneously comply with the RFS program and CARB's LCFS verification requirements.

Comment:

One commenter stated that it is not necessary or reasonable to squeeze the site visit for a three-year review into the six months before the report is submitted.

Another commenter stated that EPA is proposing to require that third-party engineers conduct "review site-visits no sooner than July 1 of the calendar year prior to the January 31 deadline for three-year registration updates," but EPA has in the past allowed the commenter to schedule site visits a full year before the January 31 deadline. The commenter states that this has given companies needed flexibility and cost-savings while not threatening the integrity of the review. The commenter requests that EPA extend the deadline to a full year to maximize efficiency in conducting these reviews.

Response:

In NPRM Preamble Section X.B,[179] we stated that we have concerns that third-party engineers are conducting site visits well ahead of the January 31 deadline and that the renewable fuel production facilities they visited may have undergone significant alteration between the time of the site visit and the time that the third-party engineering review report is due. Such significant alteration could result in EPA accepting a registration that is no longer accurate, potentially resulting in the generation of invalid RINs.

The commenters did not explain why they believe that our concern is not valid. The commenters do not provide any evidence to support its assertion that a longer timeframe does not threaten the integrity of the review. The commenters also did not explain why it is not reasonable or cost effective to limit the site visit to within the seven months before the report is due. Given this, we are finalizing the timeline as proposed.

Comment:

One commenter suggested that EPA should defer finalizing this provision until EPA can confirm sufficient time for these site visits to occur within the new proposed timeframes.

Response:

As discussed in Preamble Section X.B, the new deadline for engineering review site visits will begin after the 2023 three-year registration update deadline (i.e., after January 31, 2024) to minimize the impact on parties that may have already arranged for engineering review site visits under the previous regulatory requirements.

[179] See 87 FR 80682 (December 30, 2022).

11.3 RIN Apportionment in Anaerobic Digesters

Comment:

Multiple commenters showed general support for the approach to apportion RINs in the NPRM.

Response:

We thank the commenters for their support, and we are finalizing the proposed approach, with modifications that are described in Preamble Section X.C and in this section. This approach will allow for the apportionment of RINs in anaerobic digesters that simultaneously convert feedstocks where at least one of the feedstocks does not have a minimum 75% adjusted cellulosic content and which are eligible for the generation of RINs for multiple D-codes.

Comment:

Multiple commenters supported the broad applicability to D5 feedstocks beyond food waste.

Response:

We thank the commenters for their support and are finalizing as proposed that parties that simultaneously process feedstocks eligible for the generation of D5 RINs other than separated food waste can utilize these RIN apportionment provisions.

Comment:

One commenter supported the use of operational data on cellulosic and non-cellulosic feedstocks being added to digesters for apportionment of D3 and D5 RINs.

Response:

We thank the commenter for their support and are finalizing as proposed the option to use operational data for apportionment of D3 and D5 RINs.

Comment:

One commenter supported that these provisions only apply to co-digestion of wastes essentially deemed cellulosic with that deemed to be non-cellulosic.

Response:

We thank the commenter for their support, and we are finalizing as proposed that these provisions only apply to parties that produce biogas in an anaerobic digester under a cellulosic pathway where two or more feedstocks are converted simultaneously and where at least one of the feedstocks does not have a minimum 75% adjusted cellulosic content.

Comment:

One commenter suggests EPA simplify and clarify the calculation process by specifying required documentation of digester operations, including frequency of measurements and data collection required for compliance.

Response:

We recognize the benefits of simplicity and clarity of the requirements. We have updated the proposed equations for apportionment in digesters to increase clarity by making the following changes:

- We added details on samples, error handling, and quality control mentioned in the standard.
- We described how composite sampling can be conducted and updated the equations to show how each sample taken for volatile and total solids measurement is used to determine biogas batch volumes.
- We specified the frequency of temperature readings to be no less frequent than every 30 minutes in a digester tank.
- We updated terminology in the regulations to specify that the residence time should be the mean residence time and specified which data should be used for determining the mean residence times.
- We specify how to handle missing data that is used to show that a digester is operating in the specified range.

These changes should address the commenter's concerns on how the data is used to show compliance with the regulations.

Comment:

During a stakeholder meeting after publication of the NPRM,[180] one commenter said that the alternative conservative value proposed in the regulations should use higher heating value and not lower heating value.

Response:

Under the RFS program, a RIN represents the energy equivalent of a gallon of denatured fuel ethanol in lower heating value. When converting renewable fuels other than denatured fuel ethanol to RINs, the regulations regarding equivalence values at 40 CFR 80.1415(b)(5) require the heating content to be in lower heating value. When apportioning the D-code of RINs in 40 CFR 80.1426(f)(3) and (f)(4), 40 CFR 80.1426(f)(7)(ii) states that higher heating value should be used. In the NPRM, we did not propose to change these requirements and intended for our

[180] See the log of stakeholder meetings in the docket to this action.

proposed regulations to be consistent with these previously established conventions; i.e., that RINs being in LHV and that RIN apportionment under 40 CFR 80.1426(f) be in HHV.

The commenter correctly pointed out that, in the proposal, we incorrectly used lower heating value to determine the default cellulosic converted fraction specified in 40 CFR 80.1450(b)(1)(xiii)(C)(*5*) of the NPRM. This is inconsistent with its use in the proposed equations in 40 CFR 80.1426(f)(3) of the NPRM and with the convention mentioned in the previous paragraph.

We have updated the default values to use the higher heating value as the commenter recommended, to make it consistent with its use to determine biogas batch volumes.[181]

Comment:

One commenter asked for clarity that this approach can apply to other pathways beyond CNG/LNG, a biointermediate, or renewable electricity.

Response:

This approach can apply to any biogas-derived renewable fuel produced from biogas that originates in an anaerobic digester. We have adjusted language in 40 CFR part 80 subpart M and subpart E to make it clear that it can apply to other processes. We intend for this to apply broadly to all relevant existing and new fuel pathways.

Comment:

One commenter asks that EPA confirm that RIN generation will not require chemical testing when cellulosic ethanol and other forms of ethanol are processed together to make ATJ SAF.

Response:

The RIN apportionment approach we are finalizing in this rule is limited in scope to biogas that is produced in anaerobic digesters that simultaneously process cellulosic and non-cellulosic feedstocks, so it would not apply directly to the act of simultaneously processing cellulosic and non-cellulosic ethanol. For this situation, the provision in 40 CFR 80.1426(f)(3) and (4) would apply, as applicable. If a facility is subject to 40 CFR 80.1426(f)(4), they could choose to determine RIN volumes using either method 40 CFR 80.1426(f)(3)(i)(A) or (B). The latter option involves chemical testing. So while not required, chemical testing is an option facilities can choose in order to determine RIN volumes.

The volatile solids and total solids testing described in this section would be required for digester feedstocks if biogas produced in anaerobic digesters that involve simultaneous conversion is converted to the ethanol that is used to make ATJ SAF.

[181] See "Final calculation of cellulosic converted fraction values from biochemical methane potential" in the docket to this rule.

Comment:

Multiple commenters said that 40 CFR 80.105(k)(4) and 80.155(b)(5)(ii) are confusing and appear to prohibit municipal wastewater plants from receiving any feedstock which is less than 75% cellulosic. They were concerned that this would preclude co-digestion of food waste which is counter to the objective of this part of the proposed regulation. They recommend either deleting these sections or the words "municipal wastewater treatment facility digester" from them.

Another commenter stated that EPA did not provide adequate reasoning for 40 CFR 80.105(k)(4) and therefore cannot finalize this provision.

Response:

The intent behind the requirements in 40 CFR 80.105(k)(4) and 40 CFR 80.155(b)(5)(ii) was to ensure that digesters that qualify as municipal wastewater treatment plant digesters, agricultural digesters, and separated MSW digesters operate entirely under row Q of Table 1 to 40 CFR 80.1426 and do not add non-qualifying or non-cellulosic feedstocks and generate D3 RINs for feedstocks that did not have an adjusted cellulosic content of at least 75%. However, these revisions do not preclude the participation of anaerobic digesters at municipal wastewater treatment facilities in the RFS program or prevent them from generating D3 RINs. Our intent for digesters that simultaneously convert both cellulosic and non-cellulosic feedstocks, regardless of their physical location next to a farm or wastewater treatment plant, is that they would qualify as an "other waste digester" under Row T and Q in Table 1 to 40 CFR 80.1426, as applicable, and would have to use the mixed digester provisions to apportion RINs based on the cellulosic and non-cellulosic feedstocks.

In the NPRM, we explained that the biogas regulatory reform provisions are intended to ensure adequate oversight.[182] These provisions add a level of oversight to make it obvious that municipal wastewater treatment facility digesters only include feedstocks with an average adjusted cellulosic content of at least 75%. We believe this is important to specify because we had concerns under the previous biogas regulatory provisions that wastewater treatment facility digesters had significant quantities of non-cellulosic feedstocks fed into them but were still generating 100% cellulosic RINs for the resulting biogas. However, we did not intend that 40 CFR 80.105(k)(4) and 40 CFR 80.155(b)(5)(ii) would preclude digesters located at wastewater treatment plants from accepting non-cellulosic feedstocks and apportioning RINs appropriately, since those digesters would be registered under our program as other waste digester. To reiterate, a digester at a wastewater treatment facility can apportion RINs according to the provisions set out here even with the proposed 40 CFR 80.105(k) and 40 CFR 80.155(b)(5)(ii) because the digester would be registered as an 'other waste digester' and not a 'municipal wastewater treatment plant digester.'

We recognize that the proposed regulations at 40 CFR 80.105(k)(4) and 40 CFR 80.155(b)(5)(ii) may have confused stakeholders. This is due, in part, to not having a definition of a municipal wastewater treatment plant digester in the regulations. We have added a definition for municipal

[182] 87 FR 80692-80693.

wastewater treatment plant digester to clarify that these provisions do not apply to facilities that properly apportion RINs.

We are finalizing as proposed the provisions proposed as 40 CFR 80.105(k)(4) and 40 CFR 80.155(b)(5)(ii), since the commenter did not explain how removing these provisions would lead to an effective program and since these provisions do not exclude waste digesters at municipal wastewater treatment plants from simultaneously converting cellulosic and non-cellulosic feedstocks.

Comment:

Multiple commenters raised concerns that the proposed option for cellulosic converted fraction (50% of BMP) is too conservative.

Multiple commenters suggested higher values of the BMP should be used. One commenter suggested that the formula to be increased to 75%. Nine other commenters suggested 80%.

One commenter stated that it is their understanding that EPA proposed that 50% of the gas from manure is counted toward D3 RINs with the remainder obtaining D-5 RINs.

Commenters argued that higher values would provide significant valuation for co-digestion to justify the product development at smaller firms and cities. Some commenters stated that a higher value would still be conservative.

Multiple commenters stated that the sources EPA cited in the NPRM provide evidence towards increasing the value.

One commenter said that American Biogas Council found, when comparing ideal laboratory biochemical methane potential (BMP) to industrial scale production, scientific literature, and years of dairy digester data (adjusted to temperature and hydraulic retention time limits proposed by EPA), that BMP from industry digesters is approximately 80-100 percent of the calculated laboratory values. Multiple commenters stated that the correlation between BPM and digester operational data is between 81-97%.

One commenter submitted operational data that the commenter claimed as CBI showing a correlation between BMP and cite operational data in an attempt to justify a higher cellulosic converted fraction.

One commenter said that no functioning digester facility will select these values, as the lost revenues are too significant.

One commenter recommended as an alternative using the literature value combined with a maximum amount of D3 gas that can be produced based upon D3:D5 feedstock ratios into the digester.

Response:

In the NPRM, we anticipated that some biogas producers would not want to invest in obtaining the operational data needed to obtain a facility-specific cellulosic converted fraction value, so we provided conservative values that producers could use at their discretion and still be able participate in the RFS program. We chose a conservative fraction (50%) to virtually guarantee that cellulosic RINs were not generated for non-cellulosic feedstocks in order to ensure consistency with Clean Air Act and EPA regulatory requirements. We intended the conservative value to be near the lower limit of digester performance, and that facilities operating more efficiently could apply for a higher value separately. We based the proposed values on published biomethane potential (BMP) [183] measurements and a comparison between BMP and actual digester biogas production as discussed in the NPRM.[184]

We sought comment on these proposed values, asking that comments include information about the underlying data, discussion of why the underlying data is representative (for example, by describing the process by which data was selected), and how the converted fraction was derived from operational data, along with a list of operational conditions on which the data was based.[185]

Some commenters misinterpreted the proposal. We proposed that, under the alternative conservative converted fraction option, 50% of the BMP can qualify for D3 RINs not that 50% of the biogas produced in the digester from the manure can qualify for D-3 RINs. We expect more than 50% of biogas produced from manure to be able to count towards D3 RINs when the conservative value is used, since BMP is typically higher than amount of biogas actually produced in digesters (see Preamble Section X.C for more information on this). For example, the BMP value used in this rulemaking for bovine manure is 4,154 Btu HHV of biogas per pound volatile solids of manure and the conservative conversion factor we are finalizing is 2,077 Btu HHV of biogas per pound volatile solids of manure (which is 50% of the BMP). A facility that produces at 70% of the BMP would produce around 2,908 Btu HHV of biogas per pound volatile solids of manure. In this scenario, the conservative default value would be 71% of the manure production, not 50% that the commenter suggested.

In the NPRM, we cited a study that recommended facilities be designed with a capacity 10-20% less than the BMP, and we explained why our goal, to ensure renewable fuel is produced consistent with CAA requirements, is different than the goals around designing a facility, which often is built with extra capacity. We explained that our concern with the proper classification of renewable fuels would necessitate lower default value than the paper recommended.[186] Multiple comments referenced the paper we cited in the NPRM to justify a higher BMP value but did not provide a rational based on the different goals that we described in the NPRM.

While commenters explained how using a higher value for the conservative of cellulosic converted fraction would help project development, they did not explain how this higher value

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[183] Biomethane potential (BMP) is a measurement of the maximum biogas that can be produced from a feedstock through anaerobic digestion.
[184] 87 FR 80684.
[185] 87 FR 80685.
[186] 87 FR 80685.

would prevent cellulosic RINs from being generated for non-cellulosic feedstock consistent with Clean Air Act and EPA regulatory requirements. We are not finalizing a higher value because we are not confident that renewable fuel would be correctly classified as cellulosic if a higher value of the cellulosic converted fraction were used. If a project developer believes the default converted fraction value is not appropriate, parties looking to develop projects may apply for a site-specific cellulosic conversion value.

Commenters that presented operational data were not able to adequately show how that data is representative of an industry as a whole (for example by randomly selecting digesters of a particular type across the country and reporting response rates of such digesters to be included in the data). Without representative data, it is not possible to adequately confirm that the data reported can be extrapolated to the whole industry. We note that under the provisions finalized in this action, these commenters would be able to establish a different BMP based on operational data at the facility level so long as such operational data adhered to the applicable regulatory requirements.

Commenters that presented data argued that the average value they presented should be used as the conservative value in the regulations. We intended the conservative value to be near the lower limit of digester performance, and that facilities operating more efficiently can apply for a higher value separately. Taking the average value of non-representative data is not a conservative approach and would likely result in the generation of D3 RINs for non-cellulosic feedstocks.

Regarding commenters that presented other biomethane potential measurements for consideration, we requested operational data for use in re-evaluating these values to reduce the risk of selecting the highest value from operational biomethane potential measurements to use as the basis for a conservative estimate. The commenters did not explain in sufficient detail why the biomethane potential value that they suggested we use as the basis for our conservative value is more representative and accurate than the value used in the NPRM. Given our concern about using an unrepresentatively high value from biomethane potential measurements and the lack of data showing that the biomethane potential recommended by commenters is representative of the country as a whole, we are not updating the calculations based on commenters' suggested biomethane potential measurements.

In light of this discussion we are finalizing the conservative values using 50% of the biomethane potential measurements proposed in the NPRM.

Comment:

One commenter recommended we create a standalone apportionment section stating that the proposed regulations are difficult to follow.

Response:

We recognize that there was some confusion for the biogas requirements for these RIN apportionment provisions. Some of the provisions, such as measurement, were in subpart E and some, such as RIN apportionment and registration, were in subpart M. To make it easier for stakeholders to understand the regulations, we have moved the proposed apportionment provisions for the co-digestion of feedstocks in an anaerobic digester to produce biogas from the general RFS subpart at 40 CFR part 80, subpart M into the specific subpart for biogas-derived renewable fuels at 40 CFR part 80, subpart E. We also moved the default conversion factor values from the registration section (proposed at 40 CFR 80.1450(b)) to 40 CFR 80.105 where the equations in which they are used are located. We believe this consolidation will help the commenters and other stakeholders more easily read, understand, and comply with the regulatory requirements.

We did not create a standalone section for RIN apportionment since we believe that given the complexity of the various RFS pathways, it may be confusing for stakeholders if we placed all requirements for each specific type of pathway in a single section. We believe that the adjustments made in the final rule are sufficient to improve the readability of the regulations without creating an exception to the structure of the regulations that may create more confusion than it resolves.

Comment:

One commenter suggested that the apportionment of RINs should be based on a value from an average of the mass fed to the anaerobic digester.

Response:

The commenter does not specify how or why an average should be obtained. We are clarifying in our rule that parties may take composite samples of the cellulosic feedstock which we believe would more likely represent the average volatile solids content than single samples. We believe this incorporates the commenter's suggestion.

Comment:

One commenter mentioned inaccuracies and high costs with measuring volatile solids on food waste.

Response:

We did not propose and are not finalizing a requirement to measure volatile solids of the non-cellulosic feedstocks in order to apportion RINs for the anaerobic digesters. Food waste does not need to be measured for volatile solids, regardless of whether a facility uses the conservative converted fraction or specifies operating conditions.

Comment:

One commenter recommended that parties be able to identify operational parameters based on the minimum requirements in 40 CFR part 503 for municipal sludge treatment for baseline biogas production.

Response:

The requirements for 40 CFR part 503 are intended to reduce the spread of disease, which is distinct from the goal of accurately determining biogas yields. The commenter did not explain why operating within 40 CFR part 503 requirements would not lead to variation in biogas yields. If the provisions are not sufficient to ensure biogas production, cellulosic RINs would likely be generated for non-cellulosic fuel. Given that the commenter did not provide information to support such an approach and such an approach would likely result in the generation of D3 RINs for non-cellulosic feedstocks, we are not finalizing an allowance for facilities to meet 40 CFR part 503 in lieu of the operational parameters described in the NPRM.

Comment:

One commenter stated that wastewater treatment plant digesters should be able to calculate D-3 RINs based on 15 scf of biogas per pound of volatile solids destroyed instead of cellulosic volatile solids fed, since this is the metric typically used in the wastewater treatment industry and is already measured.

Response:

We generally support reducing regulatory burden by utilizing measurements already taken by industry. Those measurements, however, must be able to show that the renewable fuel meets the requirements set forth in the CAA, which in this case includes that cellulosic biofuel is derived from cellulose, hemicellulose, or lignin. Since a “volatile solids destroyed” measurement would include volatile solids from all feedstocks placed in a digester, it is not necessarily an accurate proxy for the amount of biogas that came from cellulosic feedstocks. Based on what the commenters suggested, a facility that processes 95% food waste and 5% wastewater sludge would get the same number of D3 RINs as a facility processing 5% food waste and 95% wastewater sludge, if they have the same volatile solids destruction. There is significant risk in the former case that D-3 RINs would be generated for fuel that is not derived from cellulose, hemicellulose, and lignin, running counter to the statutory requirements for cellulosic fuels.

Comment:

One commenter says that food waste should be eligible for D3 RIN, since it is an inherent component of sewage and solids.

Response:

We did not propose changes to pathways, including the provisions for the predominantly cellulosic determination of feedstocks. Given this, a change to allow food waste to be eligible for D3 RINs is outside the scope of this rulemaking. For more information on the pathway determination for food waste, see 79 FR 42140 (July 18, 2014).

Comment:

One commenter suggests EPA provide example calculations of how a RIN generator would calculate the two options for D3 and D5 separation, so that RIN generators can reach an accurate and informed decision.

Response:

We believe that working with stakeholders to ensure a complete and common understanding of EPA regulations is important to support compliance with the applicable RFS regulatory requirements. After completing the last RFS rule in 2022, which included regulations allowing for the use of biointermediates, EPA held a webinar for the public to explain the requirements and implementation of biointermediates. Similarly for this action, we intend to conduct stakeholder outreach to update stakeholders on the new requirements, including example calculation on how to apportion D3 and D5 RINs.

Comment:

One commenter requested clarity of the registration, recordkeeping, and reporting requirements for separated food waste when received for co-digestion at wastewater resource recovery facilities (WRRF). The commenter strongly recommended that for registration and reporting EPA make clear that only the types of separated food waste and the types of facilities from which it comes need be reported and not specific locations or individual records, consistent with 40 CFR 80.1450(b)(1)(vii)(B) for separated food waste and with 40 CFR 80.1479(e).

Response:

All registration, recordkeeping, and reporting requirements that apply to facilities that use separated food waste as a feedstock to produce renewable fuel also apply to biogas production facilities that digest or co-digest separated food waste. These provisions are necessary to ensure that the feedstock is renewable biomass consistent with Clean Air Act requirements. We are equally concerned that non-qualifying feedstocks, such as palm oil, may be added to anaerobic digesters, biodiesel production facilities, and renewable diesel production facilities. The commenters do not explain why parties operating anaerobic digesters at WRRFs should be exempt from the requirements placed on other facilities that use separated food waste in a different process.

Comment:

One commenter believes that initially limiting the mixed feedstock projects to pathways producing renewable CNG/LNG is reasonable, but EPA should have a plan to expand beyond this scope in the coming years.

Response:

In the NPRM,[187] we explained that the proposed provisions would apply to biogas-derived renewable fuels, RNG, and renewable fuels produced from RNG used as a feedstock, and we sought comment on whether the approach should be more limited (such as applying it only to renewable CNG/LNG). The commenter did not state whether they preferred a limited approach more than the proposed broader approach nor did the commenter provide the information we requested in the NPRM: "Commenters should provide examples of how expanding or restricting the use of these proposed changes beyond pathways for the production of renewable CNG/LNG or renewable electricity from biogas produced in anaerobic digesters would be beneficial or problematic, using examples of specific production pathways and processes."[188]To further clarify our intent that the mixed digester provisions apply to more than just renewable CNG/LNG, we are finalizing the mixed digester provisions in the new 40 CFR part 80, subpart E. Should we allow for the use of more biogas-derived renewable fuels in the future, we have drafted the regulations in a manner that would allow for them to be used for those new fuels.

After both EPA and regulated entities have experience with this program, we hope to look into how these provisions can apply to fuel production processes other than biogas-derived renewable fuel, including what process characteristics may be necessary (see Preamble Section X.C for a discussion of these characteristics and how they align with the assumptions built into the apportionment equations) and how parties can show the processes have these characteristics. We believe it is appropriate to only apply these provisions to biogas-derived renewable fuels at this time because we have only received requests for this type of provision for producing biogas and because we want to ensure that the provisions are not used when they would overestimate cellulosic fuel production, which is more likely if the equations were allowed to be used more broadly.

Comment:

One commenter says "[T]he requirement to measure both percent total solids and volatile solids daily [is] overly burdensome in many cases. The ratio of total solids to volatile solids will remain consistent for many D3 feedstocks, such as manure or agricultural crop residues. The prescribed test protocols require standard lab equipment, with the volatile solids protocol requiring somewhat specialized equipment like a muffle furnace. Not all facilities will have this equipment, or sufficient resources to perform the testing daily, and will rely on outside laboratories which could become expensive."

The commenter proposed the following alternatives:

- Allow preparation of a weekly composite sample for volatile solids testing that maintains the sampling frequency but reduces the number of tests which must be run by a laboratory.
- For feedstocks with a consistent composition, allow for weekly or bi-weekly volatile solids analysis, given that the frequency of sampling is documented in their Engineering

[187] 87 FR 80685.
[188] 87 FR 80685.

Review, and that entities not change their sampling protocol or frequency without approval to avoid preferential selection of data or additional sampling to dilute high or low values.

- A third option would be to allow entities to provide data to support a sampling and testing frequency for both volatile and total solids, where feedstocks that can demonstrate stable results of a significant period can qualify for reduced testing frequencies. This data and the sampling protocol would be reviewed and documented through the Engineering review process.

Response:

To reduce the burden identified by the commenter, we are finalizing regulations to allow for composite sampling in accordance with standard method (SM 2540) description of sample storage. This prevents the need to test the total and volatile solids daily, which the commenter said was overly burdensome in many cases. We note that the standard does not allow storage of samples for a week, so weekly composite sampling would not be possible. Given that the commenter did not explain why weekly testing would still be accurate, we are requiring that sample storage comply with the SM 2540.

We also are not specifying a different sampling frequency for total solids and for volatile solids. The commenter did not present data showing consistency in the ratio of total solids to volatile solids, so we could not determine if measuring one of those quantities and extrapolating to another using less frequent testing of the ratio would be sufficiently accurate to avoid the generation of cellulosic RINs for non-cellulosic feedstocks. Given that the testing is being relied upon for RIN generation and that RFS has not overseen this measurement used for RIN generation before, we believe that allowing less frequent samples would require additional regulatory controls to ensure that cellulosic RINs were not generated from non-cellulosic feedstocks. In the future with more time and experience administering the program, we may revisit this allowance.

Given the concern about sampling frequency, we are specifying in the regulations how missing volatile solids and total solids data should be accounted for. Specifically, we are specifying that missing data would only invalidate cellulosic feedstock for the day in which data was missing and not for the entire batch. This means that all biogas produced for the day in which volatile solids and total solids data are missing would be eligible for non-cellulosic RIN generation. This change reduces the consequence of missing a sample, reducing the impact on the biogas producer and parties that use such biogas to produce biogas-derived renewable fuel or RNG.

Comment:

One commenter said that the requirement for the Cf to equal zero if a digester's operating conditions go outside the prescribed range to be unreasonable and punitive. The commenter said that if the digester temperature drops by one degree below the prescribed range, or if there is increased flow to the digesters for a brief period, the proposed text suggests that no D3 RINs can be generated for the full month. The commenter proposed the following alternatives:

- An option to calculate the D5 biogas production daily within a month, where Cf is set to zero on any days where the operating conditions went outside the prescribed range.
- The ability to calculate more than one conversion factor for a digester system to correlate with different sets of operating conditions, where the appropriate Cf can be applied as needed.
- An option to apply a factor for minor temperature deviations, where production is reduced by an amount commensurate with the temperature drop.
- The ability to use one of the prescribed default conversion factors in the regulations, provided the operating conditions for those values are met.

Response:

Based on the commenter's statement, we realize that our proposal would make an entire month ineligible for cellulosic RINs if the operating conditions go outside the range for a short period of time. Our intent in these provisions was to ensure renewable fuel is assigned to the proper category based on the feedstock from which it originates. Our intent was not to overly penalize short deviations in operations. We are finalizing an adjustment to the equations for determining biogas energy in an anaerobic digester for determining volumes of biogas batches to incorporate the first alternative proposed by the commenter. This alternative is most appropriate, relative to the other options provided by the commenter because it applies equally to those using their own conversion factors and the conservative default ones, the conversion factor has data to support its value, and the singular value allows for the volumes to be more easily overseen by third party auditors and EPA.

Note that we have renamed feedstock energy to biogas energy to be more specific in the equations and moved the equations from 40 CFR part 80, subpart M to 40 CFR part 80, subpart E as discussed in a previous response in this subsection.

Comment:

One commenter recommends EPA clarify the types of ranges and calculations which are acceptable to avoid confusion. For example, the proposed default conversion factors for manure and wastewater sludge are valid for continuously operated digesters above 95 degrees Fahrenheit with hydraulic and solids residence times greater than 20 days. The commenter asked whether biogas producers would be able to prescribe ranges this wide for their calculated conversion factors. The commenter also asked whether monthly average temperature would be acceptable when calculating the operating conditions to demonstrate conformance or whether the daily average must be within the prescribed range.

Response:

Due to differences in facility historical operations, geographical location, feedstocks, and measurement capabilities, ranges of operating conditions and conversion factors must be decided on a case-by-case basis. For example, a plug-flow underground digester with residence times exceeding 150 days might have biogas production that is less sensitive to weekly temperature fluctuations than a continuously stirred digester operating with a 16-day residence time. While a monthly average temperature might be appropriate for the former, it would be less appropriate for the latter. The time range (e.g. hourly, daily, or monthly) necessary to show compliance would vary based on the type of facility and must be decided on a case-by-case-basis.

To help clarify for the commenter what we would like to use to evaluate the acceptable ranges in our case-by-case evaluation, we are primarily interested in historical data showing the distributions of operating conditions for which the digester has operated, the distribution of properties of the feedstocks input into the digester and the distribution of properties of the biogas produced in the digester. We also expect to see an explanation demonstrating how no biogas generated from non-cellulosic feedstocks could be assigned to a biogas batch with a D-code of 3 or 7. This demonstration would be necessary to ensure that the cellulosic converted fraction is representative, using information about the operating conditions feedstocks, ranges, seasonality of operation, and other factors. We have updated the regulations to specify the demonstration.

Comment:

One commenter stated "[T]he regulations do not provide an option for the case where historical operations on the D3 feedstock alone do not align with the operating conditions when D3 and D5 feedstocks are mixed. If a new feed is being added to a digester system, it is possible that one or both of the liquid and solids retention times will be different."

The commenter recommended the following solutions:

- Allowing broad operating condition ranges that cover similar cases.
- Making the available default conversion factors more reasonable.
- Allowing for actual data combined with theoretical factors where a full set of actual data is not available (e.g. actual data with factor for higher or lower residence times).

Response:

Regarding the first part of this comment, we recognize that for some facilities it may be difficult to provide historical operations data that would be the same after D3 and D5 feedstocks are mixed. That is partially why we proposed a conservative conversion factor that would allow for co-digestion without requiring operations data that was impractical to obtain. This option exists for the stakeholder to use, and we are finalizing as proposed the option that a facility may use a conservative conversion factor instead of obtaining or generating facility-specific operations data, which provides an option in the situation that the commenter requested.

Regarding the potential solutions recommended by the commenter, the first and third potential solutions were unclear and therefore were not incorporated in the final rule. The commenter did not explain how the regulations could be structured to incorporate these potential solutions while providing sufficient oversight. Specifically, if these solutions were adopted, EPA would be tasked with making a decision about a value outside of the range for which EPA has data. The second potential solution was commented by multiple parties and was not incorporated as discussed earlier in this section.

Comment:

One commenter stated: "In 2010, EPA deemed separated food waste to be composed entirely of cellulosic materials (40 C.F.R. § 80.1426(f)(5)(i)(A)) and established a formula for calculating RINs for separated MSW at landfills (40 C.F.R. § 80.1426(f)(5)(v)). EPA is not proposing changes to these regulations (except to reflect new terms) and should make clear that none of the new regulations are intended to change treatment of these feedstocks. We understand the term "feedstock" to be those as listed in Table 1 to 40 C.F.R. § 80.1426 (e.g., biogas from landfills) and that EPA is not adding new testing requirements for separated MSW or yards wastes, except to the extent there may be codigestion in other waste digesters."

Response:

We note that 40 CFR 80.1426(f)(5)(i)(A) refers to separated yard waste. EPA has not classified separated food waste as entirely or predominantly cellulosic. It is unclear what the commenter was intending with that statement.

We are not adding new testing requirements for separated MSW or yard wastes except to the extent there may be co-digestion in other waste digesters that were not in the proposal.

Comment:

One commenter states "with regard to registering projects that will codigest cellulosic and non-cellulosic feedstocks, the commenter is concerned that projects will be constrained by confidential business information and unable to provide individual sources and weights. We are supportive of providing broad information that would respect such considerations. For example, when registering a project codigesting biosolids with food waste, the project could share the general category of food waste and the type of processor such as pre consumer bin separated or post-consumer fats, oils, and grease (FOG).

Response:

Entities registering to use separated food waste as a feedstock must submit separated food waste plans as described in 40 CFR 80.1450(b)(1)(vii)(B)(1). This requirement does not require information on individual sources and weights, which should address the commenter's concern. Note that we did not propose and are not finalizing changes to this requirement.

There are also recordkeeping requirements associated with separated food waste. Since the recordkeeping provisions are essential to ensuring that RIN-generating renewable fuel is produced from renewable biomass, as described in the NPRM,[189] the records need sufficient details to show that the feedstock qualifies. The commenter does not explain how the broad category approach which they suggest would provide sufficient detail to verify that the feedstock is, among other things, a waste as opposed to virgin vegetable oil.

[189] 87 FR 80700.

11.4 BBD Conversion Factor for Percentage Standard

Comment:

Stakeholders who commented on our proposal to increase the conversion factor in the equation for calculating the percentage standards for BBD were generally supportive of our approach. One stakeholder suggested that we should base the factor on projections of biodiesel and renewable diesel from EIA. Another said that we should also update the conversion factor in the future as needed.

Response:

We have not used the forecasts of biodiesel and renewable diesel consumption from EIA to project the conversion factor because EIA's projections do not include the influence of the applicable standards for 2023–2025 that we are establishing in this final rule. However, we have updated our analysis to include additional data. We may consider updating the conversion factor in the future if it is deemed appropriate to do so.

Comment:

One commenter recommended that EPA wait until 2024 to decide whether to change the BBD conversion factor, consistent with the commenter's request that EPA revise its implementation of the BBD standard in 2024 to be a biodiesel-only standard.

Response:

As discussed in RTC Section 4.5, we are declining to make the changes to the BBD standard requested by the commenter. As such, there is no reason for EPA to delay a decision or implementation of the revised BBD conversion factor, and we have applied the new factor to the calculation of the BBD percentage standards for 2023-2025.

11.5 Flexibility for RIN Generation

Comment:

One commenter supported the proposed modification of 40 CFR 80.1426 to provide that renewable fuel producers “may” generate RINs if they produce renewable fuel meeting RFS requirements, rather than stating that they “must” generate RINs. This change would provide flexibility for rare circumstances in which it may be impractical or inappropriate to generate RINs.

Response:

We thank the commenter for their support.

Comment:

One commenter noted that EPA had proposed to amend 40 CFR 80.1426(b) to allow domestic renewable fuel producers to generate RINs upon production, exporting some volumes to non-covered locations, and retiring RINs associated with the exported volumes. The commenter stated that foreign producers deserve the same flexibility.

Response:

The changes to 40 CFR 80.1426(b) that are being finalized apply equally to foreign and domestic renewable fuel producers.

Comment:

One commenter noted that EPA’s proposal to clarify that 40 CFR 80.1426 does not require RIN generation for all production of renewable fuels, allowing parties to opt-out of the RFS program. EPA should allow the same flexibility for RNG.

Response:

The changes to 40 CFR 80.1426(b) that are being finalized apply to RNG, and as discussed in RTC Section 10.6, we have modified the related definitions under the biogas regulatory reform provisions to further clarify that products produced from biogas outside of the RFS program are not subject to the regulatory requirements. However, we note that such gas would not be eligible to generate RINs.

11.6 Prohibition on RIN Generation for Fuels Not Used in the Covered Location

Comment:

One commenter supported EPA's proposed changes to § 80.1426 which clarify that foreign RIN generators should only generate RINs on biofuels intended to be shipped to the United States, stating that this would put foreign RIN generators on square footing with domestic producers and limit the potential for undesirable feedstocks to inadvertently enter the program.

Response:

We thank the commenter for their support.

Comment:

One commenter stated that the current regulations provide producers, regardless of location, the same flexibility to generate RINs on renewable fuels and retire RINs for any volumes of fuel not used in the United States. The commenter further claims that EPA's proposal to amend 40 CFR 80.1426(c) and 80.1431 is not a "clarification," but a substantive change to the rule that eliminates foreign producers' flexibility to enter the U.S. market. The commenter claims that this change, coupled with its suggestion to increase by 2900% the bond amount posted by foreign RIN generators and eliminate one of the two methods of bond payment, makes it less likely that foreign producers would supply American businesses with renewable fuels.

The commenter noted that foreign producers must generally comply with all RFS requirements applicable to domestic producers of renewable fuel and satisfy additional obligations that apply only to foreign producers (e.g., to designate each batch of renewable fuel as "RFS-FRRF" at the time of production, segregate finished fuel, and submit a third-party certification to the producer and EPA). 40 CFR 80.1466(c)(1) and (d). At the time of production, a foreign renewable fuel producer may not know the ultimate destination of its product. Accordingly, to participate in EPA's RFS program, a foreign producer must comply with all RFS requirements, including designation as RFS-FRRF at the time of production and segregation in a finished product in a tank with other batches of RFS-FRRF, until a decision is made regarding the final disposition of the renewable fuel and the RFS-FRRF is loaded onto a vessel, at which time RINs can still be generated on the batch of RFS-FRRF exported to the U.S. This RIN generation practice complies with the regulations and does not pose a risk of RIN double counting or RIN fraud as EPA sees all RIN transactions in EMTS.

In contrast, the RFS regulations do not prohibit domestic renewable fuel producers from generating RINs upon production, exporting some volumes to non-covered locations, and retiring RINs associated with the exported volumes. To assure equal application of the rules, EPA should be careful not to limit foreign producers' ability to produce renewable fuel consistent with the RFS program and to later generate RINs for the volumes of renewable fuel imported into the United States.

Response:

As explained in the NPRM (87 FR 80687), the amendments do not change the existing requirements but instead reiterate that parties cannot generate RINs for renewable fuel unless it was produced for use in the covered location. One of goals of the RFS program is to increase domestic consumption of renewable fuels, so it stands to reason that RINs can only be generated on fuels that are produced for use in the covered location. The existing requirements at 40 CFR 80.1466 which apply to foreign renewable fuel producers and importers are needed to oversee compliance of companies located outside of the United States; they are not designed to allow foreign renewable fuel producers to generate RINs for fuel produced for use outside of the United States.

There are several existing mechanisms available to address the commenter's concern that a foreign renewable fuel producer may not know the ultimate destination of its product at the time of production. First, the renewable fuel producer could dedicate storage tanks for volumes that are produced for use in the covered location and divert new volumes to other storage tanks when market demands shift. Second, if RINs are generated on a batch of renewable fuel that is ultimately sent to a non-covered location, the foreign renewable fuel producer can seek to address this through the remedial action process. Lastly, if the U.S.-based importer is the RIN generator then RINs will only be generated on volumes sent to the covered location.

Further, the regulations afford both foreign and domestic renewable fuel producers flexibility to generate RINs on renewable fuel produced for use in the covered location. Because not all renewable fuel produced in the United States will be used in the covered location, the regulations include requirements for renewable fuel for which RINs were generated that is subsequently exported, but those provisions require producers and distributors to assume exported volumes consist entirely of cellulosic biofuel or biomass-based diesel if any portion of that fuel includes cellulosic diesel. See 40 CFR 80.1430(c).

11.7 Separated Food Waste Recordkeeping Requirements

Comment:

One commenter suggested that EPA modify the annual attest requirement for non-QAP renewable fuel producers to add a requirement to audit a representative subset of feedstock suppliers instead of EPA's proposed alternative approach. The commenter further states that this would not require changes to registrations and puts the burden of recordkeeping on the feedstock aggregators, protecting their competitive advantage while maintaining the integrity of the program. Another commenter also suggested that, as an alternative to EPA's proposal, the auditor for annual attest engagements could request access to the separated food waste records and review.

Another commenter also suggested, as an alternative to EPA's proposal, annual audits as part of each renewable fuel producer's attest engagement.

Response:

The annual attest engagement provisions for the RFS program specified at 40 CFR 80.1464 are not an adequate substitution for the alternative recordkeeping requirements, which utilize the RFS's QAP program to ensure that feedstocks qualify as renewable biomass. The attest auditors lack the technical expertise to perform QAP audits and verify critical elements of the alternative. Annual attest engagements are performed by Certified Public Accountants or by Certified Internal Auditors. In general, auditors that are conducting attest engagements would not have the expertise to determine whether feedstocks being used qualify as separated food waste or biogenic waste oils/fats/greases. QAP auditors are required to have a professional engineer who has work experience in chemical engineering or in renewable fuel production. Furthermore, one of the conditions of using the alternative recordkeeping requirements is that the feedstock aggregator's facility be visited by an independent third-party auditor. Attest auditors lack the appropriate engineering background to effectively conduct site-visits consistent with EPA regulatory requirements. QAP auditors have the necessary technical expertise which attest auditors lack to conduct audits of feedstock aggregator facilities and make feedstock qualification determinations.

While, as one commenter mentioned, using attest audits would not require changes in registrations, puts the burden of recordkeeping on the feedstock aggregators, and protects their competitive advantage, it does not maintain the integrity of the program due to the reasons discussed in the previous paragraph.

Comment:

One commenter suggested, as an alternative to EPA's proposal, allowing third-party entities to create, refine, and maintain aggregated, anonymized evaluative tools for identifying when to perform a targeted audit of documents submitted by a UCO collector or aggregator to ensure compliance with 80.1454(d) and 80.1454(j).

Commenters suggested that, as an alternative to EPA's proposal, EPA adopt a risk-based assessment approach for the auditing of feedstocks and stated that this approach provides reasonable assurance with regard to feedstock qualification while not requiring that every feedstock supplier submit to an extensive, costly, and time-consuming regulatory audit process. The commenter suggested requiring audits of a representative sample of feedstock suppliers such as under the RFGSA program.

One commenter said that it is infeasible for a third party to review hundreds of thousands or millions of records a year

Response:

It is unclear what commenters are suggesting when they refer to "aggregated, anonymized evaluative tools for identifying when to performance a targeted audit" or a "risk-based assessment approach." The commenters also fail to explain how such an approach would work or how it could more effectively identify potential fraud or invalid RIN generation versus the random sampling approach utilized under the RFS program. The commenters do not identify the relevant criteria that EPA should specify to establish a risk-based assessment approach, nor does EPA know what they might be. EPA is also concerned about relying solely on the judgement of a third-party auditor, since, given that more thorough investigations are more costly, there may be pressure to underestimate the risks of certain feedstocks. Rather, the simple random sampling approach used under the RFS QAP and other EPA fuels programs ensures that there is always a possibility that certain suppliers or aggregators would be verified in a way that is not predictable by the audited parties. We have utilized this approach to great effect in our annual attest engagements and RFS QAP, and believe it is appropriate in this case.

The RFS QAP allows for the use of representative sampling as a way to minimize burden, which would apply to the alternative recordkeeping provisions for separated food waste. Utilizing the representative sampling approach specified at 40 CFR 1090.1805, we would not expect that each feedstock supplier would have to be verified as suggested by the commenters unless a renewable fuel producer utilized a small number of feedstock suppliers. We believe the use of representative sampling based on a simple random sample addresses the commenter's concerns while providing a robust methodology to help detect potential fraud.

Comment:

Many commenters said that mandatory QAP under the proposed alternative compliance option is unworkable because there are a limited number of QAP providers. As a result, they believe this will deny bio-refiners access to used cooking oil feedstock in a timely manner. Some commenters were concerned that the QAP requirement for biointermediates would compete for resources required for separated food waste QAP assessments. One commenter noted that the proposed new conflict of interest provisions for third-party providers will put further restrictions on parties' options for selecting a QAP auditor, and that requiring the producer and feedstock supplier to use the same QAP provider is further limiting. This hinders business flexibility as suppliers will not want to be tied to only customers using the same QAP provider.

One commenter stated that requiring the same QAP provider may restrict the ability of the feedstock supplier to sell to multiple parties and may increase their costs, giving them incentives to sell into different markets.

Response:

As discussed in the NPRM and Preamble Section X.H, we chose QAP providers as the best party to implement the alternative recordkeeping requirement due in part to their similarities with CARB's verification bodies.[190] QAP providers also have the expertise and experience necessary to evaluate feedstock properties, which other parties under the program, such as attest auditors, have less experience in. We also have carefully tailored independence requirements for QAP auditors at 40 CFR 80.1471, which as discussed in Preamble Section X.A, we are further enhancing. These independence requirements help ensure that QAP auditors will objectively verify elements of the QAP and identify issues found during audits to EPA and affected parties. The attest engagement provisions, while having their own independence requirements at 40 CFR 1090.55, are not crafted specifically for this purpose and largely lack the provisions of the QAP program to effectively identify, report, and correct issues found during audits.

We note that commenters fail to demonstrate how having four QAP providers that currently have approved plans is insufficient to meet demand and fail to explain why the market would be unable to respond to increased demand for QAP auditors by having new QAP auditors register. We also believe that if there were an increase in demand for QAP auditors as a result of renewable fuel producers wishing to utilize the alternative recordkeeping requirements, either existing auditors would increase capacity to meet the need or additional QAP auditors would provide services. Several commenters noted that California has dozens of parties that provide verification services under their LCFS program, and many of these providers could qualify as QAP auditors.

Although we believe sufficient QAP capacity already exists or will exist to implement the alternative recordkeeping requirements, we are also making some changes to the proposed requirements to reduce the workload on QAP auditors. As discussed in Preamble Section X.H, we are clarifying that the feedstock aggregators would not need to obtain a separate QAP audit from the renewable fuel or biointermediate producer. In other words, the feedstock aggregator would not have to directly participate in the RFS QAP. Instead, the renewable fuel or biointermediate producer would have to participate in the RFS QAP if they were going to utilize the alternative recordkeeping provisions, and the QAP auditor's QAPs would have to describe how feedstock aggregators' records would be verified under the renewable fuel producer's or biointermediate producer's QAP. We believe this approach will reduce the demand on QAP auditors, helping to address the commenter's concerns.

We received a comment, described later in this subsection, that suggests the feedstock aggregators be the only party subject to QAP. We believe placing QAP on the renewable fuel producer aligns better with the program structure, which places first liability on the renewable fuel producer.

[190] 87 FR 80702.

Also, as discussed in Preamble Section X.A and RTC Section 11.1, we are finalizing modifications to the proposed third-party oversight enhancements that will both make the new independence requirements less burdensome on independent third parties under the RFS program, and provide more time for independent third parties to review and adjust to the new requirements. We believe these changes address commenters' concerns that the third-party oversight enhancements will further constrain the availability of QAP auditors to support the alternative recordkeeping requirements.

We note that because we are not requiring feedstock suppliers or feedstock aggregators to directly participate in the RFS QAP, the commenter's concerns with respect to increased burden associated with requiring the same QAP auditor for both parties are rendered moot.

Comment:

Multiple commenters reference that the feedstock records contain CBI and the feedstock aggregators do not want to provide records to the renewable fuel producers.

One commenter stated that providing documentation to a third party to verify the information needed to establish the renewable biomass requirement can address concerns raised regarding confidential business information.

Response:

As discussed in Preamble Section X.H, we proposed the alternative recordkeeping requirement due to stakeholders' concerns over information asserted as CBI, which renewable fuel producers stated limited their ability to obtain records. As a result, we proposed that rather than renewable fuel producers holding records of the locations from which the feedstocks were collected themselves, independent auditors would be allowed to verify these records directly from the feedstock supplier. The commenters do not explain how the alternative recordkeeping requirements do not protect informed that is claimed as CBI. Feedstock aggregators have the option to utilize the alternative recordkeeping requirements if they are concerned about renewable fuel producers accessing what they claim to be CBI.

Comment:

One commenter requested that EPA explicitly state that it recognizes that customer lists are CBI and that CBI is not required to be shared with processors.

Response:

We have not determined that customers lists are CBI, which is a term of art under EPA's regulations. EPA does not have any stake in any CBI determination for information that we do not receive. However, in response to concerns we have heard from stakeholders we are providing the alternative recordkeeping provision so that feedstock aggregators do not have to share their customer lists with renewable fuel producers so long as all the requirements of 40 CFR 80.1479 are met.

Comment:

Multiple commenters said that the alternative compliance option does not approximate the approach used by the California Air Resources Board. One commenter stated that the CARB LCFS program does not require that the fuel producer possess and maintain point of origin records for feedstocks, and instead requires that the fuel producer ensure access to the necessary records.

One commenter stated that EPA should leverage the producers who are already EPA registered and apply the CARB verification method.

One commenter generally welcomes EPA's proposal to provide a reasonable alternative to the recordkeeping requirements for separated food waste, but objected to the use of QAP. The commenter stated that the LCFS as well as the International Sustainability and Carbon Certification program require auditing of a subset of the feedstock suppliers to ensure compliance with the relevant regulations, and that this should be emulated instead of requiring QAP participation.

Another commenter suggested that EPA mandate that annual attest engagements contain the same chain-of-custody information required by CARB under LCFS and enhance those requirements to include contractual provisions that feedstock suppliers maintain and make available to third-party auditors documenting the establishment locations and volumes obtained.

The commenter suggests aligning with the feedstock verification requirements of the LCFS.

Response:

We recognize that there are some differences between CARB's LCFS auditing of feedstock suppliers and the program we proposed. While we have endeavored to provide a comparable approach to ensuring compliance under the RFS, having full overlap between the programs is not possible given our different statutory authorities and different regulatory histories and frameworks.

As a general matter, we have required renewable fuel producers to keep records demonstrating that their feedstock qualifies as renewable biomass under the program since 2010. Requiring such records is therefore not new with this action. In this action, we are providing parties with an additional flexibility to comply with this long-existing requirement by allowing an option that is similar to LCFS in that feedstock aggregators, as opposed to the renewable fuel producers, can hold the records so long as those records are audited. While what we proposed and are finalizing here is similar to LCFS, details such as who the auditors are, how they conduct audits, and the feedstock categories into which the auditors classify feedstocks necessarily differ between the RFS and LCFS. The RFS approach leverages the preexisting QAP program, which EPA currently uses to verify that RINs are accurate. While it differs from verification under the LCFS program, the QAP provides the level of assurance, through site visits, that is necessary to ensure separated food waste meets the requirements to qualify as a feedstock under the CAA and our RFS regulations. In the absence site visits and the other verification requirements we are finalizing here, we are concerned that non-qualifying feedstocks, such as palm oil, may be utilized.

The feedstock review conducted by QAP auditors in this alternative recordkeeping requirement involves a site visit to verify that the feedstock aggregator has the necessary equipment to gather, preprocess, and transport feedstocks, as applicable. Without a site visit, the potential exists for an entity to import non-qualifying feedstocks and create false records. It is our understanding that LCFS auditing of feedstock aggregators does not include site visits but instead uses on risk based sampling, which relies on the professional judgement of the auditor to conduct sampling. In contrast, QAP providers must either verify all information for all batches a renewable fuel producer has produced or verify a representative sample of batches selected via simple random sampling under 40 CFR 80.1469(c)(5). We believe this approach is more appropriate for the RFS program than risk- or judgment-based auditing because there is less variation in the value of credits for fuels produced from different feedstocks (e.g., used cooking oil and beef tallow receive the same RIN D-codes), the simple random sampling ensures all feedstock aggregators have a chance for being evaluated, and the simple random sampling is less subject to the judgement of the auditor, which we believe can be influenced by the cost of extensive reviews. In other words, simple random sampling provides a deterrent effect by maintaining the possibility that records from any given feedstock supplier could be audited and the verification of records by auditors will be more objective than a targeted or risk-based approach. Given the advantages of the existing QAP approach and concerns with the LCFS approach, we are not adopting the LCFS approach to auditing and verification, nor are we providing a regulatory option to leverage LCFS verification in lieu of the RFS requirements.

Furthermore, with regards to leveraging LCFS, we believe it is inappropriate to leverage CARB's regulatory requirements because California's regulatory requirements only apply to fuels produced and/or used in California. Most renewable fuels are produced and used outside of California and therefore most producers cannot utilize CARB's regulatory regime to demonstrate that feedstocks qualify. There are also substantive differences between the RFS and LCFS (e.g., LCFS does not require all feedstocks to be renewable biomass), that would make directly leveraging the LCFS verification scheme infeasible.

Comment:

Multiple commenters said that the records created under CARB's requirements should be sufficient to show that UCO qualifies under RFS.

Response:

We acknowledge that the regulatory regime of California (LCFS plus other regulatory provisions) could result in the generation of records demonstrating the location and amounts where UCO was generated, and that those records could be consistent with the information required under 40 CFR 80.1454(d) and (j). Specifically, where the programs overlap, records generated by feedstock suppliers and aggregators under Cal. Code Regs. Tit. 3, § 1180.24 - Requirements to Document and Track the Collection, Transport, and Receipt of Inedible Kitchen Grease could meet the regulatory requirements under 80.1454(j) so long as those records include the locations and weights and are kept by the renewable fuel producer under 40 CFR 80.1454(d) and (j) or by the feedstock aggregator as specified in 40 CFR 80.1479. However, our regulatory provisions at 40 CFR 80.1454(d) and (j) also specify who holds those records and who is liable for violations; these requirements are distinct from the requirements under LCFS.

Comment:

Multiple commenters suggested that the supplier be able to hold the records without being subject to the alternative recordkeeping requirements.

One commenter suggested requiring fuel producers to enter into agreements with suppliers requiring them to retain the necessary records for five years and provide the information directly to the fuel producer's RFS auditors and EPA upon request.

Response:

As stated in the NPRM,[191] the recordkeeping requirements exist to ensure that renewable fuels are produced from renewable biomass. To ensure these requirements are effective, renewable fuel producers must be able to determine with confidence that their feedstock qualifies under the RFS program. The regulations at 40 CFR 80.1454(d) state that "any domestic producer of renewable fuel as defined in 40 CFR 80.1401 that generates RINs for such fuel must keep documents associated with feedstock purchases and transfers that identify where the feedstocks were produced and *<u>are sufficient to verify that feedstocks used are renewable biomass</u>*…" (emphasis added). Because of the long history of fraud involving these types of feedstocks described in Preamble Section X.H, we believe that an approach that solely relies on feedstock aggregators to maintain records without guaranteed verification by the renewable fuel producer or an independent third-party auditor would likely result in additional opportunities for noncompliance and fraud under the RFS program. The approach we are finalizing in this action provides the necessary oversight by either having the renewable fuel producer collect records sufficient to verify that feedstocks used are renewable biomass, which include the location and weights as specified under 40 CFR 80.1454(j), or by having the feedstock aggregator keep the records in conjunction with the renewable fuel producer participating in the RFS QAP and the QAP auditor verifying the records that the feedstock aggregator kept.

The commenters do not specify how having the feedstock aggregator hold the records provides the requisite level of confidence to the renewable fuel producer or EPA that any feedstocks used are renewable biomass. In our alternative recordkeeping option, an auditor will verify the records, though the commenters do not suggest any type of verification activity. Given our experience with fraud in this part of the RFS program, we are not incorporating the commenters' suggestions as an option. We proposed the alternative recordkeeping requirement due to requests that the supplier hold the records. The commenters have presented adjustments to the proposed requirements, some of which we have incorporated into this final action. Our program is designed to ensure that renewable fuel is produced from qualifying feedstocks. A renewable fuel producer that does not have access to feedstock records may be inadvertently generating RINs on non-qualifying feedstocks. The commenters do not explain, that without the additional checks in

[191] 87 FR 80700.

the alternative recordkeeping requirements, how to ensure renewable fuel is produced from qualifying feedstocks.

Comment:

One commenter suggested allowing suppliers to provide the information directly to a neutral third party or renewable fuel producer's QAP auditor who would hold the information for the required record retention period and provide the records to EPA upon request.

The commenter suggested "allowing third parties to manage a publicly verifiable, immutable record that can prove the digital originality of any compliance document held by a UCO collector or aggregator so the third-party can minimize the time it must maintain sensitive documents while allowing each UCO collector or aggregator to control the protections is accepts for its sensitive data."

One commenter stated that EPA should clarify in its final rule the circumstances in which third parties can maintain records regarding separated food waste on behalf of a producer under EPA's existing regulations. For example, EPA should clarify that producers can satisfy 40 CFR 80.1454(d) and (j) by contracting with an independent third party that will receive all required records directly from suppliers and maintain them in a format accessible to EPA.

Response:

As discussed in Preamble Section X.H, we have allowed third parties contracted by the renewable fuel producer to hold records of separated food waste sources' location and amount under the existing regulatory requirements at 40 CFR 80.1454(d) and (j), as applicable. We did not modify the regulations in a way that would discontinue the allowance of a third party to be contracted to maintain records for a renewable producer.

However, as also discussed in Preamble Section X.H, a renewable fuel producer's QAP auditor cannot be this third party because this would mean the auditor would no longer be independent under 40 CFR 80.1471(b). The commenter does not explain how having a QAP auditor hold records on behalf of a renewable fuel producer would allow the auditor to maintain their independence as required under EPA's regulations. Given this, the regulatory requirements preclude a renewable fuel producer's QAP auditor from holding records on the producer's behalf. Because maintaining independence is important to ensuring that independent third parties perform services under the RFS in an objective manner, as discussed more fully in the third-party oversight enhancements at Preamble Section X.A, it would be inappropriate to allow for a QAP auditor to serve this role. For this reason, we are not finalizing an option for QAP auditors to maintain records for renewable fuel producers.

Likewise, the feedstock aggregator cannot be this third party because they would not solely be holding the records on behalf of the renewable fuel producer. The feedstock aggregator has a potential conflict of interest in this situation since they may benefit from purchasing cheaper, non-qualifying feedstocks and not disclosing this information to the renewable fuel producer. We proposed and are finalizing alternative requirements in 40 CFR 80.1479 to provide oversight to address the potential conflict of interest in the case where the feedstock aggregator holds the records instead of the renewable fuel producers.

Comment:

Some commenters suggested requiring a system of self-declarations where 1) restaurants/points of origin would sign a self-declaration that their product is made from renewable biomass and submit these self-declarations to the UCO collector ("feedstock supplier") that aggregates the product directly from the restaurants/points of origin; 2) the UCO collector would hold all self-declarations and write its own self-declaration to provide to renewable fuel producer; and 3) during the annual attest, the auditor can speak with the UCO collector to confirm compliance.

Response:

Since it is not possible to verify self-declarations without additional documentation, we are not allowing self-declarations to meet the recordkeeping requirements in 40 CFR 80.1454(d) and (j). Auditing and enforcing based on self-declarations is difficult, especially when the underlying records originate from parties that EPA does not directly regulate or originate outside of the U.S. The commenter fails to describe how self-declarations are sufficient to show the renewable fuel producer, auditors, and EPA that the feedstock qualifies under the program. The commenter does not explain how speaking with a UCO collector is sufficient to verify the feedstock.

Comment:

Multiple commenters suggested allowing used cooking oil (UCO) suppliers to provide documentation to an electronic third-party database that permits EPA or auditors access to the data while denying access to renewable fuel producers. For UCO suppliers who cannot supply the data to the electronic database, suppliers and aggregators would be allowed to keep paper or electronic records and work with renewable fuel producers' auditors to access the records.

One commenter also suggested allowing the use of a technology-based solution where collectors could, upon verifier or EPA request, provide location and volume information for each UCO establishment.

One commenter suggested that a third-party data management company could be the entity that provides such a technical solution to sharing and storing information required when using separated food waste.

One commenter suggested "creating third parties that are independent of the EPA and funded by renewable fuel producers to create, implement, and oversee data governance strategies used by these third-parties to validate that the compliance documents submitted to a third-party by a UCO collector or aggregator indicate adherence to the intent of 80.1454(d) and 80.1454(j) without threatening the confidentiality or commercial value of any data submitted to an individual third-party".

One commenter supports the creation of a technology-based solution, and that there are several that the industry can use to ensure all separated food waste is made with renewable biomass. If this approach is chosen, then EPA needs to be crystal clear on what is needed to meet this requirement.

One commenter supports the creation of a technology-based solution, and that there are several that the industry can use to ensure all separated food waste is made with renewable biomass. If this approach is chosen, then EPA needs to be crystal clear on what is needed to meet this requirement.

Response:

As discussed in Preamble Section X.H, the regulations at 40 CFR 80.1454(d) and (j) allow renewable fuel producers to hire third parties to maintain records on their behalf, and we are not modifying the regulations in a manner that would disallow this practice. We believe this could take the form of a technological platform, similar to what the commenters suggest. This has helped parties manage the confidential business information concerns that the commenters mention under the existing regulatory provisions at 40 CFR 80.1454. The recordkeeping regulations at 40 CFR 80.1454 do not specify the format that renewable fuel producers, or third parties acting on their behalf, must use to meet the applicable recordkeeping requirements. Records may be kept in a variety of formats, including electronically as suggested by the commenter, as long as the renewable fuel producer meets the applicable recordkeeping requirements.

Given that such options already exist for meeting the recordkeeping requirements, we do not believe there is a need for EPA to build and maintain a recordkeeping system. Furthermore, recordkeeping is the responsibility of regulated parties, not EPA, and we believe parties have multiple entities that can help with meeting the recordkeeping requirement without EPA developing a system.

It is the renewable fuel producers' responsibility to ensure the validity of the renewable fuel produced. If EPA asks for the records described in 40 CFR 80.1454(d) or (j) and the records are not available or do not show that the renewable fuel was produced from renewable biomass, then the RINs are invalid and the renewable fuel producer would be responsible for retiring/replacing those RINs.

With regards to technical solutions associated with determining the amount of food waste obtained from a particular location, we want to clarify how parties should handle situations when amounts cannot be accurately measured directly at each location. If this is the case, the amounts collected within a truck can be measured and allocated proportionally to the locations based on the container size for the pickup. For example, a truck exclusively picking up separated food waste from bins in a residential neighborhood may not be able to measure the weight of each household's separated food waste when placing it on the truck. However, they can measure the total weight of the food waste after the truck has completed its route, and they can use the size of the bins as a secondary check to confirm the accuracy of the measurement. In this case, we believe it to be consistent with the regulations for feedstock aggregators to allocate the weight of the truck to each location based on the bin sizes of the locations for which they were contracted and scheduled to pick up food waste and for which they picked up food waste, if not empty. We hope this provides clarity on how to appropriately allocate amounts of food waste.

Comment:

One commenter suggested that EPA allow feedstock suppliers to opt into the QAP program on their own, under the same conditions as in the Set Rule proposal. QAP auditors would need to get their protocols approved by EPA, and then would audit the suppliers to ensure regulatory compliance. The auditor would list the feedstock supplier in its own registration information, as they do today for renewable fuel producers. Producers could rely on their feedstock suppliers' active listing as sufficient demonstration of compliance with 80.1545(d) and (j). The commenter further states that EPA could, under this suggested approach, add a new feedstock code to indicate these verified feedstock streams and a new fuel code for producers using verified feedstocks. This may encourage more participation in QAP because aggregators wouldn't be limited to selling only to renewable fuel producers who also engage in QAP. As such, the commenter also recommends not imposing transfer limits on verified feedstock suppliers.

Response:

We did not propose and are not finalizing a transfer limit as suggested by the commenter. What we are finalizing (i.e., requiring QAP only for the renewable fuel producer, and not for the feedstock aggregator) differs from what the commenter suggested for multiple reasons, described below.

We believe placing QAP on the renewable fuel producer aligns better with the program structure, which places liability on the renewable fuel producer. It is unclear how the RFS program's liability scheme would apply were we to place QAP solely on the feedstock aggregator.

We received multiple comments recommending that feedstock aggregators not be subject to QAP for the alternative recordkeeping requirement, stating that feedstock aggregators would not sign up for the program if they were subject to QAP, reducing available volumes of renewable fuel. Based on consideration of these and other comments, we believe the renewable fuel or biointermediate producers are better equipped to handle the QAP program than feedstock aggregators.

The commenter's recommendation would be a substantial change that would need further fleshing out and would benefit from public input on how it would be best designed and implemented.

Comment:

One commenter stated that there can be 33,000 individual records per 1 million gallons of UCO, and requiring transfer of all of these records to the renewable fuel producer is infeasible.

Response:

The commenter does not clearly describe why transfer of records is infeasible if going to the renewable fuel producer but not if transferred to an attest auditor for auditing. Regardless, the addition of the alternative recordkeeping requirement, which does not involve transfer of records to the renewable fuel producer, would appear to solve the concern of the commenter.

Comment:

One commenter suggested requiring QAP to be annual rather than quarterly.

Response:

Because of the long history of RIN fraud involving feedstocks claimed to be used cooking oil and the relative ease in which non-qualifying oils can be substituted for or blended with UCO, EPA believes that quarterly desk audits are required for the QAP to effectively ensure that records kept by the feedstock aggregator verify that feedstocks claimed as UCO qualify as renewable biomass as specified in 40 CFR 80.1454. These quarterly audits are important to ensure that qualifying feedstock is being used. Feedstock aggregators have the option to give the required records to the renewable fuel producers if they don't want QAP audits quarterly.

Comment:

Commenters stated that EPA should define "feedstock supplier." One commenter stated that the burden of registering, hiring a QAP provider, and record-keeping is cost prohibitive to a small supplier like an individual restaurant. Additionally, if these individual "feedstock suppliers" did comply, the number of registrations and compliance activities would bog down EPA's current system. The commenter also noted that if "feedstock suppliers" mean aggregators, then that term will need to be clearly defined.

Response:

We have added separate definitions for feedstock supplier and feedstock aggregator to differentiate between the two entities. In this action, feedstock suppliers generate the separated food waste feedstocks, such as restaurants. Feedstock aggregators collect feedstocks from feedstock suppliers and distribute it to renewable fuel or biointermediate producers. These definitions should provide clarity to the commenters. By not requiring feedstock suppliers to register, we expect that the number of registrants that could register under the alternative recordkeeping provisions are significantly decreased.

Comment:

Multiple commenters wrote that many feedstock suppliers are small entities without the resources to understand and manage participation in the RFS program. The likelihood that they would fail to meet the requirements is significant and their concern about penalties would result in them not supplying feedstock for renewable fuel production.

Response:

It is unclear whether the commenter is discussing the feedstock supplier or the feedstock aggregators. We believe that by removing the requirement for QAP for the feedstock aggregators, as discussed above, and by not requiring the feedstock suppliers to register, we have addressed the commenter's concern.

If feedstock aggregators are unable to keep records for the location and amount of separated food waste pickups, they are not able to adequately verify that their feedstock is renewable biomass and should not be supplying feedstock for use in RFS.

Comment:

The commenter stated that both the current and proposed regulations are so arduous that if adopted could shut down the ability to legally use UCO as a feedstock in the US.

One commenter was concerned that the regulatory requirements, as proposed, may continue to restrict the potential supply of these feedstocks.

Response:

The commenter suggested that the current and proposed regulations would result in UCO not being used as an RFS feedstock. The recordkeeping requirements at 80.1454(d) have been in place since 2010, the recordkeeping requirements in 80.1454(j) have been in place since 2020, and RINs have continued to be generated for fuels that use UCO as a feedstock. It is therefore not clear on what basis the commenter is making its claim. We note that our alternative recordkeeping requirements add a significant flexibility and will allow for feedstock aggregators to maintain records instead of renewable fuel producers as long as all applicable requirements are met. We have also finalized modifications to the proposal that we believe will reduce the burden associated with utilization of the alternative recordkeeping requirements. These modifications include clearly specifying that it is feedstock aggregators and not feedstock suppliers that must keep the records and clarifying that feedstock aggregators do not have to directly participate in the RFS QAP.

If feedstock aggregators are unable to keep records for the location and amount of separated food waste pickups, they are not able to adequately verify that their feedstock is renewable biomass and should not be supplying feedstock for use in the RFS program.

Comment:

One commenter recommends that EPA make it clear that only the type of food waste and the type of facilities from which it comes need to be reported and not specific locations or individual records.

Response:

The information tracking feedstocks to their generation location (e.g., a particular restaurant) and providing the amounts of feedstocks is necessary to ensure that feedstocks qualify as renewable biomass. Generalized information of the nature the commenter suggests is not sufficient to verify that any particular quantity of feedstock that is used to produce RIN-generating renewable fuel is actually renewable biomass. As stated in Preamble Section X.H, our regulations require renewable fuel producers to keep records associated with feedstock purchases and transfers that identify where the feedstocks were produced and are sufficient to verify that feedstocks used are renewable biomass, or follow the alternative recordkeeping requirements in in § 80.1479. This includes the specific locations where the feedstock is produced.

Comment:

The commenter recommends that 40 CFR 80.1479(e) be modified to clarify that locations are required to be kept in records but not identified during registration or reporting.

Response:

The proposed 40 CFR 80.1479(e) is titled "Recordkeeping." The commenter does not explain why more clarity is needed. We did not propose nor are we finalizing that feedstock aggregators provide locations during registration or submit periodic reports. We believe the proposed regulatory requirements at proposed 40 CRR 80.1479(e) clearly indicate that this is a recordkeeping requirement and that further language could be confusing to some stakeholders.

Comment:

One commenter stated that the proposed regulatory text at 40 CFR 80.1479(e) requires anaerobic digesters to maintain records of the location of establishments from which food waste is sourced by cross-referencing 40 CFR 80.1454. The commenter suggests that EPA amend provision at 40 CFR 1479(e) to read as follows: "(e) Recordkeeping. The feedstock supplier must keep all applicable records for the collection of separated yard waste, separated food waste, separated MSW, and biogenic waste oils/fats/greases as specified in 40 CFR 80.1450(b)(1)."

Response:

The requirements in 40 CFR 80.1450 are for registration, not recordkeeping. The two sets of requirements (registration and recordkeeping) entail the provision of different information, at different points in the fuel production process, for different purposes. The commenter does not explain why 40 CFR 80.1479(e) should not reference 40 CFR 80.1454, given that 80.1454 contains the recordkeeping provisions. We believe it is clearer to reference recordkeeping provisions when discussing recordkeeping requirements. In addition, referencing the registration requirements would not require keeping the location and amounts of separated food waste feedstock, such that the records would not be sufficient to show the renewable fuel is produced from renewable biomass. While we are not changing the reference to the registration provisions, we are clarifying that 40 CFR 80.1479(e) references 80.1454(j), and we believe this will provide more clarity to stakeholders.

We also note that biogas producers that use separated food waste as a feedstock in an anaerobic digester to produce biogas must also meet the applicable regulatory requirements (including the recordkeeping requirements) for the use of such feedstock.

Comment:

One commenter recommended that EPA publish the regulations for an alternative compliance approach as a standalone section or subsection of the Code of Federal Regulations instead of cross-referencing its preexisting biointermediate provisions. Cross-referencing adds an additional layer of complexity and incorporates additional compliance requirements that EPA may not have intended.

Response:

We are already including the provisions for the alternative recordkeeping requirements in a separate regulatory section (40 CFR 80.1479). We believe cross-referencing leverages the regulations already developed, makes understanding the similarities and differences between the two approaches easier, and allows for more consistency between QAP and the alternative compliance approach. The commenter did not specify which cross-references incorporate additional compliance requirements, so it is not clear what benefit would be obtained from writing a standalone section or subsection.

Comment:

One commenter suggested that EPA could require that producers use carbon-14 testing to demonstrate the biogenic content of the separated food waste used as feedstock in order to have it classified as renewable biomass under the program.

Response:

While carbon-14 testing may be able to show whether a feedstock is biogenic, such testing would not be able to show that the feedstock is qualifying used cooking oil, for example, rather than non-qualifying oils because many non-qualifying oils (like palm oil) are also biogenic. Relying on the use of C-14 testing for the purpose of demonstrating that a feedstock is qualifying separated food waste would make it more likely that non-qualifying oils are presented as compliant and result in the generation of invalid or fraudulent RINs. For these reasons, we did not propose and are not finalizing the use of C-14 testing as an approach to demonstrate that feedstocks qualify as renewable biomass as suggested by the commenter.

Comment:

One commenter noted that "[w]hile some food waste is seen as a valuable commodity and aggregator business records, such as invoices, indicate volumes and locations of collection, other wastes are collected for free. Accurately tying volumes to locations or business records is difficult and reduces the amount of available waste feedstocks for biomass-based diesel that meets the agencies current compliance obligations."

One commenter argued that EPA failed to adequately explain why the recordkeeping requirements at 40 CFR 80.1454(j)(1)(ii) are necessary.

Response:

CAA section 211(o)(1)(J) requires that renewable fuels be produced from renewable biomass, and to ensure compliance with this requirement, EPA's RFS regulations since the original 2010 RFS2 final rule have required that records showing that the feedstock is renewable biomass be kept. This includes the locations and amounts collected from feedstock suppliers. If records are not available for these feedstocks, then it cannot be shown to be renewable biomass, should not be used under the program, any RINs generated for such fuels may be invalid, and the party should not be receiving any revenue from the RIN. Given this, it is important that volumes should be accurately tied to locations in order to ensure renewable fuel is produced from renewable biomass.

Comment:

One commenter suggested EPA should use prior 2015 guidance on Separated Food Waste, which continues to be accessible on EPA's website at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/presentation-separated-food-waste-plans-renewable, as the basis of a practical solution to this question. This guidance requires a producer's Separated Food Waste Plans to identify either point sources or aggregators. It then allows aggregators and producers to list regions of collection for the separated food waste collected. This regional approach would adequately shield the confidential business information of suppliers from producers while still meeting the requirement to know source locations. Additionally, producers would continue to be responsible for compliance under the RFS and could transact business, including setting in place contractual requirements, knowing that failure to comply with the RFS' regulatory requirements may result in invalidating RINs or other penalties. Lastly, third party providers under QAP could validate that business records align with feedstock volumes purchased, but the QAP providers would not be required to trace every feedstock to its exact source location in order to complete their QAP assessment.

Response:

The 2015 guidance, a presentation titled "RFS Registration for Renewable Fuel Producers," cited by the commenter references registration requirements related to separated food waste plans. It did not apply to recordkeeping requirements. The separated food waste plan provided at registration must only be specific enough for EPA to determine that it is possible for the producer to obtain and use feedstocks that qualify as renewable biomass, while the recordkeeping requirements are intended to ensure that actual quantities of feedstock used to produce renewable fuel were in fact renewable biomass. In fact, the cited guidance does not use the word "record" in the entire document nor are there any references to the RFS recordkeeping requirements at 40 CFR 80.1454. The commenter did not specify how providing information about feedstock collection at the regional scale is specific enough to verify that the feedstock is renewable biomass consistent with the requirements of the statute and the regulatory requirements at 40 CFR 80.1454(d).

Comment:

One commenter suggested that EPA recognize that a third-party auditor is able to maintain the necessary source information and volumes collected from each supplier and that the fuel producer would then be in compliance with the current Separated Food Waste Plan and Feedstock requirements. The necessary information housed by the third-party auditor would be accessible to the fuel producer's attestor and would be available to EPA upon request. This would greatly simplify the process and provide the necessary assurance that the Separated Food Waste feedstocks are complaint.

Response:

To the extent the commenter is confusing the registration and recordkeeping requirements, we note that a separated food waste plan is a requirement at registration and is not relevant for verifying that the feedstocks actually used to produce renewable fuel were renewable biomass. Furthermore, third-party auditors have independence requirements that prevent them from holding records on behalf of the biointermediate or renewable fuel producer. Because the independent third-party would be directly liable for the renewable fuel producer's compliance with the recordkeeping requirements, holding records for the renewable fuel producer would constitute an interest or appearance of interest in the renewable fuel producer's operations.[192] The commenter's approach does not consider the independence requirements for third-party auditors, and we believe that allowing QAP or attest auditors to maintain records for renewable fuel producers would significantly undermine those auditors' ability to perform their services objectively. Given the importance of independence requirements for third-party auditors, we are not allowing third-party auditors to hold records on behalf of their clients.

Comment:

One commenter noted that the ability to "opt-in" to the RFS program adversely impacts the waste market and small businesses. It requires registration, submission to EPA's jurisdiction, use of the same QAP provider as the renewable fuel producer customer, payment of QAP expenses, and assumption of the same liability as producers. 87 FR at 80755. The commenter believes participation in the QAP program, specifically, will deter many feedstock suppliers from participating. Some suppliers with advanced technical solutions may opt-in, while others may be unwilling to provide their data to producers or participate in the QAP program. Thus, EPA effectively embargoes large quantities of low-carbon feedstocks from the renewable fuel market. Moreover, the proposal adversely impacts many small businesses by having them choose between providing their confidential business information (e.g., customer lists) to producers or participate in yet another regulatory program. According to EPA's proposal, a UCO supplier

[192] The regulations at 40 CFR 80.1471(b) prohibit such conflicts of interest for QAP auditors and at 40 CFR 1090.55 for attest auditors.

unwilling to turn over confidential business information to a competitor could be required to hire the same QAP provider as all renewable fuel producers to whom they supply separated food wastes. The additional costs required to employ personnel to manage participation in the RFS program and pay for QAP provider services are likely to result in higher feedstock prices that ultimately get passed on to the consumer and increased operational costs, if the burdens and costs do not drive the suppliers from the market altogether.

One commenter also said that larger aggregators may be disinclined to implement a QAP program.

Response:

We have modified our proposal to only require the renewable fuel or biointermediate producer to register with QAP, if they opt-into the alternative recordkeeping requirement. We believe this addresses the commenters' concerns around the burden of feedstock suppliers participating.

We also note that waste market participants (e.g., feedstock aggregators and renewable fuel producers) do not have to participate in the RFS program. The RFS offers these parties an additional source of revenue for their wastes and products if they can demonstrate that they qualify under the program. Given that participation in RFS for these parties is optional, we disagree with the commenter that the program burdens these parties.

Comment:

One commenter stated that if EPA requires suppliers to maintain establishment location and volume records under its alternative compliance option, EPA must conduct initial and final regulatory flexibility analysis to estimate the new requirement's financial impact on small businesses and minimize the impact. Given the expense and time required to comply with EPA's recordkeeping requirements and the availability of the CARB approach that allows a producer to retain a third-party verifier to audit feedstock records, EPA should revise the alternative compliance.

Response:

The recordkeeping requirements at 40 CFR 80.1454(d), which require renewable fuel producers to keep documents associated with feedstock purchases and transfers that identify where the feedstocks were produced and are sufficient to verify that feedstocks used are renewable biomass, have been in place since 2010, the recordkeeping requirements in 40 CFR 80.1454(j) have been in place since 2020, and RINs have continued to be generated for fuels that use UCO as a feedstock.

For feedstock aggregators and renewable fuel and biointermediate producers, participation in RFS is voluntary, and hinges on the renewable fuel or biointermediate producer showing that the renewable fuel is produced consistent with the statutory and regulatory requirements. If the cost of showing that renewable fuel is produced from renewable biomass is too expensive for these parties, they are not required to participate in the program.

The alternative recordkeeping requirement we are finalizing will not increase the burden on stakeholders relative to the existing requirements because it is an optional, alternative option. If a company decides that for them it is more cost effective to comply with 40 CFR 80.1454(j), the company can use those provisions, and not need to be subject to 40 CFR 80.1479. The commenter's analysis fails to include this flexibility.

In this action, we are finalizing an alternative to the existing regulatory requirements at 40 CFR 80.1454(d) and (j) that collectively require renewable fuel producers to obtain records for separated food waste concerning the location of feedstock suppliers and amount of feedstock collected at each location in order to demonstrate that renewable fuel was produced from renewable biomass consistent with the Clean Air Act and EPA regulatory requirements. Under this action, renewable fuel producers that choose to use the alternative in 40 CFR 80.1479 will not have to obtain those records from feedstock suppliers and instead may rely upon feedstock aggregators maintaining those records if several conditions are met. This approach will provide additional flexibility for all renewable fuel producers, including those that are small businesses, in complying with the RFS recordkeeping requirements. We note that only parties that find the additional flexibility economically viable would be anticipated to participate. Other parties can instead comply with the current RFS recordkeeping requirements.

As discussed earlier in this subsection, the CARB approach cited by the commenter is not a widely available or applicable approach. In addition to differences between the needs of our program and theirs, California regulatory requirements do not apply to renewable fuel producers that operate outside of California. Additionally, we do not believe the CARB verification scheme is sufficient for purposes of the RFS to ensure the validity of feedstocks used to produce renewable fuel and we are choosing instead to leverage a different program that already exists under the RFS: the QAP program.

Moreover, EPA has fulfilled its Regulatory Flexibility Act (RFA) obligations with regard to this rulemaking as explained in the preamble and RIA Chapter 11. Specifically, EPA certified that this final rule does not "have a significant economic impact on a substantial number of small entities." Therefore, EPA is not required to conduct either an initial or final regulatory flexibility analysis.

Comment:

One commenter stated that EPA should simplify and streamline the proposal related to separated food waste recordkeeping to further enable compliance and reduce the administrative burden, while assuring protections against fraud.

Response:

The commenter did not offer any specific suggestions or criticisms for us to consider. We note that as discussed in Preamble Section X.H, we have finalized modifications to the proposal to clarify, simplify, and streamline provisions that will reduce administrative burden associated with the alternative recordkeeping requirements.

Comment:

One commenter stated that EPA must include provisions to compel the feedstock suppliers to provide the information needed, but not in a way to undermine the potential supply for biodiesel producers. For example, one potential option may be to require the producer to obtain a third-party verification of the supplier's information akin to attest engagements to confirm the volume of supply provided. The producer and feedstock supplier could contract how the costs could be shared, and, to the extent the producer is already utilizing a QAP, the QAP provider could serve as that auditor.

Response:

The alternative recordkeeping provisions require the producer to utilize a QAP provider to verify the records held by the feedstock aggregator. The commenter appears to request the alternative recordkeeping requirement that we proposed. We are finalizing this option, which we believe addresses the commenter's concerns.

Comment:

One commenter stated that the proposed alternative option is impractical in its application as it requires renewable fuel producers and separated food waste suppliers to register with the QAP program. This would (1) require new parties (separated food waste suppliers) to register with EPA, (2) limit such suppliers to supplying only a single biofuel facility per year, and (3) require burdensome quarterly audits.

Response:

We disagree with the commenter's assertation that the proposed alternative recordkeeping requirements are impractical. Regardless, we have made modifications to the proposal that we believe will reduce the administrative burden associated with the alternative recordkeeping requirements. As noted in Preamble Section X.H, we are revising the proposed requirement to provide that feedstock aggregators do not have to directly participate in the QAP program. We also did not propose nor are we finalizing, as suggested by the commenter, that feedstock aggregators be limited to supplying feedstock to a single renewable fuel production facility.

As discussed above, we believe that quarterly audits under the RFS QAP are necessary to ensure that feedstocks are produced from renewable biomass under the alternative recordkeeping requirements finalized in this action. We note that we allow representative sampling under the RFS QAP to limit the scope of RFS QAP audits and we believe that this is an effective way to limit the administrative burden of participation in the RFS QAP while at the same time providing a robust mechanism to verify that feedstocks qualify as renewable biomass.

11.8 Definition of Ocean-Going Vessels

Comment:

One commenter believes that the proposed definition is too narrow, is inconsistent with the Clean Air Act, and does not accurately reflect the type of vessels that engage in ocean-going transit.

The commenter said that the proposed definition states that "ocean-going vessels" are those "vessels that are primarily (*i.e.*, ≥75 percent) propelled by engines meeting the definition of 'Category 3' in 40 CFR 1042.901," and that EPA explains in the preamble that fuel used in Category 1 and Category 2 auxiliary engines on such vessels does not need to be included in the obligated party's renewable volume obligation (RVO) calculations. The commenter states that it is unclear from this proposed definition how an obligated party suppling marine fuel would have knowledge about the percentage of propulsion provided by a vessel's various Category 1, 2, or 3 engines.

The commenter highlighted that the Clean Air Act excludes "fuel used in ocean-going vessels" from the definition of "transportation fuel," but the statute does not define an "ocean-going vessel" or "fuel used in ocean-going vessels." Moreover, stated the commenter, the Clean Air Act does not limit the scope of "fuel used in ocean-going vessels" to only vessels with Category 3 engines. The commenter recommended that EPA look to the actual use of a vessel and determine if it engages in ocean transportation of goods. The commenter described tug barges ("ATBs") with Category 1 and Category 2 engines as an example, stating that ATBs: (1) travel in international waters and perform the same function as large vessels with Category 3 engines; and (2) move cargo on the ocean between U.S. ports. The commenter argues that there is no justification under the Clean Air Act and the RFS program to exclude such vessels from the definition of "ocean-going vessels." The commenter stated that the definition should be based on a vessel's operation and capability, not the category of engine employed.

The commenter suggested that U.S-flag and foreign vessels should be able to meet a definition of "ocean-going vessels" based on length of the vessel, tonnage, certification/classification by the U.S. Coast Guard, or records to demonstrate they are "ocean-going." The commenter argued that such a definition would align the RFS program with similar fuel programs, including California's Low Carbon Fuel Standard, 17 Cal. Code Regs. § 95481(109). Therefore, the commenter recommends, EPA should adopt a broader definition of "ocean-going vessels" that is consistent with the intent of the Clean Air Act and reflects actual operation of the vessels to which marine fuel suppliers sell their product.

Response:

As explained in the NPRM, auxiliary engines equipped on large ocean-going vessels are typically used for purposes other than propulsion (e.g., electricity generation). Auxiliary engines, however, can be used for propulsion in emergencies, which is why the proposed definition was based on the engine type primarily used for propulsion. However, if a vessel is equipped with a Category 3 engine it can be assumed that the vessel will primarily use that engine for propulsion because it would not be practical or economical to propel that vessel primarily with smaller engines. Therefore, we are finalizing a modified definition of ocean-going vessel that is consistent with the intent of the proposed definition, which turns exclusively on whether the vessel is equipped with a Category 3 engine. Specifically, we are defining "ocean-going vessels" as "vessels that are equipped with engines meeting the definition of "Category 3" in 40 CFR 1042.901."

The commenter's suggestion that ocean-going vessel status be based on "records to demonstrate they are ocean-going" would inject even more uncertainty as to which vessels are ocean-going vessels under the RFS program and would be nearly impossible to implement and enforce. To determine whether a volume of fuel should have been included in RVO calculations, the obligated party and EPA would need to identify what routes the vessel operates, when the vessel operated in international waters versus domestic waters, and whether the routes the vessel operates changed during the time period in question. Basing the ocean-going vessel determination solely on the category of the engine equipped on the vessel is a bright line rule that obligated parties and EPA can use to determine which volumes of fuel must be included in RVO calculations.

The commenter's suggestion that ocean-going vessel status be based on length or tonnage are potentially more discernable criteria, but would require the regulated community to conduct more diligence to determine whether a vessel qualifies as ocean going because information regarding vessel length and tonnage may not be as readily available, may cause confusion, and would be inconsistent with how EPA has regulated engines equipped on ocean-going vessels in other contexts. See, e.g., 40 CFR 1042.650, 1040.650(d) (exempting auxiliary engines installed on vessels with Category 3 propulsion engines from the requirements of 40 CFR part 1042 if certain criteria are met). It is unclear how U.S. Coast Guard certification/classification would be easier to discern than the presence of a Category 3 marine engine, and basing ocean-going vessel status on "records to demonstrate that they are 'ocean-going'" would require the regulated community to make its own determination as to whether the records are sufficient to demonstrate ocean-going status. Ultimately, the presence of a Category 3 engine is the simplest way to determine whether a vessel is ocean-going.

Further, the definition of "ocean-going vessel" is not only important in determining which volumes of fuel are included in RVO calculations, but it is also used in determining whether a renewable fuel producer can generate RINs. If a refiner blends biodiesel into ultra-low sulfur diesel (ULSD) that is sent to a marine terminal, it can assume that the fuel is used in Category 1 and 2 non-ocean-going vessels because a vast majority of ULSD supplied to marine terminals is used by those types of vessels and generate RINs on the volume of biodiesel sent to the marine terminal, unless it knows or has reason to know that the fuel was used for a non-transportation purpose (e.g., if the ULSD is used as a cutter stock to blend down the sulfur content of marine gas oil on an ocean-going vessel). If vessels could also qualify as "ocean-going vessels" based on their length, tonnage, U.S. Coast Guard certification/classification, or "records to demonstrate that they are 'ocean-going'" these renewable fuel producers either would not generate RINs on the biodiesel, or they would be required to identify the vessels receiving the ULSD, find out the vessel's length or tonnage, find out the vessel's U.S. Coast Guard certification or classification, and locate and examine the vessels' records to determine whether the biodiesel would be used for transportation purposes and, accordingly, would be eligible for RIN generation.

11.9 Bond Requirement for Foreign RIN-Generating Renewable Fuel Producers

Comment:

Multiple commenters opposed increasing the bond amount from 1-cent per RIN to 30-cents per RIN, stating that a 30x increase is unnecessary for deterrence and that existing provisions provide adequate deterrence. One commenter stated that EPA did not explain the basis for 30-cents per RIN number and suggested that 3-cents per RIN would be more appropriate.

Response:

We disagree that 1-cent or 3-cents are reasonable amounts to use for calculating the bond given current RIN prices. When we first established the bond amount in the RFS1 rule in 2007, we believed that 1-cent would comprise a significant enough portion of the RIN price to effectively deter noncompliance. However, RIN prices have risen by two orders of magnitude since 2010 and 1-cent now represents only approximately 0.3% of the D3 RIN price at the time of proposal (or approximately 0.4% of the average D3 RIN price over 2018-2022). This is inadequate to serve the bonding requirement's enforcement purpose. Therefore, we proposed to use 10% of the then current value of a D3 RIN ($3.00) to come up with a bond amount of 30-cents. We believe that a bond value of 10% of D3 RIN price is a reasonable amount that both makes the bond amount effective and workable, and ensures that the bonding requirement is feasible for foreign renewable fuel producers. In consideration of the comments received, we have instead looked at the average D3 RIN price for the most recent, full five-year period, 2018-2022 ($2.23) and are amending the amount to 10% of that average price, or 22-cents.

Comment:

One commenter stated that EPA has provided no examples of noncompliance or nonpayment to support the foreign bonding requirement. The comment believes that enforcement mechanisms applicable to both domestic and foreign entities are sufficient.

Response:

We did not newly introduce the foreign bonding provisions in the Set rule proposal; this requirement has been in existence since the inception of the RFS1 program. In establishing these provisions, EPA considered the difficulty of enforcing against entities without significant presence in the United States. We believe the existence of the foreign bonding provisions remain necessary to help ensure that foreign RIN generators and foreign RIN owners generate and transact RINs in a manner consistent with Clean Air Act and EPA regulatory requirements. We proposed only to adjust the amount used to calculate the bond (see response to previous comment) and to remove a payment by check option that has proven difficult for EPA to implement (see response to subsequent comment).

Comment:

A commenter opposed removal of the option to write a check to the US Treasury instead of a bond for foreign producers, citing other instances where payments are submitted to the US Treasury.

Response:

Receiving payment by check written to the US Treasury in the amount of a bond has proven very difficult for EPA to implement. In settling upon the method of payment, EPA considered a variety of situations in which bonds and other financial assurances are used, including the financial assurance methods under Resource Conservation and Recovery Act (RCRA), the Alcohol and Tobacco Trade Board (TTB) brewer's bonds, including surety and collateral ("cash") bonds, and bonding under OTAQ's Transition Program for Equipment Manufacturers (TPEM) program. After considering a variety of potential payment methods, we believe the only method that is appropriate for foreign producers under the RFS is bonding and we are finalizing the regulation as proposed. The difficulty with accepting cash payments is too great, despite EPA's efforts to successfully implement this option, because the EPA has not been able to identify a mechanism for EPA to receive payments via the US Treasury efficiently and safely. Also, we note that foreign producers do not need to provide a bond at all if they do not wish to generate RINs. A foreign producer may elect to have the importer generate the RINs instead and thereby avoid having to meet the bonding requirement altogether.

Comment:

One commenter supported the proposal to increase the bond amount to 30-cents and supported EPA's proposal to remove the payment by check option. They note that the biodiesel industry had previously requested that EPA increase its oversight over biodiesel via vessels, including increasing the bond amount.

Response:

We thank the commenter for their support.

12. Other Comments

12.1 Point of Obligation and Impact on U.S. Refining Assets

Comment:

We received comments suggesting that EPA should change the point of obligation to blenders, which would better align the obligation to the parties who perform the blending (in contrast to refiners who sometimes do not blend fuel). The commenters claimed this would increase blending in the future and move in the direction of a nationwide low-carbon fuel standard, similar to California.

Response:

The D.C. Circuit in *Alon Refining Krotz Springs v. EPA*, 936 F.3d 628 (D.C. Cir. 2019) held that EPA "has no duty to reconsider the appropriateness of its point of obligation regulation as part of its yearly determination of volumetric requirements." *Id.* at 659. EPA acknowledges that it has discretion to reevaluate the point of obligation in the set rule should it choose to do so. EPA did not solicit comment on or otherwise reexamine this issue in this rulemaking. We decline to reopen this issue.

We believe that our examination of this issue in the Point of Obligation Denial document remains valid.[193] In that proceeding, we provided the public with notice and an opportunity to comment on a proposed denial. We received over 18,000 comments, and carefully evaluated all comments. In an 85-page final decision, we decided to maintain the existing point of obligation (i.e., refiners and importers of gasoline and diesel).[194] We supported our decision with a comprehensive analysis of the impacts on fuel refiners, blenders, and retailers, as well as of a vast array of other economic and regulatory factors.

Additionally, we recently revisited our analysis regarding RIN cost passthrough in denying small refinery exemptions, finding that small refineries do not experience disproportionate economic hardship from the RFS program.[195] In reaching this decision, we analyzed more recent data since the Point of Obligation Denial, addressed numerous comments, and confirmed that all obligated parties—including small refineries—recover their compliance costs through the market price they receive when they sell their fuel products and thus do not bear a hardship created by compliance with the RFS program. This finding also supports our decision to maintain the current point of obligation.

We acknowledge that we have again received comments asking us to reevaluate or revise the point of obligation from some parties. However, we are not aware of new information or analyses that warrant our reconsidering this issue at this time. We received many substantively similar comments on our small refinery action and have addressed those comments in that

[193] See "Denial of Petitions for Rulemaking to Change the RFS Point of Obligation," November 22, 2017.
[194] 40 CFR 80.1406(a).
[195] See "June 2022 Denial of Petitions for RFS Small Refinery Exemptions," EPA-420-R-22-011, June 2022.

proceeding.[196] We also address comments regarding the economic impacts of this rulemaking in RTC Section 9 and RIA Chapter 10. Specifically, we address the RIN cost impacts on refiners in RTC Section 9.1.9.

[196] See "June 2022 Denial of Petitions for RFS Small Refinery Exemptions: Appendices," EPA-420-R-22-011A, Appendix B, June 2022.

12.2 Environmental Justice

Comment:

Several commenters stated that the combustion of biofuels (biodiesel and ethanol) in vehicles and engines produces fewer criteria pollutants than traditional diesel or gasoline, which can benefit populations near trucking corridors and other roadways. These commenters also point to mitigation of GHGs as a benefit to EJ communities.

Response:

As discussed in RIA Chapter 4 and 9, combustion of renewable fuels may increase some pollutants and decrease others. Given the magnitude of the volume changes in this rule, the emission and air quality impacts are expected to be relatively small. In any event, even considering the full projected increase in ethanol and biodiesel use, the air quality impacts are expected to be small.

Emission impacts from the production of fuels, however, can have more significant localized impacts. In RIA Chapter 9 we indicate that while emissions increases associated with biofuel production may adversely affect near-facility populations, reductions in petroleum sector emissions may benefit their nearby populations.

As we explain in RIA Chapter 9, GHG reductions are a benefit to EJ communities.

Comment:

Numerous commenters were opposed to the inclusion of biogas from animal manure and landfills in the RFS program, whether that is used to generate RINs via CNG/LNG or electricity. Many of these commenters stated that EPA does not have sufficient information on a majority of concentrated animal feeding operations (CAFOs) to estimate their environmental impacts. Many commenters also believed that the RFS program and programs like it drive consolidation and expansion of large animal farms. These commenters also suggested that EPA include solar, wind, nuclear, geothermal, hydro, and other forms of renewable energy in the RFS program.

Response:

CNG/LNG generated from biogas is already eligible to generate RINs under the RFS program. Commenters provided little substantive evidence to support their belief that the RFS program is driving consolidation or expansion of large animal feeding operations, or that the proposed volumes were likely to do so. While it is clear that larger facilities are of the size and scale required to economically support processing biogas into RNG and establishing a pipeline interconnect, this does not mean that the RFS program is a driver of the expansion of large scale animal agriculture that has taken place in the U.S. There are a host of other factors much more likely to dictate facility sizing. To the extent that the comments relate to eRINs, we are not taking any final action on eRINs in this rulemaking. All other forms of electricity are not eligible to generate RINs under the RFS program. Broader environmental comments expressed with respect to landfills and CAFOs are beyond of scope of this action. The assessment of the 20 factors, including various environmental factors, is a requirement of the statute in establishing the renewable fuel volumes; however, CAA section 211(o) does not provide EPA with any additional authority by which we can regulate water, air, or other environmental impacts of such facilities.

Comment:

Several commenters stated that food and fuel price impacts are borne disproportionately by lower income households.

Response:

EPA acknowledges this and discusses food price and fuel price impacts on low-income consumer units in RIA Chapter 9. The lowest and second-lowest quintile of consumer units in the US will experience disproportionate impacts on their food expenditures compared to the average consumer unit.

12.3 Timing and Comment Period

Comment:

Several commenters suggested that EPA should expeditiously finalize the rule. They pointed to the importance of certainty in the market to renewable fuel producers.

Response:

We have taken steps to promptly finalize this action. We recognize the importance of timeliness and regulatory certainty to the smooth implementation of the RFS program and to our stakeholders, including biofuel producers and obligated parties.

Comment:

Several stakeholders submitted comments and requests that EPA should extend the comment period. Commenters suggested that the comment period was too short and did not provide stakeholders an opportunity to meaningfully comment on the action.

Response:

EPA denied three such requests in February 2023, and those letters are provided in the docket for this action. In short, we disagree with commenters that there was not an opportunity to meaningfully comment. Our action is in compliance with CAA section 307(d), which requires only that EPA keep the record for comment open for 30 days after the opportunity for the oral presentation of data, views, or arguments. The comment period closed 30 days after our public hearing and was also open prior to the public hearing.

12.4 Beyond the Scope

Comment:

Commenters addressed numerous additional topics, including but not limited to the following:

- EPA's denial of small refinery exemption petitions.
- Additional changes to the existing RFS regulations, including tying RIN generation to carbon intensity, implementing RIN trading reforms (e.g., RIN price cap), modifications to the biointermediate provisions, changing the definition of renewable biomass, and excluding transmix from a refiner's RVO.
- Allowing renewable fuel producers to generate RINs on renewable fuel used in U.S.-flagged ocean-going vessels.
- Suggestions for new RIN-generating pathways (e.g., hydrogen, sustainable aviation fuel).
- Changes to the E15 misfueling mitigation plans.
- Regulatory action to extend the 1-psi waiver to E15.
- Introduction of new mid- and higher-level ethanol blends into the market (e.g., E30).
- Updates to EPA's existing lifecycle analyses.

Response:

These comments are all beyond the scope of this rulemaking. While we did propose several changes to the RFS program as part of this action, we did not propose any of the changes described above or otherwise seek comment on these issues. Many of these issues, moreover, are being addressed in separate proceedings. These topics are not further addressed in this document.