**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Parts 80 and 1090**

**[EPA–HQ–OAR–2021–0427; FRL–8514–02–OAR]**

**RIN 2060–AV14**

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

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** Under the Clean Air Act, the Environmental Protection Agency (EPA) is required to determine the applicable volume requirements for the Renewable Fuel Standard (RFS) for years after those specified in the statute. This action establishes the applicable volumes and percentage standards for 2023 through 2025 for cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel. This action also establishes the second supplemental standard addressing the judicial remand of the 2016 standard-setting rulemaking. Finally, this action makes several regulatory changes to the RFS program, including changes related to the treatment of biogas and other modifications to improve the program's implementation. At this time EPA is not finalizing proposed provisions related to the generation of RINs from qualifying renewable electricity.

**DATES:** This rule is effective on September 11, 2023, except for amendatory instruction 30, which is effective on February 1, 2024, and amendatory instructions 41 and 42, which are effective on April 1, 2024. The incorporation by reference of certain publications listed in this regulation is approved by the Director of the Federal Register as of July 12, 2023. The incorporation by reference of ASTM D1250, ASTM D4442, ASTM D4444, ASTM D6866, and ASTM E870 was approved by the Director of the Federal Register as of July 1, 2022. The incorporation by reference of ASTM D4057, ASTM D4177, ASTM D5842, and ASTM D5854 was approved by the Director of the Federal Register as of April 28, 2014. The incorporation by reference of ASTM E711 was approved by the Director of the Federal Register as of July 1, 2010.

**ADDRESSES:** EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2021–0427. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material is not available on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

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

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

| Category | NAICS [a] codes | Examples of potentially affected entities |
|---|---|---|
| Industry | 112111 | Cattle farming or ranching. |
| Industry | 112210 | Swine, hog, and pig farming. |
| Industry | 221210 | Manufactured gas production and distribution, and distribution of renewable natural gas (RNG). |
| Industry | 324110 | Petroleum refineries. |
| Industry | 325120 | Biogases, industrial (*i.e.,* compressed, liquefied, solid), manufacturing. |
| Industry | 325193 | Ethyl alcohol manufacturing. |
| Industry | 325199 | Other basic organic chemical manufacturing. |
| Industry | 424690 | Chemical and allied products merchant wholesalers. |
| Industry | 424710 | Petroleum bulk stations and terminals. |
| Industry | 424720 | Petroleum and petroleum products merchant wholesalers. |
| Industry | 454319 | Other fuel dealers. |
| Industry | 562212 | Landfills. |

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

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

## Table of Contents

A red-line version of the regulatory language that incorporates the changes in this action is available in the docket for this action.

## I. Executive Summary

The Renewable Fuel Standard (RFS) program began in 2006 pursuant to the requirements of the Energy Policy Act of 2005 (EPAct), which were codified in Clean Air Act (CAA) section 211(o). The statutory requirements were subsequently amended by the Energy Independence and Security Act of 2007 (EISA). The statute sets forth annual, nationally applicable volume targets for each of the four categories of renewable fuel for the years shown below.

TABLE I–1—YEARS FOR WHICH THE STATUTE PROVIDES VOLUME TARGETS

| Category | Years |
|---|---|
| Cellulosic biofuel | 2010–2022 |
| Biomass-based diesel | 2009–2012 |
| Advanced biofuel | 2009–2022 |
| Renewable fuel | 2006–2022 |

For calendar years after those for which the statute provides volume targets, the statute directs EPA to determine the applicable volume targets in coordination with the Secretary of Energy and the Secretary of Agriculture, based on a review of the implementation of the program for prior years and an analysis of specified factors:

- The impact of the production and use of renewable fuels on the environment, including on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply; [1]
- The impact of renewable fuels on the energy security of the U.S.; [2]
- The expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and biomass-based diesel); [3]
- The impact of renewable fuels on the infrastructure of the U.S., including deliverability of materials, goods, and products other than renewable fuel, and the sufficiency of infrastructure to deliver and use renewable fuel; [4]
- The impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods; [5] and
- The impact of the use of renewable fuels on other factors, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices.[6]

While this statutory requirement does not apply to cellulosic biofuel, advanced biofuel, and total renewable fuel until compliance year 2023, it applied to biomass-based diesel (BBD) beginning in compliance year 2013. Thus, EPA established applicable volume requirements for BBD volumes for 2013–2022 in prior rulemakings.[7] This action establishes the volume targets and applicable percentage standards for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel for 2023–2025. We are also promulgating a number of regulatory changes intended to improve the operation of the RFS program. This action describes our rationale for the final volume targets and regulatory changes. Responses to comments received from stakeholders on the proposed rule can be found in the associated Response to Comments (RTC) document.

Low-carbon fuels are an important part of reducing greenhouse gas (GHG) emissions in the transportation sector, and the RFS program is a key federal policy that supports the development, production, and use of low-carbon, domestically produced renewable fuels. This "Set rule" marks a new phase for the program, one which takes place following the period for which the Clean Air Act enumerates specific volume targets. We recognize the important role that the RFS program can play in providing ongoing support for increasing production and use of renewable fuels, particularly advanced and cellulosic biofuels. For a number of years, RFS stakeholders have provided input on what policy direction this action should take, and the Agency greatly appreciates the sustained and constructive input we have received from stakeholders. We appreciate the many comments we received, not only on the volumes that we proposed on December 30, 2022, but also on the

[1] CAA section 211(o)(2)(B)(ii)(I).
[2] CAA section 211(o)(2)(B)(ii)(II).
[3] CAA section 211(o)(2)(B)(ii)(III).
[4] CAA section 211(o)(2)(B)(ii)(IV).
[5] CAA section 211(o)(2)(B)(ii)(V).
[6] CAA section 211(o)(2)(B)(ii)(VI).
[7] See, *e.g.*, 87 FR 39600 (July 1, 2022), establishing the 2022 BBD volume requirement.

analyses we conducted and the proposed regulatory changes. EPA looks forward to continued engagement with stakeholders on the RFS program.

### *A. Summary of the Key Provisions of This Regulatory Action*

#### 1. Volume Requirements for 2023–2025

Based on our analysis of the factors required in the statute, and in coordination with the Departments of Agriculture and Energy, we are establishing the volume targets for three years, 2023 to 2025, as shown below. We proposed setting standards for three years to strike an appropriate balance between improving the program by providing increased certainty over a multiple number of years and recognizing the inherent uncertainty in longer-term projections. After reviewing stakeholder comments and considering the statutory deadlines for establishing RFS volume obligations we have determined that this three-year timeframe remains appropriate. In addition to the volume targets for 2023–2025, we are also completing our response to the D.C. Circuit Court of Appeals' remand of the 2016 RFS annual rule in *Americans for Clean Energy* v. *EPA,* 864 F.3d 691 (2017) (''*ACE*'') by establishing a supplemental volume requirement of 250 million gallons of renewable fuel for 2023. This ''supplemental standard'' follows the implementation of a 250-million-gallon supplement for 2022 in a previous action.[8]

TABLE I.A.1–1—FINAL VOLUME TARGETS

[Billion RINs] [a]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel | 0.84 | 1.09 | 1.38 |
| Biomass-based diesel [b] | 2.82 | 3.04 | 3.35 |
| Advanced biofuel | 5.94 | 6.54 | 7.33 |
| Renewable fuel | 20.94 | 21.54 | 22.33 |
| Supplemental standard | 0.25 | n/a | n/a |

[a] One RIN is equivalent to one ethanol-equivalent gallon of renewable fuel. Throughout this preamble, RINs are generally used to describe total volumes in each of the four categories shown above, while gallons are generally used to describe volumes for individual types of biofuel such as ethanol, biodiesel, renewable diesel, etc. Exceptions include BBD (which is always given in physical volumes) and biogas (which are always given in RINs).

[b] The BBD volumes are in physical gallons (rather than RINs).

As discussed above, the statute requires that we analyze a specified set of factors in making our determination of the appropriate volume requirements. Many of those factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract. As a result, we needed to identify a set of renewable fuel volumes to analyze prior to determining the volume requirements that would be appropriate to establish under the statute. To this end, we began by using a subset of the statutory factors that are most closely related to production and consumption of renewable fuel, and other relevant factors, to identify ''candidate volumes.'' We then analyzed the impacts of the candidate volumes on the other economic and environmental factors that the statute lists. The derivation of these candidate volumes is discussed in Section III. Section IV discusses the analysis of those candidate volumes for the other economic and environmental factors. Finally, Section VI discusses our conclusions regarding the appropriate volume requirements to establish in light of all of the analyses that we conducted and all of the comments we received from stakeholders at the public hearing on January 10 and 11, 2023, written comments, letters, and other meetings and input provided to us.

The cellulosic biofuel volumes we are finalizing in this rule for 2024 and 2025 are lower than the proposed volumes as they do not include cellulosic biofuel from eRINs (all eRIN volumes projected in the proposal have been zeroed out in this final rule). The decreases in the cellulosic biofuel volumes for 2024 and 2025 are partially offset by increases in the projected volumes of non-eRIN cellulosic biofuel (*i.e.,* CNG/LNG derived from biogas and ethanol from corn kernel fiber) for all three years. The advanced and total biofuel volumes reflect both these changes in cellulosic biofuel, and our new, higher projections of the availability of BBD relative to the proposed rule. The final volumes also reflect our decision to maintain a 15.0 billion gallon implied conventional biofuel requirement for all three years (plus an additional 250 million gallon supplemental volume requirement for 2023 to complete EPA's response to the *ACE* remand), consistent with the statutory level from 2015 through 2022, rather than increasing this volume to 15.25 billion gallons in 2024 and 2025 as we originally proposed.

The volume targets that we are establishing in this action have similar status as those in the statute for the years shown in Table I–1. Specifically, they are the basis for the calculation of percentage standards applicable to producers and importers of gasoline and diesel unless they are waived in a future action using one or more of the available waiver authorities in CAA section 211(o)(7).

#### 2. Applicable Percentage Standards for 2023–2025

For years after 2022,[9] the CAA gives EPA authority to establish percentage standards for several years simultaneously and at the same time that it establishes the volume targets for those years. Consistent with the proposed rule, we are finalizing the percentage standards for 2023, 2024, and 2025. The percentage standards corresponding to the volume requirements from Table I.A.1–1 are shown below.

[8] See 87 FR 39600, 39628–29 (July 1, 2022) (discussing approaches for responding to the *ACE* remand).

[9] Although the statute requires EPA to establish applicable percentage standards annually by November 30 of the previous year, as discussed in Section II, this requirement does not apply to years after 2022. CAA section 211(o)(3).

TABLE I.A.2–1—PERCENTAGE STANDARDS

| | 2023 (%) | 2024 (%) | 2025 (%) |
|---|---|---|---|
| Cellulosic biofuel | 0.48 | 0.63 | 0.81 |
| Biomass-based diesel | 2.58 | 2.82 | 3.15 |
| Advanced biofuel | 3.39 | 3.79 | 4.31 |
| Renewable fuel | 11.96 | 12.50 | 13.13 |
| Supplemental standard | 0.14 | n/a | n/a |

The formulas used to calculate the percentage standards in 40 CFR 80.1405(c) require that EPA specify the projected volume of exempt gasoline and diesel associated with exemptions for small refineries granted because of disproportionate economic hardship resulting from compliance with their obligations under the program under CAA section 211(o)(9). For this rulemaking, we have projected that there are not likely to be small refinery exemptions (SREs) for 2023–2025 based on the information available at the present time. This issue is discussed further in Section VII along with the total nationwide projected gasoline and diesel consumption volumes used in the calculation of the percentage standards.

As in previous annual standard-setting rulemakings, the applicable percentage standards for 2023–2025 are added to the regulations at 40 CFR 80.1405(a).

3. Carryover RINs and Gasoline and Diesel Projections

EPA assesses the availability of carryover RINs in determining the volumes under our set authority. Carryover RINs provide important benefits to the RFS program, including compliance flexibility to individual obligated parties, liquidity to the RIN market, and mitigation against market impacts that could occur if RIN generation in any year exceeds or falls short of the required volume of renewable fuel.

In establishing RFS volume requirements for 2020 and 2021 that were equal to the number of RINs generated in those years, EPA intended that compliance with the renewable volume obligations would not impact the total number of available carryover RINs. Since that time, obligated parties have submitted compliance reports for the 2020 and 2021 compliance years. These reports revealed that there exist significant differences between the volume of obligated fuel reported by obligated parties, on the one hand, and the volumes of gasoline and diesel from EIA that EPA used to calculate the percentage standards for 2020 and 2021 on the other. Higher-than-expected volumes of obligated fuel in 2020 and 2021 meant that the number of RINs that must be retired for these compliance years was higher than EPA anticipated. As discussed in greater detail in Section III.C.4 and RIA Chapter 1.10, compliance with these obligations has required the use of significant quantities of carryover RINs, resulting in effectively no available carryover RINs for several renewable fuel categories going into the 2022 compliance year. In an effort to better project the volume of obligated fuel in future years, we are adjusting how we project the obligated volume of gasoline and diesel in 2023–2025. These changes are discussed further in Section VII.A and RIA Chapter 1.11.

4. Regulatory Provisions for eRINs

The 2023–2025 proposed rule included a comprehensive program governing the generation of RINs from renewable electricity produced from biogas that is used in electric vehicles. The proposed ‘‘eRIN’’ regulations laid out a comprehensive approach to eRIN generation and program implementation, and included details on multiple design elements, including the entities that would be eligible to generate eRINs, approaches to ensure the prevention of double-counting of such RINs, and data requirements for valid eRIN generation. In addition to the proposed eRIN program, the December 2022 proposal also described several alternative approaches to how such a program could be established and implemented.

In response to the proposal, we received a wide variety of comments on all aspects of the proposed eRIN program. Stakeholder positions on the proposed eRIN provisions varied greatly, with some stakeholders strongly supportive of EPA finalizing the proposed provisions, some who sought significant modifications to the program while remaining broadly supportive of eRINs conceptually, and others who opposed, for a variety of reasons, EPA moving forward to finalize a new eRIN framework. In light of the significant number of comments provided by stakeholders on EPA’s proposed eRIN approach, and the complexity of many of the topics raised in those comments, and the consent decree deadline on other portions of the rule, we are not finalizing the proposed revisions to the eRIN program at this time. We have adjusted the final volume requirements for this rulemaking to reflect this decision.

The large number of comments EPA received on our proposed eRIN language, representing a range of perspectives, is a clear signal that stakeholders care a great deal about a potential eRIN program. As discussed in the proposed rule, EPA’s policy goal in developing an eRIN program would be to support one of the objectives of the RFS program, which is to increase the use of renewable transportation fuels, in particular cellulosic biofuels, over time, consistent with the statute’s focus on growth in this category. Moreover, an eRIN program would support Congress’ goals of reducing GHGs and increasing energy security,[10] both of which can be affected by the design of that program. We anticipate that an eRIN program may also have the ancillary effect of incentivizing increased electrification of the vehicle fleet.

Given strong stakeholder interest in the proposed eRIN program and the range of potential benefits that the program could provide, EPA will continue to work on potential paths forward for the eRIN program. To that end, EPA will continue to assess the comments received on the proposal. EPA will also seek additional input from stakeholders to inform potential next steps.

[10] Congress stated that the purposes of EISA, in which the RFS2 program was enacted, included ‘‘[t]o move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers, to increase the efficiency of products, building, and vehicles, to promote research on and deploy greenhouse gas capture and storage options, and to improve the energy performance of the Federal Government, and for other purposes.’’ Public Law 110–140 (2007). See also, CAA 211(o)(1) (definitions of qualifying biofuel include requirement that they reduce greenhouse gas emissions by specified amounts relative to a petroleum baseline).

5. Other Regulatory Changes

We also proposed regulatory changes in several areas to strengthen EPA's implementation of the RFS program. Stakeholders provided valuable comment on these proposed modifications, and EPA is finalizing many of the proposed changes with modifications based on that stakeholder input. The regulatory changes we are finalizing in this rulemaking include:

- Modification of the regulatory provisions for biogas-derived renewable fuels to ensure that biogas is produced from renewable biomass and used as a transportation fuel and to allow for the use of biogas as a biointermediate.
- Enhancements to the third-party oversight provisions including engineering reviews, the RFS quality assurance program, and annual attest engagements.
- Establishing a deadline for third-party engineering reviews for three-year registration updates.
- Updating procedures for the apportionment of RINs when feedstocks qualifying for multiple D-codes (*e.g.,* D3 and D5) are converted to biogas simultaneously in an anaerobic digester.
- Revising the conversion factor in the formula for calculating the percentage standard for BBD to reflect increasing production volumes of renewable diesel.
- Flexibility for RIN generation.
- Reiterating the prohibition on generating RINs for fuels not used in the covered location.
- Flexibilities for the generation and maintenance of records for waste feedstocks.
- Clarifying the definition of fuel used in ocean-going vessels.
- Modifications to the bonding requirements for foreign parties that participate in the RFS program.
- Other minor changes and technical corrections.

Each of these regulatory changes is discussed in greater detail in Section X.

We proposed but are not finalizing at this time the following regulatory changes:

- A definition of produced from renewable biomass (discussed more in Section X.K).
- The proposed changes to the requirements for the separation of RINs.[11]

We need more time to consider the public comments received on these proposed changes.

[11] See 87 FR 80707 (December 30, 2022).

*B. Environmental Justice*

In considering environmental justice in this action, we have sought to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on communities with environmental justice concerns in the United States.

This rule is projected to reduce GHG emissions, which would benefit communities with environmental justice concerns who are disproportionately impacted by climate change due to a greater reliance on climate sensitive resources such as localized food and water supplies which may be adversely impacted by climate change, as well as having less access to information resources that would enable them to adjust to such impacts.[12 13] The manner in which the market responds to the provisions in this rule could also have non-GHG impacts. For instance, replacing petroleum fuels with renewable fuels will also have potential impacts on water and air exposure for communities living near biofuel and petroleum facilities given the potential for biofuel facilities to have increased emissions of certain criteria pollutants in local communities, resulting in a potential corresponding decrease in exposure for local communities surrounding petroleum facilities with less petroleum production. Replacing petroleum fuels with renewable fuels is also projected to increase food and fuel prices, the effects of which will be disproportionately borne by the lowest income individuals. We received extensive comment, primarily on the proposed eRIN provisions, from community-based and environmental justice stakeholders expressing concern over the use of biogas, particularly from landfills and concentrated animal feeding operations, in the RFS. While EPA is not finalizing eRIN provisions as part of this rule, we will continue to engage with stakeholders on impacts of the RFS program related to biogas use and expansion. Our assessment of potential economic impacts on communities with environmental justice concerns is provided in Section IV.E.3.

[12] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[13] USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *http://dx.doi.org/10.7930/J0R49NQX.*

*C. Impacts of This Rule*

CAA section 211(o)(2)(B)(ii) requires EPA to assess a number of factors when determining volume targets for calendar years after those shown in Table I–1. These factors are described in the introduction to this Executive Summary, and each factor is discussed in detail in the Regulatory Impact Analysis (RIA) accompanying this rule. Congress provided 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. For two of these statutory factors—costs and energy security—we provide monetized impacts for the purpose of comparing costs and benefits. For the other statutory factors, we are either unable to quantify impacts, or we provide quantitative estimated impacts that nevertheless cannot be easily monetized. Thus, we are unable to quantitatively compare all of the evaluated impacts of this rulemaking. Regardless of whether we monetized a factor or not, however, EPA did consider all statutory factors in this rulemaking, and we find that the final volumes are appropriate under the set authority when we balance all the relevant factors. Table ES–1 in the RIA provides a list of all of the impacts that we assessed, both quantitative and qualitative. Our assessments of each factor, including the impacts on costs, energy security, climate, and other environmental and economic factors, are summarized in Section IV of this document. Additional detail for each of the assessed factors is provided in RIA Chapters 4 through 10.

Monetized impacts on cost and energy security are summarized in Table I.C–1 below using two discount rates (3 percent and 7 percent) following federal guidance on regulatory impact analyses.[14] Summarized impacts are calculated in comparison to a No RFS baseline as discussed in Section III.D and are summed across all three years of standards.

[14] Office of Management and Budget (OMB) *Circular A–4.* Sept. 17, 2003.

TABLE I.C–1—CUMULATIVE MONETIZED FUEL COSTS AND ENERGY SECURITY BENEFITS OF 2023–2025 STANDARDS WITH RESPECT TO THE NO RFS BASELINE

[2022$, millions]

| | Discount rate | |
|---|---|---|
| | 3% | 7% |
| *Excluding Supplemental Standard:* | | |
| Fuel Costs | $23,218 | $22,366 |
| Energy Security Benefits | 524 | 505 |
| *Including 2023 Supplemental Standard:* | | |
| Fuel Costs | 23,846 | 22,994 |
| Energy Security Benefits | 536 | 517 |

*D. Policy Considerations*

This rule comes at a time when substantial policy developments and global events are affecting the transportation energy and environmental landscape in unprecedented ways. The Inflation Reduction Act (IRA) makes historic investments in a range of areas, including in clean vehicle and alternative fuel technologies, that will help decarbonize the transportation sector and bolster a variety of clean technologies. Provisions in the IRA will accelerate many of the pollution-reducing shifts that are already occurring as part of a broad energy transition in the transportation, power generation, and industrial sectors. Major new incentives in legislation for cleaner vehicles, carbon capture and sequestration, biofuels infrastructure, clean hydrogen production, and other areas have effectively shifted the policy ground—and it is on this new ground that EPA must develop forward-looking policies and implement existing regulatory programs, including the RFS program.

Even as the IRA bolsters future investments in clean transportation technologies, EPA recognizes that maintaining and strengthening energy security in the near term remains an important policy consideration. The war in Ukraine has significantly destabilized multiple global commodity markets, including petroleum markets, and continues to have impacts in these areas. In addition, global reductions in refining capacity, which accelerated during the pandemic, have further tightened the market for transportation fuels like gasoline and diesel. Programs like the RFS program help boost energy security by supporting domestic production of fuels and diversifying the fuel supply, and it has played an important role in incentivizing the production of low-carbon alternatives. At the same time, EPA recognizes that the transition to such alternatives will take time, and that during this transition maintaining stable fuel supplies and refining assets will continue to be important to achieving our nation's energy and economic goals as well as providing consistent investments in a skilled and growing workforce.

It is against this backdrop that EPA is establishing RFS volume requirements for the next three years in this action. The volumes that EPA is finalizing continue to support ongoing growth in renewable fuels, recognizing their benefits, and based on EPA's consideration of the multiple factors identified in the statute. Beyond providing continued support for fuels like ethanol and biodiesel, this action provides a strong market signal for the continued growth of low carbon advanced biofuels, including ''drop-in'' renewable diesel, and cellulosic biofuels. Renewable fuels are a key policy tool identified by Congress for decarbonizing the transportation sector, and this rulemaking sets the stage for further growth and development of low-carbon biofuels in the coming years.

In the proposed rule EPA requested comment on multiple volume scenarios, including limiting the implied volume of conventional renewable fuel to 15.0 billion gallons in 2024 and 2025, and establishing RFS volumes with an implied volume of conventional renewable fuel at or below the E10 blendwall. The volumes we are finalizing in this rule reflect the scenario on which we requested comment wherein we are limiting the implied volume of conventional renewable fuel to 15.0 billion gallons in 2024 and 2025. We have also included an analysis of the projected impact of the other alternative scenarios in RIA Chapter 10.6.

In the proposal EPA also sought public comment on not only the elements of the proposed rule, but also asked for responses to questions on various topics that intersect with the larger energy transition and energy security issues discussed above. For example, several commenters provided responses on the topic of whether and how EPA should consider incorporating some measure of carbon intensity into the RFS program. Many of the commenters who weighed in on this topic pointed to various non-federal ''clean fuel programs'' that are being implemented in different states and jurisdictions and urged EPA to consider changes that would make the RFS program more closely resemble those programs. Other commenters suggested that the RFS program does not lend itself well to such changes and that an entirely new framework would be preferable if EPA were to pursue such carbon intensity-related changes. Many different stakeholders provided suggestions and perspectives on lifecycle analysis tools and approaches, and these comments helped inform the discussion and analysis in this rulemaking package related to the assessment of environmental impacts of renewable fuels.

Multiple commenters also provided input on what RFS-related policies EPA could pursue to incorporate new pathways and technologies into the program. For example, some commenters urged EPA to take steps to integrate carbon capture and storage (CCS) opportunities related to the production of biofuels into the RFS program, while other commenters cited various reasons why EPA should refrain from taking such steps. Similarly, EPA received comment from different stakeholders that took various positions on whether and how hydrogen should be integrated into the RFS program. Many stakeholders also shared their perspectives on how the RFS program can and should be used to further support the development of sustainable aviation fuels (SAF).

EPA appreciates commenters' input on these other policy topics raised in the proposal. We will continue to engage stakeholders on the topics we raised in the December 2022 proposal and welcome continued input on RFS policy options and opportunities. These comments will be used to inform future rulemaking decisions.

EPA also recognizes the concerns that diverse stakeholders have shared about the potential impacts from implementation of the RFS program. Stakeholders have also shared concerns about RIN market dynamics, including RIN price volatility. EPA understands that maintaining and strengthening energy security in the near term remains a policy imperative. The war in Ukraine continues to affect multiple global commodity markets and reductions in global refining capacity, which accelerated during the pandemic, have further tightened the market for transportation fuels like gasoline and diesel. Programs like the RFS program help boost energy security by supporting domestic production of fuels and diversifying the fuel supply, and the RFS has played an important role in incentivizing the production of low-carbon alternatives. At the same time, EPA recognizes that maintaining stable fuel supplies and refining assets continues to be important to achieving our nation's energy and economic goals and retaining a skilled and necessary workforce.

Given these factors, and because we are starting a new phase of the RFS program where Congress has not prescribed volumes and with prospective standards covering three years, careful administration of the RFS program and monitoring of its impacts is critical. EPA intends to use all available data and tools to monitor the implementation of the RFS program and its impacts. EPA is committed to successful implementation of the program, and the Clean Air Act provides EPA the tools to adjust course if appropriate. EPA will monitor a set of indicators that will help us assess the impact from implementation of the final Set rule volumes to determine whether EPA should consider adjusting those volumes or taking other action. These indicators could include, but are not limited to, the following:

- The prices of biofuels relative to the petroleum-based fuels they displace;
- The cost to consumers of transportation fuel;
- The prices of biofuel feedstocks and their impacts on food prices to consumers;
- Changes in domestic energy supply that affect domestic energy security;
- Changes in domestic energy demand that negatively impact the energy security of a State, region, or the U.S.;
- The stability of fuel supplies and domestic refining assets;
- The potential for RIN deficits and noncompliance by obligated parties;
- Signs of market manipulation in RIN markets;
- RIN prices, generally, as an indicator of how the RFS program is functioning, including significant increases in RIN prices;
- Various other impacts of the RFS standards, as appropriate.

In addition to these indicators, EPA will also monitor the volatility in D6 (''conventional'') RIN prices. Specifically, as part of our oversight of program implementation, EPA intends to consider whether the following volatility measure is met:

- A 50% deviation in the monthly average D6 RIN price, relative to the 6-month rolling average D6 RIN price, evaluated at the end of the calendar month and based on EPA data or third-party data, as EPA determines appropriate. EPA would also consider whether changes in RFS standards, other related EPA actions, or court decisions have occurred which affect the relevance of this measure at a particular time.

Based on EPA's assessment of these indicators, the Administrator may then consider using the statutory authorities available under the Clean Air Act to adjust the volume standards or make other programmatic changes. For example, EPA has authority to reconsider its volumes and standards, and has shown its willingness to do so when extreme and unforeseen events require it, such as revising the 2020 and 2021 volumes to account for changes due to the COVID–19 pandemic. For years after 2022, CAA section 211(o)(2)(B)(ii) establishes the processes, criteria, and standards for setting the applicable annual renewable fuel volumes. That provision provides that the Administrator shall, in coordination with the Secretary of Energy and the Secretary of Agriculture and after public notice and opportunity for comment, determine the applicable volumes of each biofuel category specified based on a review of implementation of the program during the calendar years specified in the tables in CAA section 211(o)(2)(B)(i) and an analysis of the multiple factors, as described in Section II.B of this action.[15] Those factors include, for example, the impact of the use of renewable fuels on the cost to consumers of transportation, and the impact of the use of renewable fuel on other factors, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices. As EPA has stated in previous actions, we generally do not think it is appropriate to reconsider and revise previously finalized RFS standards. Revising standards has the potential to decrease market certainty and create unnecessary market disruption (which could in turn exacerbate some of the indicators listed above). At the same time, given the new phase of the program, we want to reiterate our commitment to monitoring various measures to ensure successful program implementation and consider adjusting course if appropriate.

Apart from EPA's authority to reconsider our RFS standards, CAA section 211(o)(7)(A) provides the Administrator the discretion to waive the national quantity of renewable fuel required under the RFS program, upon petition by one or more States, or by any party subject to the requirements of the RFS program. The Administrator may also waive the volume requirements on his own motion. The Administrator may do so only after consultation with the Secretary of Agriculture and the Secretary of Energy and after public notice and opportunity for comment.[16] A waiver may be issued if the Administrator determines that implementation of the RFS volume requirements would severely harm the economy or environment of a State, region, or the United States, or that there is an inadequate domestic supply. EPA has previously interpreted this waiver authority in prior responses to requests for a waiver of the RFS volume requirements[17] and in annual rulemakings.[18] EPA will monitor as appropriate the criteria we have laid out previously in order to determine whether we should adjust volume requirements using existing waiver authority under the statute. These criteria, for example, include whether, under the severe economic harm waiver authority, the harm is occurring with a high degree of certainty, the harm is severe, and whether the harm is to an entire state, region, or the United States.

In addition to monitoring the program's implementation for the

[15] EPA may consider using an expedited process if EPA determines such process is appropriate and consistent with statutory authority.

[16] EPA may consider using an expedited process if EPA determines such process is appropriate and consistent with the statutory waiver authority.

[17] See 73 FR 47168 (August 13, 2008) and 77 FR 70752 (November 27, 2012).

[18] See, *e.g.*, Renewable Fuel Standard Program—Standards for 2020 and Biomass-Based Diesel Volume for 2021 and Other Changes: Response to Comments, EPA–420–R–19–018; see also *American Fuel & Petrochemical Manufacturers* v. *EPA*, 937 F.3d 559, 580 (D.C. Cir. 2019) (upholding EPA's interpretation of the severe economic harm waiver authority in the 2018 RFS rulemaking).

potential need to adjust the standards, EPA will also strengthen existing efforts, and work to develop new tools, to help us monitor and oversee the RIN market. EPA welcomes ideas from stakeholders impacted by the RFS program on how to improve market oversight capabilities, including ideas on how EPA's compliance regulations could be enhanced.

EPA closely monitors the RIN market, and we take seriously claims of RIN market manipulation. In March 2016, EPA entered into a Memorandum of Understanding (MOU) with the Commodity Futures Trading Commission (CFTC).[19] This MOU allows EPA to share RIN transaction data with CFTC to advise EPA on the techniques used to minimize market manipulation, to increase CFTC's understanding of the RIN market, and to conduct oversight for this market. Under the MOU, EPA has met with CFTC to discuss RIN market data and to evaluate strategies to identify and reduce the potential for manipulation in the RFS program.

In June 2019, EPA modified certain elements of the RFS compliance system, in order to improve functioning of the RIN market and prevent any potential manipulation in the RFS compliance market.[20] The 2019 rulemaking requires reporting of RIN holdings above a threshold to help ensure no single party can manipulate the price of RINs through the sheer size of their holdings.[21] Underpinning that reform was the observation that increased transparency would help deter market participants from amassing an excess of separated RINs, which due to the concentration in ownership could result in undue influence or market power. Since EPA implemented these provisions, no company has had RIN holdings which have exceeded the thresholds set in the rule.

The 2019 rulemaking also required reporting of RIN transaction prices to EPA.[22] EPA has utilized the new reported price data to supplement third-party RIN price assessment data. EPA has also increased transparency by aggregating the reporting price data and making it publicly available on our website.[23] We believe that publishing as much data and information on the RIN market as possible, while still protecting confidential business information, improves market transparency and helps obligated parties and other market participants make informed decisions. Since the June 2019 rule, we have not seen data-based evidence of RIN market manipulation. The potential for such behavior, however, remains a concern.

We have recently further expanded our oversight and enforcement capabilities by entering into an MOU with California Air Resources Board (CARB).[24] This MOU expands our oversight capabilities and supports our enforcement activities by leveraging information collected under California's Low Carbon Fuel Standard to help identify non-compliance and potential market manipulation in the renewable fuels and RIN markets. EPA and CARB compliance staff meet regularly to analyze market forces and participant behavior to ensure that our program meets the CAA requirements.

As we begin to implement the Set Rule volumes, EPA will work with partners in federal and state governments to assess what new improvements and modifications could reasonably be made that would further strengthen market oversight and program implementation. Furthermore, within 45 days of publication of the final 2023–2025 rule, EPA will meet with CFTC to review our MOU with CFTC and the sufficiency of the existing RIN data collection to address potential market manipulation. EPA will also discuss with CFTC whether the existing MOU should be revised to allow for the monitoring of daily trades and whether the existing MOU should be revised to include additional market oversight experts, such as the Federal Trade Commission.

### *E. Endangered Species Act*

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. 1536(a)(2), requires that federal agencies such as EPA, in consultation with the U.S. Fish and Wildlife Service (USFWS) and/or the National Marine Fisheries Service (NMFS) (collectively ''the Services''), ensure that any action authorized, funded, or carried out by the action agency is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of designated critical habitat for such species. Under ESA implementing regulations, the action agency is required to formally consult with the Services for actions that ''may affect'' listed species or designated critical habitat, unless the Services concur in writing that the action is not likely to adversely affect ESA-listed species or critical habitat. 50 CFR 402.14. Consultation is not required where the action has no effect on such species or habitat. For several prior RFS annual standard-setting rules, EPA did not consult with the Services under ESA section 7(a)(2).

Consistent with ESA section 7(a)(2) and relevant ESA implementing regulations at 50 CFR part 402, for approximately two years, EPA engaged in technical assistance and informal consultation discussions with the Services regarding this rule. On January 30, 2023, EPA submitted its initial biological evaluation to the Services, and following continued informal consultation—including regular meetings and telephone and email communications between EPA and the Services—on May 20, 2023, EPA submitted to the Services its May 19, 2023 biological evaluation. On May 31, 2023, EPA provided an addendum to the May 19, 2023 biological evaluation in response to a request from NMFS.[25] EPA has determined that this action is not likely to adversely affect listed species and critical habitat. The Services have confirmed that EPA's biological evaluation with the May 31, 2023 addendum is sufficient and USFWS and NMFS 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.

## II. Statutory Requirements and Conditions

### *A. Requirement to Set Volumes for Years After 2022*

The CAA provides EPA with the authority to establish the applicable renewable fuel volume targets for calendar years after those specified in

[19] See ''Memorandum of Understanding Between the Environmental Protection Agency and the Commodity Futures Trading Commission on the Sharing of Information Available to EPA Related to the Functioning of Renewable Fuel and Related Markets'' (2016), available at *https://www.epa.gov/sites/production/files/2016-03/documents/epa-cftc-mou-2016-03-16.pdf.*

[20] See 84 FR 27013–27019.

[21] See 40 CFR 80.1435.

[22] See 40 CFR 80.1451(c)(2).

[23] See ''RIN Trades and Price Information,'' available at *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.*

[24] See ''Confidentiality Agreement Between the United States Environmental Protection Agency Offices of Transportation and Air Quality and Civil Enforcement and the California Air Resources Board for the Sharing of Information.'' August 17, 2021 (on file with EPA).

[25] ''Biological Evaluation of the Renewable Fuel Standard (RFS) Set Rule,'' May 19, 2023, and email from T. Phillips, EPA, to D. Baldwin, NOAA (May 31, 2023) are both available in the docket for this action.

the Act in Section 211(o)(2).[26] For total renewable fuel, cellulosic biofuel, and total advanced biofuel, the CAA provides volume targets through 2022, after which EPA must establish or ''set'' the volume targets via rulemaking. For BBD, the CAA only provides volume targets through 2012; EPA has been setting the biomass-based diesel volume requirements in annual rulemakings since 2013.

This section discusses EPA's statutory authority and additional factors we have considered due to the lateness of this rulemaking, as well as the severability of the various portions of this rule.

*B. Factors That Must Be Analyzed*

CAA section 211(o)(2)(B)(ii) establishes the processes, criteria, and standards for setting the applicable annual renewable fuel volumes. That provision provides that the Administrator shall, in coordination with the Secretary of Energy and the Secretary of Agriculture,[27] determine the applicable volumes of each biofuel category specified based on a review of implementation of the program during the calendar years specified in the tables in CAA section 211(o)(2)(B)(i) and an analysis of the following factors:

• The impact of the production and use of renewable fuels on the environment;[28]

• The impact of renewable fuels on the energy security of the U.S.;[29]

• The expected annual rate of future commercial production of renewable fuels;[30]

• The impact of renewable fuels on the infrastructure of the U.S.;[31]

• The impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods;[32] and

• The impact of the use of renewable fuel on other factors, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices.[33]

Congress provided 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. Additionally, we are not aware of anything in the legislative history of EISA that is authoritative on these issues. Thus, as the Clean Air Act ''does not state what weight should be accorded to the relevant factors,'' it ''give[s] EPA considerable discretion to weigh and balance the various factors required by statute.''[34] These factors were analyzed in the context of the 2020–2022 standard-setting rule that modified volumes under CAA section 211(o)(7)(F),[35] which requires EPA to comply with the processes, criteria, and standards in CAA section 211(o)(2)(B)(ii). Consistent with our past practice in evaluating the factors,[36] we have again determined that a holistic balancing of the factors is appropriate.[37]

In addition to those factors listed in the statute, the statute also directs EPA to consider ''the impact of the use of renewable fuels on other factors.''[38] Moreover, many other factors affect the statutory factors themselves. Accordingly, consistent with the statute, we have considered several other factors, including:

• The interaction between volume requirements for years 2023–2025, including the nested nature of those volume requirements and the availability of carryover RINs.[39]

• The ability of the market to respond given the timing of this rulemaking.[40]

• Our obligation to respond to the *ACE* remand (Section V).

• The supply of qualifying renewable fuels to U.S. consumers (Section III.A.5).[41]

• Soil quality (RIA Chapter 3.4).[42]

• Environmental justice (Section IV.E and RIA Chapter 8).[43]

• A comparison of costs and benefits (Section IV.D).[44]

*C. Statutory Conditions on Volume Requirements*

As indicated above, the CAA affords EPA flexibility to consider each of the enumerated factors and the weight to give those factors. However, the CAA does contain three conditions that affect our determination of the applicable volume requirements:

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

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

• A floor on the applicable volume of BBD.

1. Advanced Biofuel as a Percentage of Total Renewable Fuel

While the statute provides broad discretion in setting the applicable volume requirements for advanced biofuel and total renewable fuel, it also establishes a constraint on the relationship between these two volume requirements, and this constraint has implications for the implied volume requirement for conventional renewable fuel. The CAA provides that the applicable advanced biofuel requirement must ''be at least the same percentage of the applicable volume of renewable fuel as in calendar year 2022,''[45] meaning that EPA must, at a minimum, maintain the ratio of advanced biofuel to total renewable fuel that was established for 2022 for the years in which EPA sets the applicable volume requirements. In effect, this limits the implied volume of conventional renewable fuel within the

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

[27] In furtherance of this requirement, we have had periodic discussions with DOE and USDA on this action. These have occurred with agency staff throughout the proposal and final rule process, as well as through the OMB interagency process. An additional memorandum documenting discussions with the Administrator and Secretaries is also available in the docket for this action.

[28] CAA section 211(o)(2)(B)(ii)(I).

[29] CAA section 211(o)(2)(B)(ii)(II).

[30] CAA section 211(o)(2)(B)(ii)(III).

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

[32] CAA section 211(o)(2)(B)(ii)(V).

[33] CAA section 211(o)(2)(B)(ii)(VI).

[34] See *Nat'l Wildlife Fed'n* v. *EPA,* 286 F.3d 554, 570 (D.C. Cir. 2002) (analyzing factors within the Clean Water Act); accord *Riverkeeper, Inc.* v. *U.S. EPA,* 358 F.3d 174, 195 (2d Cir. 2004) (same); *BP Exploration & Oil, Inc.* v. *EPA,* 66 F.3d 784, 802 (6th Cir. 1995) (same); see also *Brown* v. *Watt,* 668 F.3d 1290, 1317 (D.C. Cir. 1981) (''A balancing of factors is not the same as treating all factors equally. The obligation instead is to look at all factors and then balance the results. The Act does not mandate any particular balance, but vests the Secretary with discretion to weigh the elements . . . .'') (addressing factors articulated in the Out Continental Shelf Lands Act).

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

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

[37] RFS Annual Rules Response to Comments Document at 10.

[38] CAA section 211(o)(2)(B)(ii)(VI).

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

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

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

[42] Soil quality is closely tied to water quality and is also relevant to the impact of renewable fuels on the environment more generally, such that this analysis also informs our analysis of the statutory factor ''the impact of the production and use of renewable fuels on the environment.'' CAA section 211(o)(2)(B)(ii)(I).

[43] Addressing environmental justice involves assessing the potential for the use of renewable fuels to have a disproportionate and adverse health or environmental effect on minority populations, low-income populations, tribes, and/or indigenous peoples.

[44] The comparison of costs and benefits compares our quantitative analysis of various statutory factors, including costs and energy security.

[45] CAA section 211(o)(2)(B)(iii).

total renewable fuel volume for years after 2022.

The applicable advanced biofuel volume requirement is 5.63 billion gallons for 2022.[46] The total renewable fuel volume requirement for 2022 is 20.63 billion gallons, resulting in an implied conventional volume requirement of 15 billion gallons. For 2022, then, advanced biofuel would represent 27.3 percent of total renewable fuel. The volume requirements we are finalizing in this action for 2023–2025, shown in Table I.A.1–1, all exceed this 27.3 percent minimum, and thus the applicable volume requirements that we are finalizing satisfy this statutory criterion.

2. Cellulosic Biofuel

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.[47] We interpret this requirement to mean that we must establish the cellulosic volume requirement at a level that is achievable and 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).[48] CAA section 211(o)(7)(D) provides that if ''the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under paragraph (2)(B),'' EPA ''shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year.'' Therefore, we are setting the volume requirements such that the mandatory waiver of the cellulosic volume is not anticipated to be triggered in those future years. Operating within this limitation, and in light of our consideration of the statutory factors explained in Section VI, we are setting the cellulosic volumes for 2023, 2024, and 2025 at the projected volume available in each year, respectively, consistent with our past actions in determining the cellulosic biofuel volume.[49] These projections, discussed further in Sections III.B.1 and VI.A, represent our best efforts to project the growth in the volume of these fuels that can be achieved in 2023–2025.

3. Biomass-Based Diesel

EPA has established the BBD requirement under CAA section 211(o)(2)(B)(ii) since 2013 because the statute only provided BBD volume targets through 2012. The statute also requires that the BBD volume requirement be set at or greater than the 1.0 billion gallon volume requirement for 2012 in the statute, but does not provide any other numerical criteria that EPA is to consider.[50] EPA is setting the BBD volume requirement for 2023, 2024, and 2025 at 2.82, 3.04, and 3.35 billion gallons respectively. These volumes are significantly greater than 1.0 billion gallon minimum requirement for these years.

*D. Authority To Establish Volumes and Percentage Standards for Multiple Future Years*

EPA is finalizing volume and percentage standards for 2023, 2024, and 2025 in this single action. In the proposed rule, we sought comment on volume requirements for 2026, and proposed volumes for 2023, 2024, and 2025. We also proposed corresponding percentage standards for 2023, 2024, and 2025.

In the proposal, we discussed how the number of years for which we might establish standards, and thus the numbers of years for which we must analyze the impacts of those standards, represented a tension between providing certainty for stakeholders of future demand and being able to project renewable fuel supply with reasonable certainty. We discussed how we focused our assessment of renewable fuel supply on the three years immediately following the end of the statutory volume targets (*i.e.,* 2023–2025) as an attempt to find a balance between these opposing concerns. Additionally, we have considered the statutory deadlines from promulgating applicable volumes, two of which have already passed (October 31, 2021, for 2023 applicable volumes, and October 31, 2022, for 2024 applicable volumes). The statutory deadline for promulgating the 2025 applicable volumes is later this year on October 31, 2023. Establishing volume requirements for three years strikes an appropriate balance between these opposing concerns.

We acknowledge that establishing volume targets and the associated percentage standards for a greater number of years would increase market certainty for obligated parties, biofuel producers, and other RIN market participants. However, the uncertainty inherent in making future projections increases for longer timeframes. Moreover, our experience with the RFS program since its inception is that unforeseen market circumstances involving not only renewable fuel supply but also relevant economics mean that fuels markets are continually evolving and changing in ways that cannot be predicted. These facts affect all supply-related elements of biofuel: projections of production capacity, availability of imports, rates of consumption, availability of qualifying feedstocks, and the gasoline and diesel demand projections that provide the basis for the calculation of percentage standards. Greater uncertainty in future projections means a higher likelihood that those future projections could turn out to be inaccurate, leading to the potential need to revise them after they are established through, for instance, one of the statutory waiver provisions. Such actions to revise applicable standards after they have been set could be expected to increase market uncertainty.

Promulgating standards for three years in a single action also increases the likelihood that we can meet the statutory deadline to promulgate applicable volumes by 14 months prior to the beginning of the calendar year. In this action, we are promulgating the 2025 volumes ahead of the statutory deadline of October 2023. Given the extensive analysis required to support the volumes, and the associated length of time necessary for CAA rulemaking actions, promulgating standards for multiple years facilitates compliance with the statutory requirements.

Many of the comments we received from stakeholders supported our proposal to establish standards for three years. While some stakeholders requested that standards be set for fewer than three years, others requested that we set standards for more than three years. Based on our desire to strengthen market certainty by establishing applicable standards for as many years as is practical, tempered by the knowledge that longer time periods increase uncertainty in projected volumes, increasing the potential that applicable standards might need to be waived at a later date, we continue to believe that three years represents an appropriate balance at this time. We are not making a determination in this action that three years is the appropriate number of years to establish standards under all circumstances and in all future actions. Indeed, it may be appropriate in future standard-setting

[46] 87 FR 39601.

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

[48] 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).

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

[50] CAA Section 211(o)(2)(B)(iv).

actions to establish standards for more or less than three years at a time.

The CAA requires EPA to promulgate regulations that, regardless of the date of promulgation, contain compliance provisions applicable to refineries, blenders, distributors and importers that ensure that the volumes in CAA section 211(o)(2)(B), which includes set volumes, are met.[51] As to setting percentage standards, for years after 2022, the CAA does not expressly direct EPA to continue to implement volume requirements through percentage standards established through annual rulemakings. Furthermore, in establishing volumes for years after 2022, EPA is directed to review ''the implementation of the program'' in years during which Congress provided statutory volumes.[52] Thus, Congress provided EPA discretion as to how to implement the volume requirements of the RFS program in years 2023 and beyond.

CAA section 211(o)(3)(B)(i) provides that by ''November 30 of each of calendar years 2005 through 2021, based on the estimate provided [by EIA], the Administrator . . . shall determine and publish in the **Federal Register**, with respect to the following calendar year, the renewable fuel obligation that ensures that the requirements of paragraph (2) are met.'' [53] The next clause (ii) provides further requirements for the obligation described in clause (i). On its face, this language does not apply to rulemakings establishing obligations for years subsequent to 2022. Therefore, EPA is not bound by this language for those years.

EPA could choose to continue to utilize the same procedures articulated in CAA section 211(o)(3)(B)(i) for establishing percentage standards for years beyond 2022. In that case, EPA would establish standards for 2023 in this rulemaking, and separately set standards for 2024 and 2025 in later actions. However, EPA has chosen to set percentage standards at one time for several future years (*i.e.,* for 2023, 2024, and 2025). Doing so increases certainty for obligated parties, renewable fuel producers, and RIN market participants, as both the applicable volume requirements and the associated percentage standards can be established in advance of the year in which they apply. This also provides certainty for obligated parties in determining compliance deadlines. The regulations at 40 CFR 80.1451(f)(1)(i)(A) provide that compliance will not be required for a given compliance year until after the percentage standards for the following year are established. Thus, establishing the percentage standards through this rulemaking process provides certainty as to the date of the compliance deadlines for 2022–2024. This action properly balances creating certainty for obligated parties, renewable fuel producers, and RIN market participants in establishing percentage standards and limiting the scope of uncertainty in projections of future gasoline and diesel consumption by setting percentage standards only for the next three compliance years.[54]

Several commenters supported EPA's proposal to establish volumes and associated percentage standards for 2023–2025. Other commenters suggested that EPA should only promulgate percentage standards for 2023 and 2024 because EPA could instead finalize the percentage standards for 2025 along with the 2026 volumes and percentage standards given the statutory deadline of October 31, 2024. We discuss responses to these comments in the RTC document.

In this action, we are finalizing applicable volume requirements and the associated percentage standards for 2023–2025, as described further in Sections VI and VII. We believe that establishing both the volume requirements and percentage standards for the next three years strikes an appropriate balance between improving the program by providing increased certainty over a multiple number of years and recognizing the inherent uncertainty in longer-term projections.

*E. Considerations for Late Rulemaking*

In this rulemaking, we are finalizing applicable volume targets for the 2023 and 2024 compliance years that miss the statutory deadlines.[55] EPA has in the past also missed statutory deadlines for promulgating RFS standards, including the BBD Standards in 2014–2016, which were established under CAA section 211(o)(2)(B)(ii), the same provision under which we are establishing the 2023 and 2024 standards. The U.S. Court of Appeals for the D.C. Circuit found that EPA retains authority to promulgate volumes and annual standards beyond the statutory deadlines, even those that apply retroactively, so long as EPA exercises this authority reasonably.[56] In doing so, EPA must balance the burden on obligated parties of a delayed rulemaking with the broader goal of the RFS program to increase renewable fuel use.[57] In upholding EPA's late and retroactive standards in *ACE,* the court considered several specific factors, including the availability of RINs for compliance, the amount of lead time and adequate notice for obligated parties, and the availability of compliance flexibilities. In addressing rulemakings that were late (*i.e.,* those issued after the statutory deadline) but not retroactive, the court emphasized the amount of lead time and adequate notice for obligated parties.[58] Most relevant here is EPA's action in 2015 that established the BBD volume requirements for 2014–2017.[59] There, EPA missed the statutory deadline, that EPA establish an applicable volume target for BBD no later than 14 months before the first year to which that volume requirement will apply, for all four years.[60] The court found that EPA properly balanced the relevant considerations and had provided sufficient notice to parties in establishing the applicable volume requirements for 2014–2017.[61] A commenter suggested that EPA is further limited on our promulgation of the 2023 and 2024 standards at no greater than the 2022 standards. We disagree for the reasons articulated in the RTC document.

In this rulemaking, we are exercising our authority to set the applicable renewable fuel volume requirements for 2023 and 2024 after the statutory deadline to promulgate volumes no later than 14 months before the first year to which those volume requirements apply.[62] This final rule will also be partly retroactive, as the 2023 standards are being finalized in the middle of the 2023 calendar year. Nevertheless, we believe that the 2023 standards being finalized in this action can be met and that the available RIN generation data from the first quarter of 2023 suggests the market is on track to supply the volumes we are finalizing for 2023 (see Section VI and RIA Chapter 6). We are finalizing the 2024 standards prior to

[51] CAA section 211(o)(A)(i), (iii).

[52] CAA Section 211(o)(2)(B)(ii).

[53] CAA Section 211(o)(3)(b)(i).

[54] *See Growth Energy* v. *Env't Prot. Agency,* 5 F.4th 1, 15 (D.C. Cir. 2021) (acknowledging deference to agency's predictive judgments).

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

[56] *Americans for Clean Energy* v. *EPA,* 864 F.3d 691 (D.C. Cir. 2017) (*ACE*) (EPA may issue late applicable volumes under CAA section 211(o)(2)(B)(ii)); *Monroe Energy, LLC* v. *EPA,* 750 F.3d 909 (D.C. Cir. 2014); *NPRA* v. *EPA,* 630 F.3d 145, 154–58 (D.C. Cir. 2010).

[57] *NPRA* v. *EPA,* 630 F.3d 145, 164–65.

[58] *ACE,* 864 F.3d at 721–22.

[59] 80 FR 77420, 77427–28, 77430–31 (Dec. 14, 2015).

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

[61] *ACE,* 864 F.3d at 721–23.

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

the beginning of the 2024 calendar year and do not expect those standards to apply retroactively. Additionally, we have provided obligated parties notice as of December 1, 2022 of the proposed 2023 and 2024 standards, a month ahead of when the 2023 standards would apply, and over a year in advance of when the 2024 standards would apply. Additionally, obligated parties will have at least nine months from the time of promulgation of this final rule before they are required to submit associated compliance reports for 2023.[63] There will additionally be approximately 22 months between the promulgation of this rule and the compliance deadline for the 2024 standards.[64] Additionally, all obligated parties will continue to have available compliance flexibilities such as carry forward deficits, and carryover RINs to comply with the 2023 and 2024 standards.

In addition, in completing its response to the *ACE* remand of the 2016 annual rule, we are establishing a supplemental standard for 2023.[65] This supplemental standard is being promulgated after the statutory deadline for the 2016 standards (November 30, 2015). However, the supplemental standard would prospectively apply to gasoline and diesel produced or imported in 2023, therefore is only partly retroactive. We further discuss our response to the *ACE* remand in Section V.

*F. Impact on Other Waiver Authorities*

While we are establishing applicable volume requirements in this action for future years that are achievable and appropriate based on our consideration of the statutory factors, we retain our legal authority to waive volumes in the future under the waiver authorities should circumstances so warrant.[66] For example, the general waiver authority under CAA section 211(o)(7)(A) provides that EPA may waive the volume targets in ''paragraph (2),'' which provides both the statutory applicable volume tables and EPA's set authority (the authority to set applicable volumes for years not specified in the table). Therefore, similar to our exercise of the waiver authorities to modify the statutory volumes in past annual standard-setting rulemakings, EPA has the authority to modify the applicable volumes for 2023 and beyond in future actions through the use of our waiver authorities to modify the applicable volumes we are setting in this action.

We note that, as described above, CAA section 211(o)(2)(B)(iv) requires that EPA set the cellulosic biofuel volume requirements for 2023 and beyond based on the assumption that the Administrator will not need to waive those volume requirements under the cellulosic waiver authority. Because we are, in this action, establishing the applicable volume targets for 2023–2025 under the set authority, we do not believe we could also waive those requirements using the cellulosic waiver authority in this same action in a manner that would be consistent with CAA section 211(o)(2)(B)(iv), since that waiver authority is only triggered when the projected production of cellulosic biofuel is less than the ''applicable volume established under [211(o)(2)(B)].'' In other words, it does not appear that EPA could use both the set authority and the cellulosic waiver authority to establish volumes at the same time in this action.

Establishing the volume requirements for 2023–2025 using our set authority apart from the cellulosic waiver authority has important implications for the availability of cellulosic waiver credits (CWCs) in these years. When EPA reduces cellulosic volumes under the cellulosic waiver authority, EPA is also required to make CWCs available under CAA section 211(o)(7)(D)(ii). In this rule we are, for the first time, establishing a cellulosic biofuel standard without utilizing the cellulosic waiver authority. We interpret CAA section 211(o)(7)(D)(ii) such that CWCs are only made available in years in which EPA uses the cellulosic waiver authority to reduce the cellulosic biofuel volume. Because of this, cellulosic waiver credits would not be available as a compliance mechanism for obligated parties in these years absent a future action to exercise the cellulosic waiver authority. We recognized this likelihood in the recent rule establishing volume requirements for 2020–2022, where we stated that CWCs were unlikely to be available in 2023 as part of our rationale for not requiring the use of cellulosic carryover RINs in setting the cellulosic volume requirements for 2020–2022. [67] Some commenters suggested that we should make CWCs available even in the absence of exercising our cellulosic waiver authority to provide a price cap on cellulosic volume, or to provide additional flexibility for obligated parties. As we do not find authority to issue cellulosic waiver credits without use of the cellulosic waiver authority, we will not be issuing CWCs absent a future waiver of the cellulosic standard. Despite the absence of CWCs, we expect that obligated parties will be able to satisfy their cellulosic biofuel obligations for these years because we are proposing to establish the cellulosic biofuel volume requirement based on the quantity of cellulosic biofuel we project will be produced and imported in the U.S. each year.

*G. Severability*

As stated in the proposal, we intend for the volume requirements and percentage standards for each single year covered by this rule (*i.e.,* 2023, 2024, and 2025) to be severable from the volume requirements and percentage standards for the other years. Each year's volume requirements and percentage standards are supported by analyses for that year. Similarly, we intend for the 2023 supplemental standard and percentage standard to be severable from the annual volume requirements and percentage standards.

We also intend for the other regulatory amendments to be severable from the volume requirements and percentage standard. The regulatory amendments are intended to improve the RFS program in general and are not part of EPA's analysis for the volume requirements and percentage standards for any specific year. Further, each of the regulatory amendments in Sections IX and X is severable from the other regulatory amendments because they all function independently of one another.

If any of the portions of the rule identified in the preceding paragraph (*i.e.,* volume requirements and percentage standards for a single year, the 2023 supplemental standard, the individual regulatory amendments) is invalidated by a reviewing court, we intend the remainder of this action to remain effective as described in the preceding paragraph. To further illustrate, if a reviewing court were to invalidate the volume requirements and percentage standards and supplemental standard, we intend the other regulatory amendments to remain effective. Or, as another example, if a reviewing court invalidates the BBD conversion factor provisions, we intend the volume requirements and percentage standards as well as the supplemental standard and other regulatory amendments to remain effective.

[63] EPA expects the 2023 compliance deadline to be March 31, 2024. See 40 CFR 80.1451(f)(1)(A).

[64] The 2024 compliance deadline is March 31, 2025. 40 CFR 80.1451(f)(1)(A).

[65] We also established a supplemental standard for 2022 in a prior action. See, *e.g.,* 87 FR 39600 (July 1, 2022).

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

[67] 87 FR 39616 (July 1, 2022).

**III. Candidate Volumes and Baselines**

The statute requires that we analyze a specified set of factors in making our determination of the appropriate volume requirements to establish for years after 2022, and further requires that we review implementation of the program in prior years. The statutory factors are listed in Section II.B. Because many of those factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract, we have therefore opted to analyze those factors based on specific ''candidate volumes'' for each category of renewable fuel. To accomplish this, we first derived a set of renewable fuel volumes from the statutory factors most closely related to renewable fuel supply and other relevant factors. The development of these candidate volumes helps further our consideration of the statutory factor to analyze the expected annual rate of future commercial production of renewable fuels and provide us with renewable fuel volumes with which to perform the remaining analyses required by the statute. We used these candidate volumes to conduct analyses of the other environmental and economic factors. Finally, we determined, based on the results of all of the analyses (those that went into developing the candidate volumes, described in this section, and the subsequent analyses performed using these candidate volumes, described in Sections IV and VI), the volume requirements that would be appropriate to establish. Our approach can be summarized as a three-step process:

1. Development of candidate volumes (described in this section).

2. Multifactor analysis based on those candidate volumes (described in Section IV).

3. Determination of applicable volume requirements based on a consideration of all factors analyzed (described in Section VI).

We acknowledge that we are taking a different approach to developing candidate volumes in this rule than we did under the reset authority in the 2020–2022 rule. The primary difference is that in the 2020–2022 rule the candidate volumes for non-cellulosic advanced biofuel and conventional renewable fuel were generally in the implied statutory volumes for these fuel types in comparison to the statutory volumes. In this rule we are establishing volumes for 2023–2025, a time period for which there are no statutory targets. We therefore developed the candidate volumes for non-cellulosic biofuel and conventional biofuel based primarily on a consideration of supply-related factors, with a consideration of other relevant factors as noted in the following sections. This approach is generally consistent with the approach we took for developing the candidate cellulosic biofuel volumes in the 2020–2022 rule, as the statutory cellulosic biofuel volumes were far beyond the quantity of these fuels that could be supplied.

For the first step in this process, we analyzed a subset of the statutory factors that are most closely related to supply of and demand for renewable fuel. These supply-and-demand-related factors (hereinafter ''supply-related factors'') [68] include the production and use of renewable fuels (as a necessary prerequisite to analyzing their impacts under CAA section 211(o)(2)(B)(ii)(I), (II), (V), and (VI))), the expected annual rate of future commercial production of renewable fuels (CAA section 211(o)(2)(B)(ii)(III)), and the sufficiency of infrastructure to deliver and use renewable fuel (CAA section 211(o)(2)(B)(ii)(IV)). Consideration of these supply-related statutory factors necessarily included a consideration of imports and exports of renewable fuel, consumer demand for renewable fuel, the availability of qualifying feedstocks, and other relevant factors as discussed in the following sections. Since the statute also requires us to review the implementation of the program in prior years, an analysis of renewable fuel supply includes not just projections for the future but also an assessment of the historical supply of renewable fuel. While we focused on supply-related factors, as discussed further in the following sections we also considered other information such as trends in statutory volumes, GHG reduction implications, and market expectations resulting from our proposed rule.

This section describes the derivation of ''candidate volumes'' based on a consideration of supply-related factors as the first step in our consideration of all factors that we are required to analyze under the statute. The candidate volumes represent those volumes that might be reasonable to require based on the supply-related factors, but which have not yet been evaluated in terms of the other economic and environmental factors. Basing the candidate volumes primarily on supply-related considerations is a reasonable first step because doing so narrows the scope for the multifactor analysis in a commonsense way. This step better enables our analysis of the remaining statutory factors. The candidate volumes we have identified in this final rule are similar to, but slightly higher than the candidate volumes in the proposed rule. Specifically, the candidate cellulosic biofuel volumes are higher for all three years (after accounting for the fact that we are not finalizing the proposed eRIN provisions in this rule). The candidate volumes for non-cellulosic advanced biofuels in this final rule are higher than the candidate volumes from the proposed rule for 2023–2025. Finally, the candidate volumes for conventional biofuel in this final rule are lower than the candidate volumes in the proposed rule for all three years, due to lower projected gasoline consumption. Section VI provides our rationale for the final volume requirements in light of all the analyses that we conducted.

In this final rule we updated the candidate volumes after considering the comments we received on our proposed rule as well as additional data not available at the time the analyses for the proposed rule were completed. We received many comments on the supply-related factors that informed the candidate volumes, including comments related to renewable fuel production capacity, the availability of feedstocks to produce renewable fuel, the quantity of renewable fuel that can be consumed in the transportation sector, and the ability for the incentives provided by the RFS program to incentivize increased renewable fuel production and use. These comments, along with more recent data, led us to increase the candidate volumes for CNG/LNG derived from biogas, ethanol produced from corn kernel fiber, biomass-based diesel, and other advanced biofuels projected to be produced or imported in 2023–2025, and corresponding increases to the candidate volumes for these fuel types relative to the proposal. Our consideration of comments on the proposed rule and additional data also resulted in slight decreases to the candidate volumes of conventional renewable fuel for 2023–2025.

Our updated projections of projected renewable fuel production and imports, including a brief discussion of the

[68] We use this shorthand (''supply-related factors'') only for ease of explanation in the context of identifying candidate volumes for analysis under CAA section 211(o)(2)(B)(ii). We recognize that this shorthand (''supply-related factors'') utilizes the term ''supply'' in a manner that is incongruent with the D.C. Circuit's interpretation of the scope of the term ''supply'' in the general waiver authority provision in CAA section 211(o)(7)(A). *ACE,* 864 F.3d at 710. (holding that the term ''inadequate domestic supply'' under the general waiver authority excludes ''demand-side factors''). References to ''supply-related factors'' in the context of our discussion of the candidate volumes for analysis under CAA section 211(o)(2)(B)(ii) have no bearing on our interpretation of the term ''inadequate domestic supply'' under the general waiver authority under CAA section 211(o)(7)(A).

relevant comments and new data that informed these projections, can be found in Section III.B. Section III.C summarizes the candidate volumes we analyzed. Finally, Sections III.D and III.E describe, respectively, the No RFS baseline that we believe would be the most appropriate point of reference for the analysis of the other statutory factors, and the volume changes calculated in comparison to that baseline.

*A. Scope of Analysis*

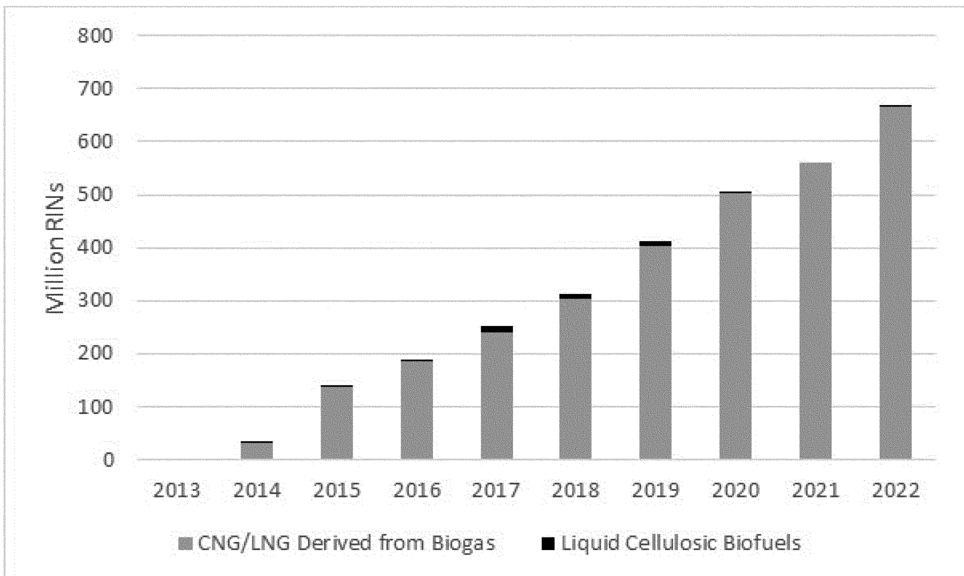
In Section II.D we discuss our statutory authority to establish RFS volumes and percentage standards for multiple years in a single rule. As discussed in that section, in this final rule we are establishing volumes and percentage standards for three years, 2023–2025. Consistent with this decision, Sections III.B and III.C discuss our determination of the candidate volumes for each year covered by this rule.

*B. Production and Import of Renewable Fuel*

1. Cellulosic Biofuel

Cellulosic biofuel is defined as renewable fuel derived from any cellulose, hemi-cellulose, or lignin that has lifecycle greenhouse gas emissions that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.[69] In the past several years, production of cellulosic biofuel has continued to increase. Cellulosic biofuel production reached record levels in 2022, driven by compressed natural gas (CNG) and liquified natural gas (LNG) derived from biogas. This section describes our assessment of the rate of production of qualifying cellulosic biofuel from 2023 to 2025, and some of the uncertainties associated with these volumes. Further detail on our projections of the rate of cellulosic biofuel production and import can be found in RIA Chapter 6.1.

**Figure III.B.1-1: Cellulosic Biofuel RINs Generated (2013–2022)**




a. CNG/LNG Derived From Biogas

To be eligible to generate RINs for CNG/LNG derived from biogas, biogas from qualifying sources first must be collected and upgraded to enable its use in CNG/LNG vehicles. This upgrading process involves removing undesirable components and contaminants from biogas. Biogas that has been upgraded and distributed via a closed, private distribution system is called ''treated biogas'' while biogas that has been upgraded and distributed via the natural gas commercial pipeline system is referred to as renewable natural gas (RNG). RNG is essentially indistinguishable from fossil-based natural gas and can be used interchangeably and transported through the same pipelines. While treated biogas is typically used to fuel CNG/LNG vehicles at the site where it is produced, RNG is injected into the natural gas commercial pipeline system. Once injected into the natural gas commercial pipeline system, RNG can be used in a variety of applications, including to fuel CNG/LNG vehicles, for generating electricity, for residential heating, and for other industrial or commercial purposes.

In the proposed rule we projected the use of CNG/LNG produced from RNG[70] in 2023–2025 using an industry-wide projection of the rate of growth calculated from RIN generation over the previous 24 months. While some commenters argued that EPA should project future production of CNG/LNG from RNG based on a facility-by-facility assessment, many supported the proposed methodology of using an industry-wide rate of growth to project production in future years. Many of the commenters who generally supported the rate of growth approach, however, requested that EPA use a higher rate of growth that considered data beyond just the most recent 24 months. These comments are discussed briefly at the end of this section, and in greater detail in the RTC document. In this final rule we are using an industry-wide rate of growth based on RIN generation data

[69] 40 CFR 80.1401.

[70] We note that as described in the biogas regulatory reform provisions in Section IX, we define RNG to mean biogas that has been upgraded to commercial pipeline quality and placed onto the natural gas commercial pipeline system. We also define the term ''treated biogas'' to refer to biogas that has undergone treatment for use as transportation fuel but that is not placed onto the natural gas commercial pipeline system (*i.e.*, it is distributed via a closed, private distribution system). For purposes of this section of the preamble, we use the term RNG to refer collectively to treated biogas and RNG.

from 2015–2022 to project the production and use of RNG as CNG/LNG. As discussed later in this section, we believe the growth rate calculated using data from 2015–2022 better reflects the potential production and use of RNG as CNG/LNG through 2025. This results in a significantly higher rate of grow in the final rule (25.0%) relative to the proposed rule (13.1%), and higher projected volumes of RNG use as CNG/LNG for each year from 2023–2025.

In projecting the production and use of RNG used as CNG/LNG in 2023–2025 we primarily considered two potential limiting factors. The first factor considered was the quantity of RNG we project will be produced from qualifying biogas in 2023–2025. Because biogas must be upgraded to enable its use in CNG/LNG vehicles, the quantity of RNG that we project will be produced sets a maximum for the quantity of biogas that can be used in vehicles as CNG/LNG. The second major factor we consider is the quantity of RNG that is capable of being used as transportation fuel in CNG/LNG vehicles. As discussed above, RNG can be used in many different applications and a variety of factors, including limitations related to the demand for CNG/LNG from vehicles, fueling infrastructure, and demand for RNG from other sectors can all impact the quantity of CNG/LNG used in vehicles. Our projection of the quantity of RNG used as CNG/LNG that will be produced and used in 2023–2025 is described briefly in this section, and in greater detail in RIA Chapter 6.1.3.

To project qualifying RNG production for this final rule we used an industry wide projection approach that is similar, though not identical, to the approach used to project the production of RNG used as CNG/LNG in previous RFS rules as well as in the proposed rule. While the approach we are using to project the production of CNG/LNG is similar to the approach used in previous years and the proposal, we are now using a broader range of data to calculate the growth rate used to project future projection. This reflects our consideration of an appropriate growth rate following engagement with stakeholders and review of both new data and commenter submissions on the proposal. More detail on our consideration of the appropriate rate of growth is provided later in this section. 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 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.

To project the production of qualifying RNG we calculated a year-over-year growth rate and applied this growth rate to the total production of RNG used as CNG/LNG in 2022 (the most recent year for which complete data are available). To calculate the year-over-year growth rate we considered RIN generation data for RNG used as CNG/LNG from 2015–2022 instead of just the most recent 24 months for the proposal. We believe a rate of growth based on this larger set of data better reflects the potential for RNG production in 2023–2025. We also note that this rate of growth is within the range of the growth rates suggested by RNG producers in the public comment period (generally 20–30%) and closer to, though still less than, estimated RNG production from the Coalition for Renewable Natural Gas based on their analysis of new RNG facilities under construction and in development.[71] The data used to calculate the projected rate of growth for RNG and the resulting projections of RNG production in 2023–2025 are shown in Table III.B.1.a–1 and Table III.B.1.a–2.

TABLE III.B.1.a–1—GENERATION OF CELLULOSIC BIOFUEL RINS FOR RNG USED AS CNG/LNG

[Ethanol-equivalent gallons]

| 2015 RIN generation (million RINs) | 2022 RIN generation (million RINs) | Year-over-year increase (%) |
|---|---|---|
| 139.9 | 666.1 | 25.0 |

TABLE III.B.1.a–2—PROJECTED GENERATION OF QUALIFYING RNG

[Ethanol-equivalent gallons]

| Year | Date type | Growth rate (%) | Volume (million RINs) |
|---|---|---|---|
| 2022 | Actual | N/A | 665 |
| 2023 | Projection | 25.0 | 831 |
| 2024 | Projection | 25.0 | 1,039 |
| 2025 | Projection | 25.0 | 1,299 |

We next considered how much of the qualifying RNG produced in 2023–2025 could be used as transportation fuel in the form of CNG/LNG. While the volumes of RNG use as CNG/LNG in Table III.B.1.a–2. appear to be approaching the upper limit (estimated to be 1.4–1.75 billion ethanol-equivalent gallons) of all CNG/LNG capable of being used as transportation fuel in 2023–2025 in CNG/LNG vehicles in the fleet, these 2023–2025 volumes are still below the total quantity of CNG/LNG projected to be used as transportation fuel in 2023–2025.[72] Thus, the entire quantity of qualifying RNG produced in 2023–2025 could still be used as transportation fuel and be able to generate RINs under the RFS program. We therefore used the volumes in Table III.B.1.a–2 as the candidate volumes for RNG use as CNG/LNG in 2023–2025.

We received many comments on our projected volume for RNG used as CNG/LNG in our proposed rule. While some commenters supported the proposed volumes, many stakeholders involved in

[71] Further discussion of the growth rate used to project the production of CNG/LNG derived from biogas, and our reasons for considering data beyond the most recent 24 months, can be found in RTC Section 3.2.2.

[72] See RIA Chapter 6.1.3 for a further discussion of our estimate of CNG/LNG used as transportation fuel in 2023–2025.

the production, distribution, and use of RNG as CNG/LNG stated that the projected volumes were too low. In particular, they stated that the growth in RNG use as CNG/LNG in recent years was significantly impacted by the COVID pandemic and did not reflect projected growth in this industry through 2025. Some commenters also noted significant investment in expanding RNG production which they claimed supported a much higher growth rate in the projected volume of biogas used in CNG/LNG vehicles.[73]

In this final rule we used a growth rate based on a longer time-period (2015–2022) than in both our proposed rule and previous RFS rules. We believe the higher growth rate that results from using additional data better reflects the likely production of RNG use as CNG/LNG in 2023–2025 than using a growth rate based on the last 24 months of data. Using data from 2015–2022 strikes a balance between using the most recent data available and not focusing exclusively on data from the last 24 months, during which the industry may still have been recovering from the impacts of the COVID pandemic. As noted earlier, the growth rate that results from using this additional data is supported by the public comments (which generally requested that EPA use growth rates that ranged from 20 to 30 percent), as well as the data received during the public comment period on the large number of RNG production facilities that are currently under construction or in the project development phase. Finally, we note that the limited data available from early 2023 suggest that 25% growth is achievable in 2023.[74]

b. Ethanol From Corn Kernel Fiber

While there are several different technologies currently being developed to produce liquid fuels from cellulosic biomass, these technologies are by and large highly unlikely to produce significant quantities of cellulosic biofuel by 2025. One exception is the production of ethanol from corn kernel fiber (CKF), for which several different companies have developed processes. Many of these processes involve co-processing of both the starch and cellulosic components of the corn kernel making it difficult to quantify what portion of the ethanol they produce is from cellulosic biomass.

In the proposed rule we noted the potential for the production of cellulosic ethanol from CKF in 2023–2025. We did not, however, project any production of ethanol from CKF in 2023–2025 beyond the few facilities that were currently registered as cellulosic biofuel producers. At the time of the proposal no facilities had yet requested to register as cellulosic biofuel producers using analytical methods consistent with recently published guidance.[75] Since the proposal, however, a number of facilities have approached EPA with registration requests. In this final rule we are now projecting that the production of ethanol from CKF will increase from 7 million gallons in 2023 to 77 million gallons in 2025. These projections, which are described further in the remainder of this section and in greater detail in RIA Chapter 6.1 are based on projections of the number of facilities we expect will register as cellulosic biofuel producers and the expected rate of cellulosic biofuel production at each facility.

To be eligible to generate cellulosic RINs, facilities that are co-processing starch and cellulosic components of the corn kernel must be able to determine the amount of ethanol that is produced from the cellulosic portion of the corn kernel. This requires the ability to accurately and reliably calculate the amount of ethanol produced from the cellulosic portion as opposed to the starch portion of the corn kernel; EPA has to date had significant concerns with facilities' abilities to accurately perform this calculation. In September 2022 EPA published a document providing updated guidance on analytical methods that could be used to quantify the amount of ethanol produced when co-processing corn kernel fiber and corn starch. [76] This guidance highlighted several outstanding critical technical issues that need to be addressed.

Since issuing the proposed rule EPA has continued to have substantive discussions with technology providers intending to use analytical methods consistent with the guidance document and owners of facilities intending to register as cellulosic biofuel producers using these analytical methods. The technology providers have indicated that using analytical methods consistent with those in the guidance document they can demonstrate that approximately 1.5% of the ethanol produced from existing corn ethanol facilities is produced from cellulosic biomass.

Based on the information from the technology providers, we believe that 1.5% of cellulosic ethanol can generally be produced from corn kernel fiber at existing ethanol facilities with few, if any, additional processing units or process changes. We are aware that many ethanol facilities are working with the technology providers in order to register their facilities to produce cellulosic ethanol. We are therefore projecting volumes of ethanol from corn kernel fiber through 2025 that include production from facilities that have not yet registered as cellulosic biofuel producers, but are expected to do so during this time period. The projected production of cellulosic ethanol from CKF, shown in Table III.B.1.b-1, are based on projections of when facilities will register as cellulosic biofuel producers under the RFS program and begin producing fuel. The projection methodology for cellulosic ethanol production from CKF used in this final rule is discussed further in RIA Chapter 6.1.2.

TABLE III.B.1.b–1—PROJECTED PRODUCTION OF ETHANOL FROM CKF

[Ethanol-equivalent gallons]

| Year | Volume (million RINs) |
|---|---|
| 2023 | 7 |
| 2024 | 51 |
| 2025 | 77 |

c. Other

For the 2023–2025 timeframe, we expect that commercial scale production of cellulosic biofuel in the U.S. beyond CNG/LNG derived from biogas and ethanol produced from CKF will be very limited. There are several cellulosic biofuel production facilities in various stages of development, construction, and commissioning that may be capable of producing commercial scale volumes of cellulosic biofuel by 2025. These facilities generally are focusing on producing cellulosic hydrocarbons that could be blended into gasoline, diesel, and jet fuel from feedstocks such as separated municipal solid waste (MSW) and slash, precommercial thinnings, and tree residue. In light of the fact that no parties have achieved consistent production of liquid cellulosic biofuel

[73] See RTC Section 3.2.2 for a summary of these comments and a more detailed response.

[74] Further discussion of the growth rate used to project the production of CNG/LNG derived from biogas, and our reasons for considering data beyond the most recent 24 months, can be found in RTC Section 3.2.2.

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

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

in the U.S. or consistently exported liquid cellulosic biofuel to the U.S., production and import of liquid cellulosic biofuel in 2023–2025 is highly uncertain and likely to be relatively small (see RIA Chapter 6.1.4 for more detail on the potential production of liquid cellulosic biofuel through 2025). For the candidate volumes we have projected no production of these fuels in 2023–2025.

d. eRINs

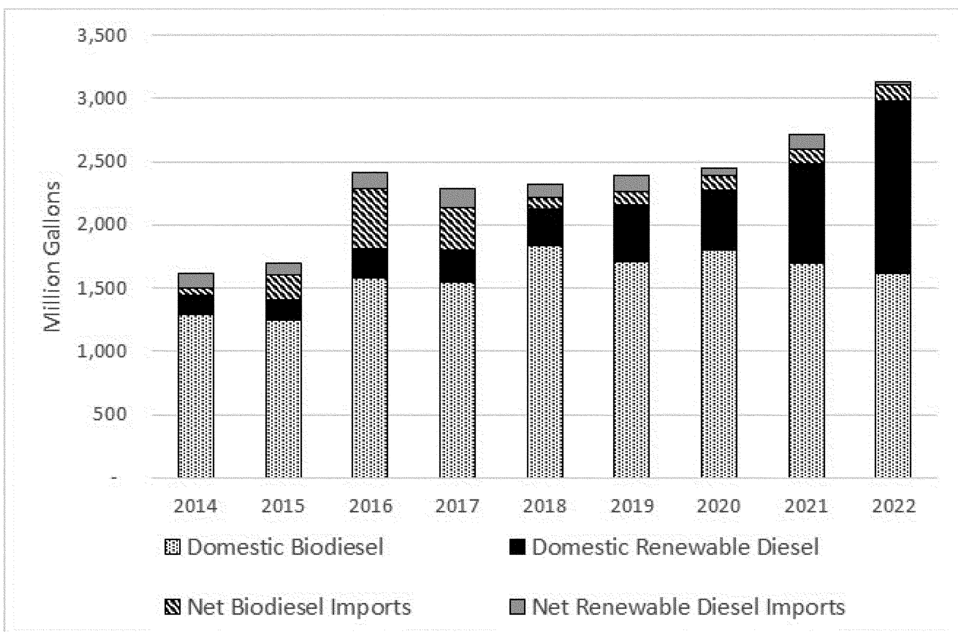
As noted in the Executive Summary, we are not finalizing the proposed revisions to the eRIN program in this rulemaking. We are therefore not including any volume from renewable electricty in our projections of the production and import of cellulosic biofuel. eRINs were projected to be a significant source of cellulosic biofuel in the proposed rule in 2024 and 2025 (representing 600 million and 1.2 billion RINs in 2024 and 2025 respectively). Because we no longer included projected volumes of eRINs, our projections of the production and imports of total cellulosic biofuel for 2024 and 2025 in this final rule are lower than the proposed rule, despite the higher projections for RNG used in vehicles as a renewable form of CNG/LNG and ethanol produced from CKF in this final rule.

2. Biomass-Based Diesel

Since 2010, when the BBD volume requirement was added to the RFS program, production of BBD has generally increased year-on-year. The volume of BBD supplied in any given year is influenced by a number of factors, including: production capacity, feedstock availability and cost, available incentives including the RFS program, the availability of imported BBD, the demand for BBD in foreign markets, and several other economic factors.

The vast majority of fuel that qualifies as BBD is biodiesel and renewable diesel. Both these fuels are produced from animal fat and vegetable oils and are replacements for diesel fuel, however they differ in their production processes and chemical composition. Biodiesel is an oxygenated fuel that is generally produced using a transesterification process. Renewable diesel is a hydrocarbon fuel that closely resembles petroleum diesel that is generally produced by hydrotreating renewable feedstocks. From 2010 through 2015 the vast majority of BBD supplied to the U.S. was biodiesel. While biodiesel is still the largest source of BBD supplied to the U.S., the supply of renewable diesel in 2022 was nearly as large as the supply of biodiesel, and the supply of renewable diesel is projected to exceed the supply of biodiesel in future years as renewable diesel production and imports continue to grow.

**Figure III.B.2-1: Biodiesel and Renewable Diesel Supply 2014–2022[a]**




[a] Numbers are based data from the EPA Moderated Transaction System (EMTS). This figure does not include the small quantity of jet fuel that was produced (less than 20 million gallons each year) or fuels that did not generate RINs. This figure also does not include advanced (D5) or conventional (D6) biodiesel and renewable diesel, which are discussed in Sections III.B.3 and III.B.4.b and RIA Chapters 6.3 and 6.7.

There are also very small volumes of renewable jet fuel and heating oil that qualify as BBD, and there are currently significant efforts underway to incentivize growth in renewable jet fuel in particular (often referred to as sustainable aviation fuel or SAF).[77] Jet fuel has qualified as a RIN-generating advanced biofuel under the RFS program since 2010, and must achieve at least a 50 percent reduction in GHGs in comparison to petroleum-based fuels. The technology and feedstocks that can be used to produce SAF today are often the same as those currently used to produce renewable diesel. For example, the same process that produces renewable diesel from waste fats, oils, and greases or plant oils generally

[77] According to EMTS data renewable jet fuel supply has ranged from 0–15 million gallons per year from 2014–2022. Jet fuel is eligible to generate RINs per 40 CFR 80.1426(a)(1)(iv), provided all other regulatory requirements are met.

produces hydrocarbons in the distillation range of jet fuel that can be separated and sold as SAF instead of being sold as renewable diesel. While relatively little SAF has been produced since 2010—less than 15 million gallons per year—opportunities for increasing this category of advanced biofuel exist. A new tax credit for SAF, which was included in the Inflation Reduction Act, may result in increasing volumes of SAF produced from existing renewable diesel production facilities. SAF production from existing renewable diesel facilities would increase the amount of renewable fuel available for a transportation sector that may be otherwise particularly difficult to reduce carbon intensity; however, it would likely result in a decrease in renewable diesel production, with little or no net change in their overall production of RIN-generating fuels.[78] In this rule we have not separately projected growth in SAF production, but we recognize that some of the projected growth in renewable diesel production may instead be SAF from the same production facilities. Other SAF production technologies and production facilities also being developed could enable the future production of SAF from new facilities and feedstocks that are not expected to impact renewable diesel production.

In addition, in April 2022 the Biden Administration announced a new Sustainable Aviation Fuel Grand Challenge to inspire the dramatic increase in the production of sustainable aviation fuels to at least 3 billion gallons per year by 2030. This effort is accompanied by new and ongoing funding opportunities to support sustainable aviation fuel projects and fuel producers totaling up to $4.3 billion.

The remainder of this section provides historical data on biodiesel and renewable diesel production and production capacity, briefly discusses potential feedstock limitations for biodiesel and renewable diesel production in future years, and summarizes our assessment of the rate of production and use of qualifying BBD from 2023 to 2025, and some of the uncertainties associated with those volumes. Our assessments of production capacity, available feedstocks, and likely future production of biodiesel and renewable diesel in this final rule reflect our consideration of the comments we received on this rule as well as updated data not available at the time of the proposed rule. Our projections of the likely future production of biodiesel and renewable diesel in this final rule are higher than in the proposed rule, particularly in 2025 due to higher projections of feedstock availability. Further details on these volume projections can be found in RIA Chapter 6.2.

a. Biodiesel

Historically, the largest volumes of biomass-based diesel and advanced biofuel supplied in the RFS program have been biodiesel. Domestic biodiesel production increased from approximately 1.3 billion gallons in 2014 to approximately 1.8 billion gallons in 2018. Since 2018 domestic biodiesel production decreased slightly, to approximately 1.6 billion gallons in 2022. The U.S. has also imported significant volumes of biodiesel in previous years and has been a net importer of biodiesel since 2013. Biodiesel imports reached a peak in 2016 and 2017, with the majority of the imported biodiesel coming from Argentina.[79] In August 2017, the U.S. announced tariffs on biodiesel imported from Argentina and Indonesia.[80] These tariffs were subsequently confirmed in April 2018.[81] Since that time no biodiesel has been imported from Argentina or Indonesia, and net biodiesel imports have been relatively small.

Available data suggests that there is significant unused biodiesel production capacity in the U.S., and thus domestic biodiesel production could grow without the need to invest in additional production capacity. Consistent with comments we received on the rule, we have updated our assessment of domestic biodiesel production capacity using the latest information available from EIA. Data reported by EIA shows that biodiesel production capacity in January 2023 was approximately 2.05 billion gallons per year.[82] According to EIA data biodiesel production capacity grew slowly from about 2.1 billion gallons in 2012 [83] to a peak of approximately 2.5 billion gallons in 2018.[84] EIA reports that domestic biodiesel production capacity was approximately 2.5 billion gallons as recently as October 2021.[85] This facility capacity data is collected by EIA in monthly surveys, which suggests that this capacity represents the production at facilities that are currently producing some volume of biodiesel and likely does not include inactive facilities that are far less likely to complete a monthly survey. EPA separately collects facility capacity information through the facility registration process. This data includes both facilities that are currently producing biodiesel and those that are inactive. EPA's data shows a total domestic biodiesel production capacity of 3.1 billion gallons per year in April 2022, of which 2.8 billion gallons per year was at biodiesel facilities that generated RINs in 2021. These estimates of domestic production capacity strongly suggest that domestic biodiesel production capacity is unlikely to limit domestic biodiesel production through 2025.

b. Renewable Diesel and SAF

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. Historically, greater incentives have been available for renewable diesel production, which has caused many of these production facilities to maximize renewable diesel production. In the near term, we expect that any increase in SAF production will result in a corresponding decrease in renewable diesel production.[86] In this section we have focused on renewable diesel production, but we acknowledge that an increasing portion of this fuel may be used as SAF in future years.

Renewable diesel has historically been produced and imported in smaller quantities than biodiesel as shown in Figure III.B.2–1. In recent years, however, domestic production of renewable diesel has increased significantly. Renewable diesel production facilities generally have higher capital costs and production costs relative to biodiesel, which likely accounts for the much higher volumes

[78] The equivalence values for renewable diesel and jet fuel are similar, with renewable diesel generating 1.6–1.7 RINs per gallon depending on the energy content of the fuel and Jet fuel generally generating 1.6 RINs per gallon.

[79] EIA U.S. Imports by Country of Origin,*https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDB_im0_mbbl_a.htm.* According to EIA data, 67 percent of all biodiesel imports in 2016 and 2017 were from Argentina.

[80] 82 FR 40748 (Aug. 28, 2017).

[81] 83 FR 18278 (April 26, 2018).

[82] EIA Monthly Biofuels Feedstock and Capacity Update, *https://www.eia.gov/biofuels/update.* Mar. 31, 2023 ().

[83] EIA Monthly Biodiesel Production Report. February 2013.

[84] EIA Monthly Biodiesel Production Report. February 2019.

[85] EIA Monthly Biofuels Feedstock and Capacity Update. January 31, 2023 (*https://www.eia.gov/biofuels/update*).

[86] We recognize that new technologies are being developed to produce SAF from a wider variety of feedstocks. Production of SAF using these technologies would not negatively impact renewable diesel production. Through 2025, however, we expect that only relatively modest volumes of these fuels might be produced.

of biodiesel production relative to renewable diesel production to date. The higher cost of renewable diesel production can largely be offset through the benefits of economies of scale, since renewable diesel facilities tend to be much larger than biodiesel production facilities. More importantly, because renewable diesel more closely resembles petroleum-based diesel than biodiesel fuel (both renewable diesel and petroleum-based diesel are hydrocarbons while biodiesel is a methyl-ester) renewable diesel can be blended at much higher levels than biodiesel. This allows renewable diesel producers to benefit to a greater extent from the LCFS credits in California and other states in addition to the RFS incentives and the federal tax credit. The greater ability for renewable diesel to generate credits under California's LCFS program provides a significant advantage over biodiesel. Biodiesel blends in California containing 6 to 20 percent biodiesel require the use of an additive to comply with California's Alternative Diesel Fuels Regulations, making the use of higher level biodiesel blends more challenging in California.[87] We expect that an increasing number of states will adopt clean fuels programs, and that these programs could provide an advantage to renewable diesel production relative to biodiesel production in the U.S. See RIA Chapter 6.2 for further discussion.

Total domestic renewable diesel production capacity has increased significantly in recent years from approximately 280 million gallons in 2017 to approximately 2.9 billion gallons in January 2023.[88] Additionally, a number of parties have announced plans to build new renewable diesel production capacity with the potential to begin production by the end of 2025. This new capacity includes new renewable diesel production facilities, expansions of existing renewable diesel production facilities, and the conversion of units at petroleum refineries to produce renewable diesel.

We received numerous comments on the proposed rule related to renewable diesel production capacity. These comments generally cited projections that renewable diesel production capacity will grow significantly through 2025, and many of these comments cited data and projections from EIA. In this final rule we have updated our projection of renewable diesel production capacity through 2025 based on updated information from EIA, consistent with these comments. As in the proposed rule, however, we expect that renewable diesel production through 2025 will be limited to a level below production capacity primarily due to limited feedstock availability, which is further discussed later in Section III.B.2.c.

EIA currently projects that renewable diesel production capacity could reach nearly 6 billion gallons by 2025,[89] though it is possible that not all these announced projects will be completed, and not all of those that are completed will necessarily produce renewable diesel in the 2023–2025 timeframe addressed by this rule.[90] In previous years, domestic renewable diesel production has increased in concert with increases in domestic production capacity, with renewable diesel facilities generally operating at high utilization rates. In future years we expect that feedstock limitations will result in renewable diesel and biodiesel facilities operating below their production capacity. Competition for qualifying feedstocks could also result in reductions in biodiesel production if larger renewable diesel facilities are able to out-compete smaller biodiesel producers for feedstock.

In addition to domestic production of renewable diesel, the U.S. has also imported renewable diesel, with nearly all of it produced from FOG and imported from Singapore.[91] In more recent years, the U.S. has also exported increasing volumes of renewable diesel. Net imports of renewable diesel were approximately 120 million gallons in 2021 and 130 million gallons in 2022. This situation, wherein significant volumes of renewable diesel are both imported and exported, is likely the result of a number of factors, including the design of the biodiesel tax credit (which is available to renewable diesel that is either produced or used in the U.S. and thus eligible for exported volumes as well), the varying structures of incentives for renewable diesel (with the level of incentives varying depending on the feedstocks used to produce the renewable diesel varying as well as by country), and logistical considerations (renewable diesel may be imported and exported from different parts of the country). We are projecting that net renewable diesel imports will continue through 2025 at approximately the levels observed in recent years, as domestic producers export volumes to take advantage of both the U.S. tax incentives and other incentives abroad. However, we also recognize that increasing net imports of renewable diesel could be a significant source of additional renewable fuel supply in future years.

c. BBD Feedstocks

As was highlighted in the proposal, when considering the likely production and import of biodiesel and renewable diesel in future years, the availability of feedstock is a key consideration. We received many comments on our assessment of the availability of BBD feedstocks in the proposed rule. Many of these commenters stated that the data from USDA [92] that EPA used to project domestic soybean oil production through 2025 was not appropriate for this use. For this final rule we have updated our projections of soybean oil production in the U.S. and canola oil production in Canada through 2025. Our current projections of the production of these feedstocks are significantly higher than our projections in the proposed rule (which did not consider increased availability of canola oil from Canada [93]) and are generally in alignment with the projections provided by the commenters and discussions with market experts. As in our proposed rule, however, we continue to believe that the availability of qualifying feedstocks will serve to limit the production of biodiesel and renewable diesel through 2025. We also continue to believe that when evaluating the various statutory factors, the greatest benefits and fewest negative impacts of these fuels occur when increased production of these fuels is consistent with increased production of qualifying feedstocks produced in North America. Our assessment of available feedstocks (including our consideration of

[87] CARB Alternative Diesel Fuels Regulations Frequently Asked Questions. In 2021 nearly all renewable diesel consumed in the U.S. was consumed in California. Together renewable diesel and biodiesel represented approximately 26 percent of all diesel fuel consumed in California in 2021.

[88] 2017 renewable diesel capacity based on facilities registered in EMTS; January 2023 renewable capacity based on EIA March 2023 Monthly Biofuels Feedstock and Capacity Update.

[89] *Domestic renewable diesel capacity could more than double through 2025.* EIA Today in Energy. Feb. 2, 2023.

[90] Reuters. *CVR Pauses Renewable Diesel Plans as Feedstock Prices Surge.* August 3, 2021. Available at: *https://www.reuters.com/business/energy/cvr-pauses-renewable-diesel-plans-feedstock-prices-surge-2021-08-03.*

[91] EIA Monthly Renewable Diesel Imports by Country, available at *https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDO_im0_mbbl_m.htm.*

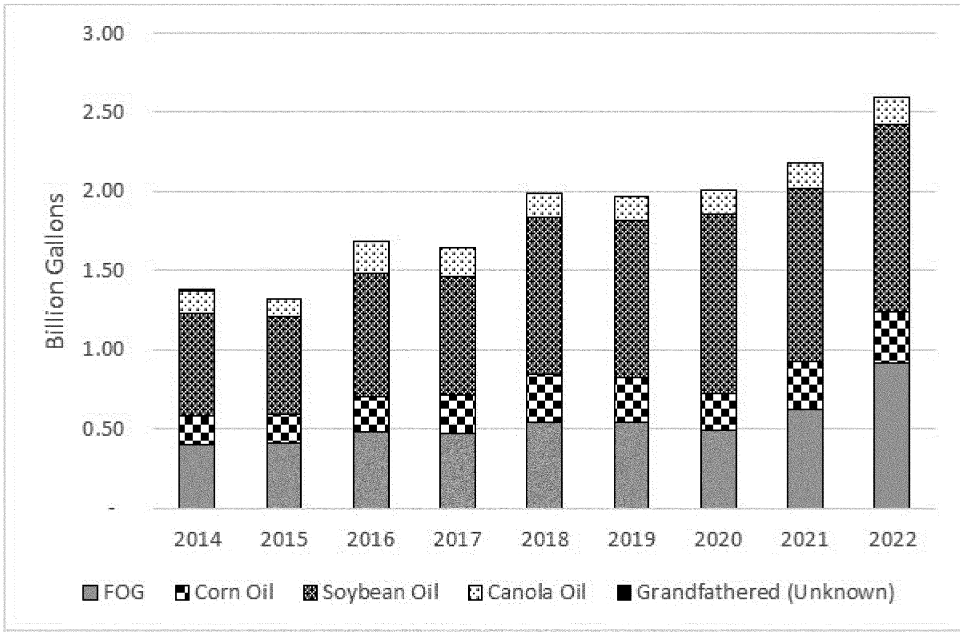
[92] USDA Agricultural Projections to 2031.

[93] Since the analyses for the proposed rule were conducted, EPA approved a pathway for renewable diesel produced from canola oil. In addition, Canadian feedstocks are covered by an aggregate compliance approach and are likely to be sourced from increased production of canola oil rather than diverted from existing uses. For a further discussion of the inclusion of canola oil from Canada in our projection of available feedstocks for biodiesel and renewable diesel production, see RTC Section 4.2.

comments on the proposed rule and data not available at the time of the proposed rule) is discussed briefly in this section, and in greater detail in RIA Chapter 6.2 and the RTC document.

Currently, biodiesel and renewable diesel in the U.S. are produced from a number of different feedstocks, including fats, oils and greases (FOG), distillers corn oil, and virgin vegetable oils such as soybean oil and canola oil. As domestic production of biodiesel has increased since 2014, an increasing percentage of total biodiesel production has been produced from soybean oil, with smaller increases in the use of FOG, distillers corn oil, and canola oil.

**Figure III.B.2-2: Feedstocks Used to Produce Biodiesel and Renewable Diesel in the U.S. 2014-2021**




Use of soybean oil to produce biodiesel increased from approximately 10 percent of all domestic soybean oil production in the 2009/2010 agricultural marketing year to 42 percent in the 2021/2022 agricultural marketing year.[94] In the intervening years, the total increase in domestic soybean oil production and the increase in the quantity of soybean oil used to produce biodiesel and renewable diesel were very similar, indicating that the increase in oil production was likely driven by the increasing demand for biofuel. However, as the production of renewable diesel has increased in recent years it appears that demand for soybean oil is growing faster than demand for soybean meal. Notably, the percentage of the soybean value that came from the soybean oil (rather than the meal and hulls) had been relatively stable and averaged approximately 33 percent from 2016–2020. The percentage of the soybean value that came from the soybean oil increased significantly starting in 2021, reaching a high of 53 percent in October 2021, before declining slightly to 43 percent in August 2022 (the most recent date for which data are available).

Through 2020, most of the renewable diesel produced in the U.S. was made from FOG and distillers corn oil, with smaller volumes produced from soybean oil. While many biodiesel production facilities are unable to use FOG and distillers corn oil, renewable diesel production facilities are generally able to use them. Additionally, nearly all the renewable diesel consumed in the U.S. is used in California due to the combined value of RFS and LCFS incentives (together with the blenders' tax credit). Under California's LCFS program renewable diesel produced from FOG and distillers corn oil receive more credits than renewable diesel produced from soybean oil.

Available volumes of FOG and distillers corn oil from domestic sources are expected to continue to increase in future years, but these increases are expected to be limited. FOG are the byproducts of other activities (rendering operations, for example), and production of FOG is not responsive to increasing demand for biofuel production. We therefore expect the availability of FOG to increase slowly, consistent with the observed trend in recent years. Similarly, distillers corn oil is a byproduct of ethanol production. Since we do not anticipate significant growth in ethanol production in future years, we do not project significant increases in the production of distillers corn oil for biofuel production, as most ethanol production facilities currently produce distillers corn oil. Therefore, if renewable diesel production in future years increases rapidly as suggested by the large production capacity announcements, it will likely require increased use of vegetable oils such as soybean oil and canola oil, increased use of imported feedstocks, or the use of feedstocks diverted from other markets.

Greater volumes of soybean oil are projected to be produced from new or expanded soybean crushing facilities. Several parties have announced plans to expand existing soybean crushing capacity and/or build new soybean crushing facilities.[95] This new crushing

[94] USDA Oil Crops Yearbook. March 2023.

[95] For example, see Demaree-Saddler, Holly, *Cargill plans US soy processing operations expansion,* World Grain, March 4, 2021; Sanicola, Laura, *Chevron to invest in Bunge soybean crushers*

Continued

capacity is expected to come online in the 2023–2025 timeframe. Increased crushing of soybeans in the U.S. will increase domestic soybean oil production. In this final rule we have updated our projections of domestic soybean oil production through 2025 to better reflect recent investments in domestic soybean crushing facilities that are expected to begin operating by 2025.

If domestic crushing of soybeans increases at the expense of soybean exports, domestic vegetable oil production could be increased without the need for additional soybean production. Alternatively, increased demand for soybeans from new or expanded crushing facilities could result in increased soybean production in the U.S or increasing volumes of qualifying feedstocks such as soybean oil and canola oil may be diverted from existing markets to produce renewable diesel, with non-qualifying feedstocks such as palm oil used in place of soybean and canola oil in food and oleochemical markets.

We also expect that production of canola oil will increase in future years due to expanding canola crushing capacity in Canada. Similar to the investments in soybean crushing in the U.S., a number of companies have announced investment in additional canola crushing capacity, and some of these projects are already under construction. Increasing canola oil production in Canada could provide an opportunity for domestic renewable diesel producers to import canola oil for biofuel production, however we expect that these parties will face competition for this feedstock from Canadian biofuel producers as well as food and other non-biofuel markets. The assessment of feedstock availability for this final rule (discussed in greater detail in RIA Chapter 6.2.3) includes volumes of imported canola oil we project could be available to domestic BBD producers.

d. Projected BBD Production and Imports

We project that the supply of BBD to the U.S. will increase through 2025. Consistent with our updated projections of feedstock availability discussed in the preceding section, our projections of BBD production and imports are higher in this final rule than in the proposed rule, particularly in 2025. We project that the largest increases will come from domestic renewable diesel as new production facilities come online. We project slight decreases in the volume of biodiesel used in the U.S. as new renewable diesel producers are able to out-compete some existing biodiesel producers for limited feedstocks. One significant factor that is likely to negatively impact biodiesel production relative to renewable diesel production is that opportunities for renewable diesel expansion in California are not constrained by blending limits. Renewable diesel can therefore continue to benefit from both LCFS credits and the RFS RIN incentives. In contrast, continued biodiesel expansion in California is expected to be more limited due to requirements for the use of additives in higher level biodiesel blends. Consequently, for biodiesel to continue to expand, it must do so primarily outside of California and without the added financial incentive of the LCFS credits. This provides a significant advantage to renewable diesel in the competition for access to new feedstocks, particularly feedstocks with low carbon intensity (CI) scores in California's LCFS program and Oregon and Washington's Clean Fuels programs. While we project most of the biodiesel and renewable diesel supplied to the U.S. will be produced domestically, we project that imports of both biodiesel and renewable diesel will continue to contribute to the supply of these fuels through 2025. We note that in the first quarter of 2023 imports of biodiesel and renewable diesel, and the feedstocks used to produce these fuels in the U.S., increased substantially on a year-over-year basis, seemingly in response to the proposed volume requirements for 2023–2025. See RIA Chapter 6.2 for more information on the projected supply of biodiesel and renewable diesel to the U.S. in 2023–2025. We take this data into consideration both in our assessment of the candidate volumes of non-cellulosic advanced biofuel (discussed in Section III.C.2) and the final volumes of advanced and total renewable fuel (discussed in Section VI).

3. Other Advanced Biofuel

In addition to BBD, other renewable fuels that qualify as advanced biofuel have been consumed in the U.S. in the past and would be expected to contribute to compliance with applicable volume requirements in the years after 2022. These other advanced biofuels include imported sugarcane ethanol, domestically produced advanced ethanol, biogas that is purified and compressed to be used in CNG or LNG vehicles, heating oil, naphtha, and renewable diesel that does not qualify as BBD.[96] However, these biofuels have been consumed in much smaller quantities than biodiesel and renewable diesel in the past, and/or have been highly variable.

We did not receive a significant number of comments suggesting alternative projections of other advanced biofuel volumes. The comments we did receive generally suggested higher volumes might be appropriate due to expectations of increased production of SAF[97] (which is covered in Section III.B.2) and CNG/LNG produced from food waste or other non-cellulosic feedstocks. For this final rule we used the same general projection methodology as in the proposed rule, but we included data from 2022 that was not available at the time of the proposed rule. The inclusion of this additional data resulted in slightly higher volumes of other advanced biofuels relative to the proposed rule.

In order to estimate the volumes of these other advanced biofuels that may be available in 2023–2025, we used the same general methodology as in the proposed rule. This methodology was originally presented in the annual rulemaking establishing the applicable standards for 2020–2022.[98] This methodology addresses the historical variability in these categories of advanced biofuel while recognizing that consumption in more recent years is likely to provide a better basis for making future projections than consumption in earlier years. Specifically, we applied a weighting scheme to historical volumes wherein the weighting was higher for more recent years and lower for earlier years. The result of this approach is shown in the table below. Details of the derivation of these estimates can be found in RIA Chapter 5.4.

TABLE III.B.3–1—ESTIMATE OF FUTURE CONSUMPTION OF OTHER ADVANCED BIOFUEL

| Fuel | Volume (million RINs) |
|---|---|
| Imported sugarcane ethanol | 95 |
| Domestic ethanol | 27 |
| CNG/LNG | 6 |
| Heating oil | 3 |

*to secure renewable feedstock,* Reuters, Sept. 2, 2021.

[96] Renewable diesel produced through coprocessing vegetable oils or animal fats with petroleum cannot be categorized as BBD but remains advanced biofuel. See 40 CFR 80.1426(f)(1).

[97] While the existing pathways for SAF qualify as BBD, rather than advanced biofuel, some commenters stated that increasing production of SAF would result in additional volumes of other advanced biofuel.

[98] 87 FR 39600 (July 1, 2022).

TABLE III.B.3–1—ESTIMATE OF FUTURE CONSUMPTION OF OTHER ADVANCED BIOFUEL—Continued

| Fuel | Volume (million RINs) |
|---|---|
| Naphtha | 55 |
| Renewable diesel | 104 |
| Total | 290 |

As the available data does not permit us to identify an upward or downward trend in the historical consumption of these other advanced biofuels, we have used the volumes in Table III.B.3–1 for all years covered in this final rule (*i.e.,* 2023–2025).

4. Conventional Renewable Fuel

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

- Is demonstrated to achieve a minimum 20 percent reduction in GHGs in comparison to the gasoline or diesel which it displaces; or
- Is exempt (''grandfathered'') from the 20 percent minimum GHG reduction requirement due to having been produced in a facility or facility expansion that commenced construction on or before December 19, 2007, as described in 40 CFR 80.1403.[99]

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

To estimate candidate volumes of conventional renewable fuel for 2023–2025, we focused primarily on projecting volumes of corn ethanol consumption, which in turn is driven by total ethanol consumption. For this final rule we have updated our projections of total ethanol consumption and corn ethanol consumption based on the comments we received and additional data that was not available for the proposed rule. We also investigated potential volumes of non-advanced biodiesel and renewable diesel.

[99] CAA section 211(o)(2)(A)(i).

a. Corn Ethanol

Ethanol made from corn starch has dominated the renewable fuels market on a volume basis in the past and is expected to continue to do so for the time period addressed by this rulemaking.[100] Corn starch ethanol is prohibited by statute from being an advanced biofuel regardless of its GHG performance in comparison to gasoline.[101]

Total domestic corn ethanol production capacity increased dramatically between 2005 and 2010 and increased at a slower rate thereafter. In 2022, production capacity had reached 17.7 billion gallons.[102] [103] Available production capacity was significantly underused in 2020 and to some degree in 2021 because the COVID–19 pandemic depressed gasoline demand in comparison to previous years and thus ethanol demand in the form of E10 (gasoline containing 10% denatured ethanol). Actual production of ethanol in the U.S. reached 15.4 billion gallons in 2022, compared to 16.1 billion gallons in 2018.[104]

The expected annual rate of future commercial production of corn ethanol will continue to be driven primarily by gasoline demand in the 2023–2025 timeframe as most gasoline is expected to continue to contain 10 percent ethanol. Commercial production of corn ethanol is also a function of exports of ethanol and the demand for E0, E15, and E85. We have incorporated projected growth in opportunities for sales of E15 and E85 into our assessment. There is an excess of production capacity of ethanol and corn feedstock in comparison to the ethanol volumes that we estimate will be consumed in the near future given constraints on consumption as described in Section III.B.5. Thus, consistent with the proposed rule, it does not appear that production capacity will be a limiting factor in 2023–2025 for meeting the candidate volumes.

[100] Conventional ethanol from feedstocks other than corn starch have been produced in the past, but at significantly lower volumes. Production of ethanol from grain sorghum reached an historical high of 125 million gallons in 2019, representing just less than 1 percent of all conventional ethanol in that year; grain sorghum ethanol in 2022 was only 77 million gallons. Waste industrial ethanol and ethanol made from non-cellulosic portions of separated food waste have been produced more sporadically and at even lower volumes. These other sources do not materially affect our assessment of volumes of conventional ethanol that can be produced.

[101] CAA section 211(o)(1)(B)(i).

[102] ''2022 Ethanol Industry Outlook—RFA,'' available in the docket.

[103] ''Ethanol production capacity—EIA August 2022,'' available in the docket.

[104] ''EIA Monthly Energy Review, April 2023,'' available in the docket.

b. Biodiesel and Renewable Diesel

Other than corn ethanol, the only other conventional renewable fuels that have been used at significant levels in the U.S. have been biodiesel and renewable diesel. The vast majority of those volumes were imported, and all of it was grandfathered under 40 CFR 80.1403 and thus was not required to meet the 20 percent GHG reduction requirement. While conventional biodiesel and renewable diesel could be used in 2023–2025, as in the proposed rule we are not projecting any volumes of these fuels will be used in these years.[105]

Actual global production of palm oil biodiesel and renewable diesel was about 4.5 billion gallons in 2021.[106] The U.S. could be an attractive market for this foreign-produced conventional biodiesel and renewable diesel if domestic demand for conventional renewable fuel exceeded domestic supply, *i.e.,* the amount of ethanol that could be consumed combined with domestic production of conventional biodiesel and renewable diesel. While there is no RIN-generating pathway for biodiesel or renewable diesel produced from palm oil in the RFS program, fuels produced at grandfathered facilities from any feedstock meeting the definition of ''renewable biomass'' may be eligible to generate conventional renewable fuel RINs. Total foreign production capacity at grandfathered biodiesel and renewable diesel production facilities is approximately 1 billion gallons, suggesting that significant volumes of grandfathered biodiesel and renewable diesel could be imported under favorable market conditions.

Historical U.S. imports of conventional biodiesel and renewable diesel have been only a small fraction of global production in the past. Conventional biodiesel imports rose between 2012 and 2016, reaching a high of 113 million gallons.[107] After 2016,

[105] Data from EMTS shows some generation of D6 RINs for biodiesel and renewable diesel in recent years, however these RINs were retired using the retirement code ''renewable fuel used or designated to be used in any application that is not transportation fuel, heating oil, or jet fuel.'' These RINs therefore do not represent qualifying fuel under the RFS program.

[106] Total worldwide production of biodiesel and renewable diesel was 55 billion liters in 2021, of which 31 percent was from palm oil. See OECD–FAO Agricultural Outlook 2022–2031, p.236, available at *https://www.oecd.org/development/oecd-fao-agricultural-outlook-19991142.htm.*

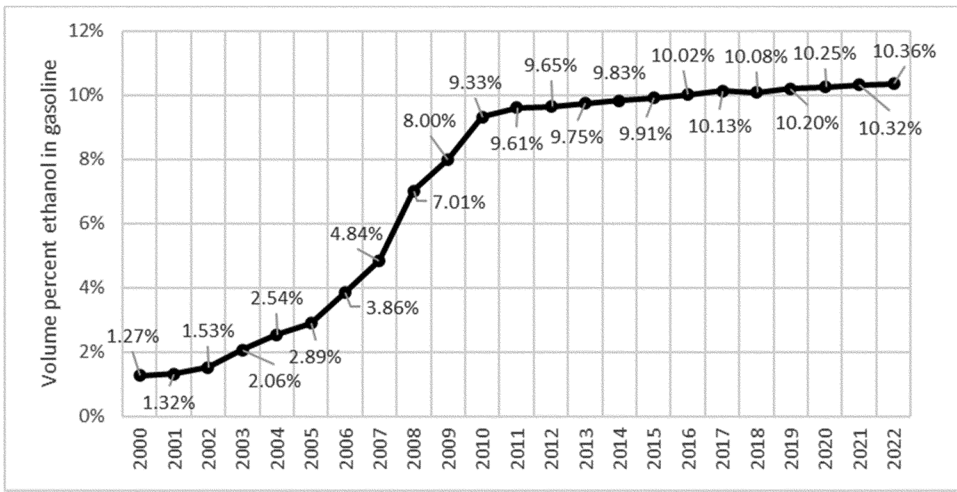
[107] ''RIN supply as of 3–7–23,'' available in the docket.

however, there have been no imports of conventional biodiesel. Small refinery exemptions granted from 2016–2018 decreased demand for renewable fuel in the U.S. and likely had an impact on conventional biodiesel and renewable diesel imports. Imports of conventional renewable diesel have been similarly low, reaching a high of 87 million gallons in 2015 with no conventional renewable diesel imported since 2017.[108] The highest imported volume of total conventional biodiesel and renewable diesel occurred in 2016 with 160 million gallons (258 million RINs).

5. Ethanol Consumption

Ethanol consumption in the U.S. is dominated by E10, with higher ethanol blends such as E15 and E85 being used in much smaller quantities. The total volume of ethanol that can be consumed, including that produced from corn, cellulosic biomass, the non-cellulosic portions of separated food waste, and sugarcane, is a function of these three ethanol blends and demand for E0. The use of these different gasoline blends is reflected in the poolwide ethanol concentration which increased dramatically from 2003 through 2010 and thereafter increased at a considerably slower rate.[109]

**Figure III.B.5-1: Poolwide Ethanol Concentration Over Time**




**Source**: Derived from ethanol and gasoline consumption in EIA's Monthly Energy Review

As the average ethanol concentration approached and then exceeded 10 percent, the gasoline pool became saturated with E10, with a small, likely stable volume of E0 and small but increasing volumes of E15 and E85. The average ethanol concentration can exceed 10 percent only insofar as the ethanol in E15 and E85 exceeds the ethanol content of E10 and more than offsets the volume of E0.

We used the same general methodology to project total ethanol consumption in this final rule as in the proposed rule, but we updated the projections of poolwide ethanol concentration and total gasoline consumption using more recent data. This methodology is different than the methodology used in previous RFS rules, which generally looked to EIA projections of ethanol concentration in the gasoline pool. We have used this new methodology to better account for the projected increase in retail stations selling higher level blends such as E15 and E85.[110]

In order to project total ethanol consumption for 2023–2025, we correlated the poolwide average ethanol concentration shown in the figure above with the number of retail service stations offering E15 and E85. Projections of the number of stations offering these blends in the future then provided a basis for a projection of the average ethanol concentration, and thus of total ethanol volumes consumed. In this final rule we updated both the correlations between E15 and E85 stations and poolwide ethanol consumption and our projections of the number of E15 and E85 stations for 2023–2025. The results are shown in Table III.B.5–1. While the projected ethanol concentration in 2023–2025 are similar to the projected concentrations from the proposed rule, projected ethanol consumption for 2023–2025 is significantly lower due to lower projected gasoline demand in these years in EIA's most recent AEO. Details of these calculations can be found in the RIA.

[108] ''RIN supply as of 3–7–23,'' available in the docket.

[109] As discussed in Section VII.B, the gasoline+diesel estimates used to calculate the percentage standards have historically been lower than the gasoline+diesel volumes used by obligated parties to determine their Renewable Volume Obligations (RVO). Relatedly, the historical ethanol concentration values shown in Figure III are likely to be higher than actual values due to some underestimates of total gasoline demand.

[110] See RIA Chapter 6.5.1 for more information on our projections of ethanol concentration in the gasoline pool.

TABLE III.B.5–1—PROJECTED ETHANOL CONSUMPTION

| Year | Projected ethanol concentration (%) | Projected ethanol consumption (million gallons) |
|---|---|---|
| 2023 | 10.41 | 13,974 |
| 2024 | 10.46 | 14,128 |
| 2025 | 10.51 | 13,978 |

### *C. Candidate Volumes for 2023–2025*

Based on our analysis of supply-related factors as described in Section III.B above, we developed candidate volumes for 2023–2025 which we then analyzed under the other economic and environmental factors required by the statute. This section describes the candidate volumes, while Section IV summarizes the results of the additional analyses we performed. Relative to the candidate volumes in the proposed rule, the candidate volumes for cellulosic biofuel, BBD, and other advanced biofuels in this final rule are all higher for all three years (after accounting for the fact that we are not finalizing the proposed eRIN provisions in this rule). The candidate volumes for conventional biofuel in this final rule are lower than the volumes from the proposed rule.

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

#### 1. Cellulosic Biofuel

In determining the candidate volumes for cellulosic biofuel, we started by considering the statutory volume targets for 2010–2022. The statutory volumes for cellulosic biofuel increased rapidly, from 100 million gallons in 2010 to 16 billion gallons in 2022 with the largest increases in the later years. While notable on its own, it is even more notable in comparison to the implied statutory volumes for the other renewable fuel volumes. Statutory BBD volumes did not increase after 2012, implied conventional renewable fuel volumes did not increase after 2015, and non-cellulosic advanced biofuel volume increases tapered off in recent years with a final increment in 2022. Thus, the clear focus of the statute by 2022 was on growth in cellulosic biofuel volumes, which have the greatest greenhouse gas reduction threshold requirement in the statute.[111] The statutory cellulosic waiver provision,[112] while acknowledging that the statutory cellulosic biofuel volumes may not be met, nevertheless effectively expresses support for the cellulosic biofuel industry in directing EPA to establish the cellulosic biofuel volume at the projected volume available in years when the projected volume of cellulosic biofuel production was less than the statutory volume. This increasing emphasis in the statute on cellulosic biofuel over time is likely due to expectations that cellulosic biofuel has significant potential to reduce GHG emissions (cellulosic biofuels are required to reduce GHG emissions by 60 percent relative to the gasoline or diesel fuel they displace), that cellulosic biofuel feedstocks could be produced or collected with relatively few negative environmental impacts, that the feedstocks would be comparable or cheaper in cost relative to other fuel feedstocks, allowing for lower cost biofuels to be produced than those produced from feedstocks without other primary uses such as food, and that the technological breakthroughs needed to convert cellulosic feedstocks into biofuel were likely imminent.

The candidate volumes discussed in this section represent the volume of qualifying cellulosic biofuel we project will be produced or imported into the U.S. in 2023–2025, after taking into consideration the incentives provided by the RFS program and other available state and federal incentives. The candidate volumes for 2023–2025 are shown in Table III.C.1–1. Because the technical, economic, and regulatory challenges related to cellulosic biofuel production vary significantly between the various types of cellulosic biofuel, we have shown the candidate volumes for liquid cellulosic biofuel and CNG/LNG derived from biogas separately. Relative to the proposed rule the candidate volumes of CNG/LNG derived from biogas are higher in all three years due to the use of a higher growth rate to project these volumes. Similarly, volumes of ethanol from CKF are higher in all three years as we are now projecting additional facilities will register as cellulosic biofuel producers using this pathway. Despite the increase in RNG use as CNG/LNG and the addition of ethanol from CKF, total cellulosic biofuel volumes for 2024 and 2025 are significantly lower in this final rule relative to the proposal because we are not finalizing the eRIN provisions in this rule.

[111] CAA section 211(o)(1)(E). *Cf.* CAA section 211(o)(1)(B)(i), (D), (2)(A)(i). See also definition of ''cellulosic biofuel'' at 40 CFR part 80, section 1401.

[112] CAA section 211(o)(7)(D).

TABLE III.C.1–1—CELLULOSIC BIOFUEL CANDIDATE VOLUMES

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| RNG use as CNG/LNG | 831 | 1,039 | 1,299 |
| Ethanol from CKF | 7 | 51 | 77 |
| Total Cellulosic Biofuel | 838 | 1,090 | 1,376 |

2. Non-Cellulosic Advanced Biofuel

Although there are no volume targets in the statute for years after 2022, the statutory volume targets for prior years represent a useful point of reference in the consideration of volumes that may be appropriate for 2023–2025. For non-cellulosic advanced biofuel, the implied statutory requirement increased in every year between 2009 and 2019.[113] It remained at 4.5 billion gallons for three years before finally rising to 5.0 billion gallons in 2022. The candidate volumes for non-cellulosic advanced biofuel in the final rule are higher than the candidate volumes from the proposed rule for 2023–2025. The increases are primarily the result of higher projections of feedstock availability allowing for greater renewable diesel production relative to the proposed rule.

For years after 2022, we anticipate that a key factor in the growth in the production of advanced biodiesel and renewable diesel (the two non-cellulosic advanced biofuels projected to be available in the greatest quantities through 2025) will be the availability of feedstocks as discussed in III.B.2.c. above. We expect small increases in the supply of FOG and distillers corn oil, but we project that the largest increases in feedstock availability in the U.S. will come from increased production of soybean oil. This expectation is largely in line with data and input provided by commenters on the December 2022 proposed rule. Significant investments have been made in recent years that would result in higher domestic soybean crushing capacity and thus soybean oil production, particularly in 2024 and 2025 (see additional discussion of the availability of biodiesel and renewable feedstocks in RIA Chapter 6.2.3). Similar investments have also been made to increase the production of canola oil in Canada, much of which could be supplied to U.S. markets for biofuel production. While advanced biofuels have the potential for significant GHG reductions, if pushing volume requirements beyond the supply of low-GHG feedstocks results in an increased use of higher-GHG feedstocks in non-biofuel markets as low-GHG feedstocks are increasingly used for biofuel production, then it would prove counterproductive.

Based on these considerations, we believe that increases in the volume of non-cellulosic advanced biofuel in the 2023–2025 timeframe should primarily be based on projected increases in the availability of feedstocks from the U.S. and Canada. One potential methodology for projecting the available supply of BBD in 2023–2025 is to base the projected supply for these years solely on the quantity of these fuels supplied in 2022 and the projected increases in feedstock availability in the U.S. and Canada (see RIA Chapter 6.2 for additional detail on our projections of biodiesel and renewable diesel supply for 2023–2025). However, RIN generation data from the first three months of 2023 indicates that the market is supplying greater volumes of non-cellulosic advanced biofuel than we would project based only on the quantity of these fuels used in 2022 plus the projected growth in feedstock production in the U.S. and Canada. The market appears to be responding to the proposed RFS volume requirements for 2023 by drawing upon imports and other sources of feedstock.

The candidate volumes for non-cellulosic advanced biofuel for 2023–2025 attempt to balance the longer-term desire to maximize the benefits (and minimize the potential negative impacts) of non-cellulosic advanced biofuel production by aligning growth in these fuels with the projected growth in feedstock production in North America and the observed data on the quantities of these fuels that have been supplied to the U.S. in the first quarter of 2023 (see Section VI for further discussion of this topic). The candidate volume for 2023 is equal to the quantity of non-cellulosic advanced biofuels to meet the proposed RFS volumes for 2023 (including the projected shortfall in conventional renewable fuel), consistent with the recent market data that indicates that the market is on track to supply this quantity of non-cellulosic advanced biofuel. The candidate volume for 2024 was determined in the same way, but we note that we project that a greater proportion of the increase over the quantity of these fuels supplied in 2022 is project to be supplied with feedstocks from North America (rather than other foreign countries) as soybean and canola crush capacity increases. Finally, the candidate volume for 2025 is primarily based on the projected increase in feedstocks from North America projected to be available to biofuel producers. These candidate volumes are shown in Table III.C.2–1, and the basis for these volumes are discussed in more detail in RIA Chapter 6.

TABLE III.C.2–1—TOTAL NON-CELLULOSIC ADVANCED BIOFUEL CANDIDATE VOLUMES

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Advanced biodiesel | 2,565 | 2,500 | 2,436 |
| Advanced renewable diesel [a] | 3,650 | 3,705 | 4,445 |
| Other advanced biofuel | 290 | 290 | 290 |

[113] See CAA section 211(o)(2)(B).

TABLE III.C.2–1—TOTAL NON-CELLULOSIC ADVANCED BIOFUEL CANDIDATE VOLUMES—Continued

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Total | 6,505 | 6,495 | 7,171 |

[a] Represents only renewable diesel and jet fuel with a D code of 4. Advanced renewable diesel with a D code of 5 is included in "Other advanced biofuel." See also Table III.B.3–1.

3. Conventional Renewable Fuel

Consistent with the statute, EPA increased the implied conventional renewable fuel volumes every year between 2009 and 2015, after which it remained at 15 billion gallons through 2022.[114] [115] However, since 2017 these standards were set with the expectation that corn ethanol and other conventional biofuel volumes would not be sufficient to meet the standards, and instead advanced biofuel volumes would be required to make up for the shortfall. This is consistent with our observations of the market, in which the total supply of conventional renewable reached a maximum of approximately 14.5 billion gallons in 2016–2018. The candidate volume for conventional renewable in this final rule are based primarily on supply related factors rather than the implied volume requirements for conventional renewable fuel in previous RFS rules.

The amount of conventional ethanol that could be consumed between 2023 and 2025 can be estimated from the total ethanol consumption projections from Table III.B.5–1 and our projections for other forms of ethanol as discussed earlier in this section. Relative to the proposed rule both total ethanol consumption and corn ethanol consumption are significantly lower in all years, primarily due to lower projections of gasoline consumption in EIA's most recent AEO. We do not currently project that non-ethanol conventional renewable fuels will be supplied to the U.S. in 2023–2025. Therefore, our candidate volumes for conventional renewable fuel are equal to our projections of conventional ethanol consumption for 2023–2025.

TABLE III.C.3–1—PROJECTIONS OF ETHANOL CONSUMPTION

[Million gallons]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Ethanol in all blends | 13,974 | 14,128 | 13,978 |
| Cellulosic ethanol | 7 | 51 | 77 |
| Imported sugarcane ethanol | 95 | 95 | 95 |
| Domestic advanced ethanol | 27 | 27 | 27 |
| Conventional ethanol | 13,845 | 13,955 | 13,779 |

Since conventional ethanol consumption would be about 13.8–14.0 billion gallons, there would need to be about 1.0–1.2 billion ethanol-equivalent gallons of non-ethanol renewable fuel in order for the implied conventional renewable fuel volumes of 15.0 billion gallons to be met.

4. Treatment of Carryover RINs

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

CAA section 211(o)(5) requires that EPA establish a credit program as part of its RFS regulations, and that the credits be valid for obligated parties to show compliance for 12 months as of the date of generation. EPA implemented this requirement through the use of RINs, which are generated for the production of qualifying renewable fuels. Obligated parties can comply by blending renewable fuels themselves, or by purchasing the RINs that represent the renewable fuels from other parties that perform the blending. RINs can be used to demonstrate compliance for the year in which they are generated or the subsequent compliance year. Obligated parties can obtain more RINs than they need in a given compliance year, allowing them to "carry over" these excess RINs for use in the subsequent compliance year, although the RFS regulations limit the use of these carryover RINs to 20 percent of the obligated party's renewable volume obligation (RVO).[116] For the collective supply of carryover RINs to be preserved from one year to the next, individual carryover RINs are used for compliance before they expire and are essentially replaced with newer vintage RINs that are then held for use in the next year. For example, vintage 2022 carryover RINs must be used for compliance with 2023 compliance year obligations, or they will expire.

[114] See CAA section 211(o)(2)(B).

[115] While the 2020 implied volume requirement was originally set at 15 billion gallons (85 FR 7016, February 6, 2020), we reduced it to the volume actually consumed due to the significant impacts of the COVID–19 pandemic on demand for renewable fuel and our change to the treatment of exemptions for small refineries (87 FR 39600, July 1, 2022). For 2021, as EPA did not establish applicable standards with sufficient time to influence market behavior, we set the implied volume requirement for conventional renewable fuel at the level actually consumed. In 2016 EPA reduced the implied conventional renewable fuel volume to 14.5 billion gallons under our general waiver authority; this action was subsequently invalidated by the D.C. Circuit Court of Appeals in *ACE.* In this rule we are completing our response to the *ACE* remand by establishing a supplemental volume requirement of 250 million gallons of renewable fuel for 2023. This "supplemental standard" follows the implementation of a 250-million-gallon supplement for 2022 in a previous action. These two supplemental actions effectuates the Congressionally determined renewable fuel volume for 2016, modified only by the proper exercise of EPA's waiver authorities, as upheld by the court in *ACE,* as discussed in Section V.

[116] 40 CFR 80.1427(a)(5).

However, vintage 2023 RINs can then be saved for use toward 2024 compliance.

As noted in past RFS annual rules, carryover RINs are a foundational element of the design and implementation of the RFS program.[117] Carryover RINs are important in providing a liquid and well-functioning RIN market upon which success of the entire program depends, and in providing obligated parties compliance flexibility in the face of substantial uncertainties in the transportation fuel marketplace.[118] Carryover RINs enable parties ''long'' on RINs to trade them to those ''short'' on RINs, instead of forcing all obligated parties to comply through physical blending. Carryover RINs also provide flexibility and reduce spikes in compliance costs in the face of a variety of unforeseeable circumstances—including weather-related damage to renewable fuel feedstocks and other circumstances potentially affecting the production and distribution of renewable fuel—that could limit the availability of RINs.

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

Carryover RINs have also provided flexibility when EPA considered the need to use its waiver authorities to lower previously established volumes. For example, in the context of the 2013 RFS rulemaking we noted that an abundance of carryover RINs available in that year, together with possible increases in renewable fuel production and import, justified maintaining the advanced and total renewable fuel volume requirements for that year at the levels specified in the statute.[119]

a. Projected Number of Available Carryover RINs

The projected number of available carryover RINs after compliance with the 2021 standards (*i.e.,* the number of carryover RINs available for compliance with the 2022 standards) are summarized in Table III.C.4.a–1.[120]

TABLE III.C.4.a–1—PROJECTED 2021 CARRYOVER RINS

[Million RINs]

| RFS standard | RIN type | Absolute 2021 carryover RINs [a] | Effective 2021 carryover RINs [b] |
|---|---|---|---|
| Cellulosic Biofuel | D3+D7 | 25 | 0 |
| Non-Cellulosic Advanced Biofuel [c] | D4+D5 | 61 | 0 |
| Conventional Renewable Fuel [d] | D6 | 1,047 | 494 |

[a] Represents the absolute number of 2021 carryover RINs that are available for compliance with the 2022 standards and does not account for deficits carried forward from 2021 into 2022.

[b] Represents the effective number of 2021 carryover RINs that are available for compliance with the 2022 standards after accounting for deficits carried forward from 2021 into 2022. Standards for which deficits exceed the number of available carryover RINs are represented as zero.

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

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

Assuming that the market exactly meets the 2022, 2023, and 2024 standards with new RIN generation, these are also the number of carryover RINs that would be available for 2023, 2024, and 2025 (including the 2023 supplemental standard). However, the standards we established for 2022 (including the 2022 supplemental standard) were significantly higher than the volume of renewable fuel used in previous years, and the candidate volumes would represent increases for 2023–2025. While we project that the volume requirements in 2022 and the candidate volumes for 2023–2025 could be achieved without the use of carryover RINs, there is nevertheless some uncertainty about how the market would choose to meet the applicable standards.[121] The result is that there remains some uncertainty surrounding the ultimate number of carryover RINs that will be available for compliance with the 2023, 2024, and 2025 standards (including the 2023 supplemental standard). In particular, as discussed in RIA Chapter 1.11, the percentage standards established for 2020 and 2021 were more stringent than EPA anticipated (*i.e.,* the volume of gasoline and diesel reported by obligated parties for these compliance years was higher than volume used by EPA to set the standards), resulting in an unexpected drawdown of the number of available

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

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

[119] 79 FR 49793–95 (August 15, 2013).

[120] The calculations performed to project the number of available carryover RINs can be found in RIA Chapter 1.10.

[121] Per 40 CFR 80.1451(f)(1)(i)(B)(*4*), the compliance deadline for the 2022 standards will be the first quarterly reporting deadline after the effective date of this action. We expect this deadline is likely to be December 1, 2023.

carryover RINs as a result of compliance with the 2020 and 2021 standards. In addition, a number of small refineries have elected to defer compliance with their 2020 obligations by opting-in to the alternative RIN retirement schedule for small refineries.[122] This flexibility allows small refineries to use any valid RIN (including 2023 and 2024) to comply with their 2020 RVOs as part of a quarterly RIN retirement schedule and effectively reduces the number of 2021–2024 carryover RINs available to comply with the 2022–2025 standards. Furthermore, we note that there have been enforcement actions in past years that have resulted in the retirement of carryover RINs to make up for the generation and use of invalid RINs and/or the failure to retire RINs for exported renewable fuel. To the extent that there are enforcement actions in the future, they could have similar results and require that obligated parties or renewable fuel exporters settle past enforcement-related obligations in addition to complying with the annual standards. In light of these uncertainties, the number of available carryover RINs could be larger or smaller than the number projected in Table III.C.4.a–1.

We acknowledge that the effective number of cellulosic and non-cellulosic advanced biofuel carryover RINs is zero, and that the effective number of conventional renewable fuel carryover RINs is significantly lower than it has been in recent years. We have recently taken actions to preserve the number of carryover RINs, and to ensure the continued functioning of the RIN market, and continue to believe that carryover RINs serve a vital programmatic function.[123] We have monitored RIN prices as a proxy for RIN market functioning, and given current RIN prices, we continue to believe the RIN market is liquid and fungible. Moreover, we note that the demand for RINs has been somewhat reduced and dispersed across a broad range of RIN vintages as a result of several actions related to small refineries: (1) The use of the alternative RIN retirement schedule in 40 CFR 80.1444, which gives small refineries additional time and opens a broader range of RIN vintages to acquire and retire the RINs needed to demonstrate compliance for the 2020 compliance year; and (2) The requests by several small refineries, granted by three different U.S. Circuit Courts of Appeals, to stay their RFS compliance obligations as part of the pending litigation challenging the EPA's April 2022 [124] and June 2022 [125] SRE Denial Actions.[126] We will continue to monitor RIN prices and the market, and retain our ability to modify future volumes through the use of our waiver authorities as discussed in Section II.F.

Even though carryover RIN levels are low, we believe that the standards we are finalizing in this action, including the supplemental standard, can be met through additional production of renewable fuel in the market. Additionally, should the market fall short of the volumes we are finalizing, obligated parties will continue to be able to carry forward a RIN deficit from one year into the next, although they may not carry forward a deficit for consecutive years. Conversely, should the market over-comply with the standards we are finalizing, the number of available carryover RINs could again grow.

b. Treatment of Carryover RINs for 2023–2025

We evaluated the volume of carryover RINs projected to be available and considered whether we should include any portion of them in the determination of the candidate volumes that we analyzed or the volume requirements that we finalized for 2023–2025 (including the 2023 supplemental volume). Doing so would be equivalent to intentionally drawing down the number of available carryover RINs in setting those volume requirements. We do not believe that this would be appropriate. In reaching this determination, we considered the functions of carryover RINs, the projected number available, the uncertainties associated with this projection, the potential impact of carryover RINs on the production and use of renewable fuel, the ability and need for obligated parties to draw on carryover RINs to comply with their obligations (both on an individual basis and on a market-wide basis), and the impacts of drawing down the number of available carryover RINs on obligated parties and the fuels market more broadly. As previously described, carryover RINs provide important and necessary programmatic functions—including as a cost spike buffer—that will both facilitate individual compliance and provide for smooth overall functioning of the program. We believe that a balanced consideration of the possible role of carryover RINs in achieving the volume requirements, versus maintaining an adequate number of carryover RINs for important programmatic functions, is appropriate when EPA exercises its discretion under its statutory authorities.

Furthermore, as discussed in the previous section and in RIA Chapter 1.10, the number of available carryover RINs has been significantly and unexpectedly drawn down as a result of 2020 and 2021 compliance, including effectively depleting the number of available cellulosic and non-cellulosic advanced carryover RINs. Moreover, as noted earlier, the advanced biofuel and total renewable fuel standards established for 2022 are significantly higher than the volume of renewable fuel used in previous years. As we explained in the 2020–2022 final rule, while we believed that the market could make sufficient renewable fuel available to meet the 2022 standards, there may be some challenges.[127] In addition, in this action we are for the first time prospectively establishing volume requirements for multiple years. This inherently adds uncertainty and makes it more challenging to project with accuracy the number of carryover RINs that will actually be available for each of these years. Given these factors, and the uneven holding of carryover RINs among obligated parties, we believe that further increasing the volume requirements after 2022 with the intent to draw down the number of available carryover RINs could lead to significant deficit carryforwards and noncompliance by some obligated parties that own relatively few or no carryover RINs. We do not believe this would be an appropriate outcome. Therefore, consistent with the approach we have taken in recent annual rules, we are not including carryover RINs in the candidate volumes, nor setting the 2023, 2024, and 2025 volume requirements (including the 2023 supplemental standard) at levels that would intentionally draw down the number of available carryover RINs.

We are not determining that the number of carryover RINs projected in Table III.C.4.a–1 is a bright-line threshold for the number of carryover

[122] 40 CFR 80.1444.

[123] See 87 FR 39600 (July 1, 2022), See also, ''April 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries,'' EPA–420–R–22–006, April 2022; and ''June 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries,'' EPA–420–R–22–012, June 2022.

[124] ''April 2022 Denial of Petitions for RFS Small Refinery Exemption,'' EPA–420–R–22–005, April 2022 (''April 2022 SRE Denial Action'').

[125] ''June 2022 Denial of Petitions for RFS Small Refinery Exemption,'' EPA–420–R–22–011, June 2022 (''June 2022 SRE Denial Action'').

[126] See, *e.g., Hunt Refining Co.* v. *EPA,* No. 22–12535–A, Document 33 (11th Cir.), *Calumet Shreveport Refining, et al.* v. *EPA,* No. 22–60266, Documents 209–1, 304–1 (5th Cir.), *Sinclair Wyoming, et. al.* v. *EPA,* No. 22–1073, Document 1992426 (D.C. Cir.).

[127] 87 FR 39600 (July 1, 2022).

RINs that provides sufficient market liquidity and allows carryover RINs to play their important programmatic functions. As in past years, we are instead evaluating, on a case-by-case basis, the number of available carryover RINs in the context of the RFS standards and the broader transportation fuel market at this time. Based upon this holistic, case-by-case evaluation, we are concluding that it would be inappropriate to intentionally reduce the number of carryover RINs by establishing higher volumes than what we anticipate the market is capable of achieving in 2023–2025. Conversely, while a larger number of available carryover RINs may provide greater assurance of market liquidity, we do not believe it would be appropriate to set the standards at levels specifically designed to increase the number of carryover RINs available to obligated parties.

5. Summary

Based on our analysis of supply-related factors, we identified a set of candidate volumes for each of the component categories that we believe represent achievable levels of supply related factors and other relevant considerations. These volumes are summarized in Table III.C.5–1.

TABLE III.C.5–1—CANDIDATE VOLUME COMPONENTS DERIVED FROM SUPPLY-RELATED FACTORS

[Million RINs] [a]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel (D3 & D7) | 838 | 1,090 | 1,376 |
| Biomass-based diesel (D4) | 6,215 | 6,205 | 6,881 |
| Other advanced biofuel (D5) | 290 | 290 | 290 |
| Conventional renewable fuel (D6) | 13,845 | 13,955 | 13,779 |

[a] The D codes given for each component category are defined in 40 CFR 80.1425(g). D codes are used to identify the statutory categories which can be fulfilled with each component category according to 40 CFR 80.1427(a)(2).

These are the candidate volumes that we further analyzed according to the other economic and environmental factors required under the statute in CAA 211(*o*)(2)(B)(ii). Those additional analyses are described in Section IV. Details of the individual biofuel types and feedstocks that make up these candidate volumes are provided in the RIA Chapter 3. These candidate volumes represent our assessment of the volume of renewable fuels we project could be used in the U.S. based on the expected annual rate of future commercial production of renewable fuels (one of the statutory factors), potential constraints on the domestic consumption of renewable fuels, and other relevant factors. We considered these candidate volumes when conducting the analyses of the additional statutory factors, which are summarized in Section IV and discussed in greater detail in the RIA. In Section VI, we discuss the final applicable volume targets based on a consideration of all of the factors that we analyzed—both the supply-related factors that were considered in developing the candidate volumes (discussed in this section) and the additional statutory factors discussed in Section IV.

Note that the volumes shown in Table III.C.5–1 represent the total candidate volumes for each component category of renewable fuel, not the volume requirements. The volumes of non-cellulosic advanced biofuel having a D code of 4 or 5, for instance, represent volumes that could be used to satisfy the BBD volume requirement, the advanced biofuel volume requirement, and the total renewable fuel volume requirement, including that portion of the implied volume for conventional renewable fuel that cannot be met with ethanol.

*D. Baselines*

In order to estimate the impacts of the candidate volumes, we must identify an appropriate baseline. The baseline reflects the alternative collection of biofuel volumes by feedstock, production process (where appropriate), biofuel type, and use which would be anticipated to occur in the absence of applicable standards, and acts as the point of reference for assessing the impacts. To this end, we have developed a ''No RFS'' scenario that we used as the baseline for analytical purposes. Many of the same supply-related factors that we used to develop the candidate volumes were also relevant in developing the No RFS baseline.

We also considered other possible baselines that, as described in the proposal, we did not use to assess the impacts of the candidate volumes. We discuss the alternative baselines here in an effort to describe our reasoning for the public and interested stakeholders, and because we understand there are differing, informative baselines that could be used in this type of analysis. Ultimately, we concluded that the No RFS scenario is the most appropriate to use.

1. No RFS Program

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

Importantly, a ''No RFS'' baseline would not be equivalent to a market scenario wherein no biofuels were used at all. Prior to the RFS program, both biodiesel and ethanol were used in the transportation sector, whether due to state or local incentives, tax credits, or a price advantage over conventional petroleum-based gasoline and diesel. This same situation would exist in 2023–2025 in the absence of the RFS program. Federal, state, and local tax credits, incentives, and support payments will continue to be in place for these fuels, as well as state programs such as blending mandates and Low Carbon Fuel Standard (LCFS) programs. Furthermore, now that capital investments in renewable fuels have been made and markets have been oriented towards their use, there are strong incentives in place for continuing their use even if the RFS program were to disappear. As a result, it would be improper and inaccurate to attribute all use of renewable fuel in 2023–2025 to the applicable standards under the RFS program.

To inform our assessment of the volume of biofuels that would be used in the absence of the RFS program for the years 2023 through 2025, we began by analyzing the trends in the economics for biofuel blending in prior years. Assessing these trends is important because the economics for blending biofuels changes from year to year based on biofuel feedstock and petroleum product prices and other factors which affect the relative economics for blending biofuels into petroleum-based transportation fuels. A biofuel plant investor and the financiers who fund their projects will review the historical (*e.g.,* did they lose money in a previous year), current, and perceived future economics of the biofuel market when deciding whether to continue to operate their biofuel plants, and our analysis attempted to account for these factors.

The No RFS Baseline analysis for 2023–2025 compares the biofuel cost with the fossil fuel it displaces, at the point that the biofuel is blended with the fossil fuel, to assess whether the biofuel provides an economic advantage to blenders. If the biofuel is lower cost than the fossil fuel it displaces, it is assumed that the biofuel would be used absent the RFS standards (within the constraints described below). The economic analysis that we conducted to assess the volume of biofuel that would likely be produced and consumed in the absence of the RFS program mirrors the cost analysis described in Section IV.C, but there is one primary difference and a number of other differences. The primary difference is that the economic analysis relative to the No RFS baseline assesses whether the fuels industry would find it economically advantageous to blend the biofuel into the petroleum fuel in the absence of the RFS program, whereas the social cost analysis reflects the overall impacts on society at large (see Section IV.C and RIA Chapter 10 for descriptions of the social cost analysis). The primary example of a social cost not considered for the No RFS economic analysis is the fuel economy effect due to the lower energy density of the biofuel, as this cost is generally borne by consumers, not the fuels industry. Other ways that the No RFS economic analysis is different from the social cost analysis include:

- In the context of assessing production costs, we amortized the capital costs at a higher rate of return more typical for industry investment instead of the rate of return used for social costs.
- We assessed biofuel distribution costs to the point where it is blended into fossil fuel, not all the way to the point of use that is necessary for estimating the fuel economy cost.
- While we generally do not account for the fuel economy disadvantage of most biofuels for the No RFS economic analysis, the exception is E85 where the lower fuel economy of using E85 is so obvious to vehicle owners that they demand a lower price to make up for this loss of fuel economy. As a result, retailers must price E85 lower than the primary alternative E10 to account for this bias and they must consider this in their decisions to blend and sell E85. A similar situation exists with E15, although it is not clear what the factors are for E15 and this is discussed in more detail in the No RFS Baseline discussion in RIA Chapter 2.

We added these various cost components (*i.e.,* production cost, distribution cost, any blending cost, retail cost, applicable tax subsidies) together to reflect the cost of each biofuel.

We conducted a similar cost estimate for the fossil fuels being displaced since their relative cost to biofuels is used to estimate the net cost of using biofuels. Unlike for biofuels, we did not calculate production costs for the fossil fuels. Instead, we projected their production costs based solely on wholesale price projections by the Energy Information Administration in its Annual Energy Outlook (AEO).

We also considered any applicable federal or state programs, incentives, or subsidies that could reduce the apparent blending cost of the biofuel at the terminal. An important subsidy is the $1 federal tax incentives for blending biodiesel and other biofuels into diesel fuel which was extended in the IRA.[128] In the case of higher ethanol blends, the retail cost associated with the equipment and/or use of compatible materials needed to enable the sale of these newer fuels is assumed to be reduced by 50 percent due to the Federal Higher Blends Infrastructure Incentive Program (HBIIP) program administered by the United States Department of Agriculture.

In addition, there are a number of state programs that create subsidies for biodiesel and renewable diesel fuel, the largest being offered by California and Oregon through their LCFS programs. We accounted for state and local biodiesel mandates by including their mandated volume regardless of the economics. Several states offer tax credits for blending ethanol at 10 volume percent. Other states offer tax credits for E85, of which the largest is in New York. We are not aware of any state tax credits or subsidies for E15.[129] To account for the various state assumptions, it was necessary to model the cost of using these biofuels on a state-by-state basis.

For most biofuels, the economic analysis provided consistent results, indicating that they are either economical in all years or are not economical in any year. However, this was not true for biodiesel and renewable diesel, where the results varied from year to year. Such swings in the economic attractiveness of biodiesel and renewable diesel confound efforts on the part of investors to project future returns on their investments to determine whether to continue to operate their plants, or shutdown. Thus, to smooth out the swings in the economics for using biodiesel and renewable diesel and look at it the way plant operators and their investors would have in the absence of the RFS program, we made two different key assumptions. First, the economics for biodiesel and renewable diesel were modeled starting in 2009 and the trend in its use was made dependent on the relative economics in comparison to petroleum diesel over distinct four-year periods. As a result, the first 4-year modeled period was actually 2012. Second, the estimated biodiesel and renewable diesel volumes were limited in the analysis to no greater volume than what occurred under the RFS program in any year, since the existence of the RFS program would be expected to create a much greater incentive for using these biofuels than if no RFS program were in place.

An economic analysis was also conducted for cellulosic biofuels, including cellulosic ethanol, corn kernel fiber ethanol, and biogas. Since the volumes of these biofuels were much smaller, a more generalized approach was used in lieu of the detailed state-by-state analysis conducted for corn ethanol, biodiesel, and renewable diesel fuel.

The No RFS baseline for 2023–2025 is summarized in Table III.D.1–1. A more complete description of the No RFS baseline and its derivation is provided in RIA Chapter 2. The projected consumption of cellulosic biofuel and

[128] H.R. 5376—The Inflation Reduction Act of 2022

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

other advanced biofuel in this final rule is similar to the volumes for these fuel types projected in the proposed rule, with slight variations based on updated data. The projected BBD volumes for the No RFS baseline are significantly higher in all years, primarily because the significantly higher crude oil prices from the most recent AEO make BBD more cost competitive with petroleum diesel, after accounting for the available non-RFS incentives such as the federal tax credit for BBD and the incentives offered by California's LCFS program. Finally, the conventional renewable fuel volumes for the No RFS baseline are significantly lower in all years, relative to the volumes in the proposed rule, primarily due to lower projected gasoline consumption in 2023–2025 from EIA.

TABLE III.D.1–1—BIOFUEL CONSUMPTION IN 2023–2025 UNDER A NO RFS BASELINE

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel (D3 & D7) | 343 | 402 | 444 |
| Biomass-based diesel (D4) | 2,796 | 3,139 | 3,496 |
| Other advanced biofuel (D5) | 226 | 226 | 226 |
| Conventional renewable fuel (D6) | 13,185 | 13,224 | 12,992 |

Our analysis shows that corn ethanol is economical to use in 10 percent blends (E10) without the presence of the RFS program. Conversely, higher ethanol blends would generally not be economic without the RFS program, except for some small volume of E85 in the state of New York which offers a large E85 blending subsidy. Higher-level ethanol blends are not as economical as ethanol blended as E10 because the octane value of ethanol is generally not realized in these blends, and the infrastructure cost for dispensing these fuels are high (see RIA Chapter 10). Some volume of biodiesel is estimated to be blended based on state mandates in the absence of the RFS program, and some additional volume of both biodiesel and renewable diesel is estimated to be economical to use without the RFS program, primarily in California due to the LCFS incentives. The volume of CNG from biogas and imported ethanol from sugarcane are projected to be consumed in California due to the economic support provided by their LCFS.

2. Alternative Approaches to the No RFS Baseline

We also considered several other ways to identify a No RFS baseline. However, we do not believe they would be appropriate as they would be unlikely to represent the world in 2023–2025 as it would likely be in the absence of the RFS program. For instance, the RFS program went into effect in 2006 with a default percentage standard specified in the statute. As 2005 represents the most recent year for which the RFS requirements did not apply, it could be used as the baseline in assessing costs and impacts of the candidate volumes. However, a significant number of changes to other factors that significantly affect the fuels sector have occurred between 2005 and the 2023–2025 period to which this action applies, including changes in state requirements, tax subsidies, tariffs, international supply, total fuel demand, crude oil prices, feedstock prices, and fuel economy standards. All of these have influenced the economical use of renewable fuel during the intervening period, and it is infeasible to model all these interactions. As a result, using 2005 as the baseline would lead to a highly speculative assessment of costs and impacts that neglect important market and regulatory realities. Therefore, we do not believe that a 2005 baseline would be appropriate for this rulemaking.

In the 2010 RFS2 rulemaking that created the RFS2 regulatory program that was required by EISA, one of the baselines that we used was the 2007 version of EIA's AEO which provided projections of transportation fuel use, including the use of renewable fuel, out to 2030.[130] This is the most recent version of the AEO that projected fuel use in the absence of the statutory volume targets specified in the Energy Independence and Security Act of 2007; all subsequent versions of the AEO have included the current RFS program in their projections. While the 2007 version of the AEO includes projections for the timeframe of interest in this action, 2023–2025, it suffers from the same drawbacks as using fuel use in 2005 as the baseline. Namely, a significant number of other changes have occurred between 2007 when the projections were made and the 2023–2025 period to which this action applies. For the same reasons, then, we do not believe that the projections in AEO 2007 would be an appropriate baseline.

3. Previous Year Volumes

The applicable volume requirements established for one year under the RFS program do not roll over automatically to the next, nor do the volume requirements that apply in one year become the default volume requirements for the following year in the event that no volume requirements are set for that following year. Nevertheless, the volume requirements established for the previous year represent the most recent set of volume requirements that the market was required to meet, and the fuels industry as a whole can be expected to have adjusted its operations accordingly. Since the previous year's volume requirements represent the starting point for any adjustments that the market may need to make to meet the next year's volume requirements, they represent another informational baseline for comparison, and we have used previous year standards as a baseline in previous annual standard-setting rulemakings.

The 2022 volume requirements were finalized on July 1, 2022, and are shown in Table III.D.3–1.[131]

TABLE III.D.3–1—FINAL 2022 VOLUME REQUIREMENTS

| Category | Volume (billion RINs) |
|---|---|
| Cellulosic biofuel | 0.63 |
| Biomass based diesel [a] | 2.76 |
| Advanced biofuel | 5.63 |
| Total renewable fuel | 20.63 |

[a] The BBD volumes are in physical gallons (rather than RINs).

In the final rule that established these 2022 volume requirements, we discussed the fact that the preferable baseline would have been a No RFS baseline, but that it could not be developed in the time available. Therefore, we used actual data on 2020

[130] 75 FR 14670 (March 26, 2010).

[131] 87 FR 39600 (July 1, 2022).

biofuels consumption as the primary baseline in that rule.

In the Set rule proposal, we used the 2022 volume requirements as an informational case in addition to the No RFS baseline, but we did so only for costs to allow for a comparison to the analysis and results presented in recent annual rules. We continue to believe that this is appropriate in this final rule. However, we now have data on how the market responded to the applicable 2022 standards, and we believe that this data on actual market performance is a better point of reference than the 2022 volume requirements established in the July 1, 2022 final rule. Therefore, we have used actual 2022 biofuel consumption as a baseline in the estimation of costs for this final rule, in addition to the No RFS baseline. This approach is consistent with the approach we took in the rulemaking which established the volume requirements for 2020, 2021, and 2022,[132] as well as the rulemaking which established the volume requirements for 2014, 2015, and 2016.[133] In that rule, the impacts of the volume requirements for 2015 were compared to the actual volumes consumed in 2014, and the impacts of the volume requirements for 2016 were compared to the actual volumes consumed in 2015.[134]

The volumes of biofuel consumption for 2022 are shown below. More details on 2022 biofuel consumption can be found in RIA Chapter 2.

TABLE III.D.3–2—2022 BIOFUEL CONSUMPTION

| | Volume (million RINs) |
|---|---|
| Cellulosic biofuel (D3 & D7) | 667 |
| Biomass-based diesel (D4) .. | 4,956 |
| Other advanced biofuel (D5) | 318 |
| Conventional renewable fuel (D6) .................................. | 14,034 |

### *E. Volume Changes Analyzed*

In general, our analysis of the economic and environmental impacts of the candidate volumes derived and discussed above was based on the differences between our assessment of how the market would respond to those candidate volumes (summarized in Table III.C.5–1) and the No RFS baseline (summarized in Table III.D.1–1). Those differences are shown below. Details of this assessment, including a more precise breakout of those differences, can be found in RIA Chapter 2. Note that this approach is squarely focused on the differences in volumes between the No RFS baseline and the candidate volumes; our analysis does not, in other words, assess impacts from total biofuel use in the United States. As noted above, we also consider the impacts of this rule relative to a 2022 baseline for some of our analyses, such as the cost of the rule. The changes in biofuel consumption in the transportation sector relative to the 2022 baseline are shown in in Table III.E–2.

TABLE III.E–1—CHANGES IN BIOFUEL CONSUMPTION IN THE TRANSPORTATION SECTOR IN COMPARISON TO THE NO RFS BASELINE

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel (D3 & D7) | 495 | 688 | 932 |
| Biomass-Based Diesel (D4) | 3,169 | 3,066 | 3,385 |
| Other Advanced Biofuel (D5) | 64 | 64 | 64 |
| Conventional Renewable Fuel (D6) | 660 | 731 | 787 |

TABLE III.E–2—CHANGES IN BIOFUEL CONSUMPTION IN THE TRANSPORTATION SECTOR IN COMPARISON TO THE 2022 BASELINE

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel (D3 & D7) | 172 | 424 | 710 |
| Biomass-Based Diesel (D4) | 1,271 | 1,511 | 2,187 |
| Other Advanced Biofuel (D5) | −28 | −28 | −28 |
| Conventional Renewable Fuel (D6) | −189 | −79 | −255 |

The volumes shown in Table III.D.1–1 and the volume changes shown in Tables III.E–1 and 2 include the volume of renewable fuel projected to be supplied to meet the supplemental volume requirements in 2023. For purposes of analyzing the environmental and economic impacts (discussed in Section IV), we treat the 2023 supplemental volume requirement separately as discussed in RIA Chapter 3.3. We project that the supplemental volume will be met with 147 million gallons (250 million RINs) of renewable diesel produced from soybean oil. Our analyses of the statutory factors described in Section IV generally do not include the impacts of the supplemental volume requirement, except where noted.

## IV. Analysis of Candidate Volumes

As described in Section II.B, the statute specifies a number of factors that EPA must analyze in making a determination of the appropriate volume requirements to establish for years after 2022 (and for BBD, years after 2012). A full description of the analysis for all factors is provided in the RIA. In this section, we provide a summary of the analysis of a selection of factors for the candidate volumes derived from supply-related factors as described in the previous section (see Table III.C.5–1 for the candidate volume, and Table III.E–1 for the corresponding volume changes in comparison to the No RFS baseline),

[132] 87 FR 39600 (July 1, 2022).

[133] 80 FR 77420 (Dec. 14, 2015).

[134] The 2015 volumes were based on actual consumption data for January–September and a projection for October–December.

along with some implications of those analyses. In Section VI we provide a summary of our consideration of all factors in determining the volume requirements that we have determined are appropriate for 2023–2025.

*A. Climate Change*

This section begins with a description of our analysis of the climate change impacts of the candidate volumes. Following this, in Section IV.A.2, is a description of a model comparison exercise that was not conducted for the purpose of evaluating the candidate volumes, nor does it inform the volumes in this final rule.

1. Climate Change Analysis Supporting Rule

CAA section 211(o)(2)(B)(ii) states that the basis for setting applicable renewable fuel volumes after 2022 must include, among other things, ''an analysis of . . . the impact of the production and use of renewable fuels on the environment, including on . . . climate change.'' While the statute requires that EPA base its determinations, in part, on an analysis of the climate change impact of renewable fuels, it does not require a specific type of analysis. The CAA requires evaluation of lifecycle greenhouse gas (GHG) emissions as part of the RFS program,[135] and GHG emissions contribute to climate change.[136] Thus, in the proposed rule we used lifecycle GHG emissions estimates as a proxy for climate change impacts.[137] We continue to believe this approach is reasonable and appropriate for the final rule.

To support the GHG emission reduction goals of EISA, Congress required that biofuels used to meet the RFS obligations achieve certain GHG reductions based on a lifecycle analysis (LCA). To qualify as a renewable fuel under the RFS program, a fuel must be produced from approved feedstocks and have lifecycle GHG emissions that are at least 20 percent less than the baseline petroleum-based gasoline and diesel fuels. The CAA defines lifecycle emissions in section 211(o)(1)(H) to include the aggregate quantity of significant direct and indirect emissions associated with all stages of fuel production and use. Advanced biofuels and biomass-based diesel are required to have lifecycle GHG emissions that are at least 50 percent less than the baseline fuels,[138] while cellulosic biofuel is required to have lifecycle emissions at least 60 percent less than the baseline fuels.[139] Congress also allowed for facilities that existed or were under construction when the EISA was enacted to be grandfathered into the RFS program and exempt from the lifecycle GHG emission reduction requirements.[140]

In the proposed rule, we presented biofuel LCA estimates from a range of published values from the scientific/technical literature. We are using the same approach as the proposed rule, whereby we multiply the lifecycle emissions value for each individual fuel by the change in the volume of that fuel to quantify the GHG impacts. We repeat this process for each fuel (*e.g.,* corn ethanol, soybean biodiesel, landfill biogas CNG) to estimate the overall GHG impacts of the candidate volumes. We provide a high and low estimate of the potential GHG impacts of each pathway (combination of biofuel type, feedstock, and production process) based on the range of published LCA estimates from the scientific literature. We then use this range of values for considering the GHG impacts of the renewable fuel volumes that change relative to the No RFS baseline described in Section III. Specifically, 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.[141]

To develop the range of LCA values, we conducted a high-level review of relevant literature for the biofuel pathways that would be most likely to satisfy the candidate renewable fuel volumes, as well as the petroleum-based fuels they are used to replace or reduce. Based on our review, we compiled the LCA estimates in the literature for each pathway. We include estimates from peer-reviewed journal articles, authoritative governmental reports, and other credible publications, such as studies by non-governmental organizations. Given that all LCA studies and models have particular strengths and weaknesses, as well as uncertainties and limitations, our goal for this compilation of literatures estimates is to consider the ranges of published estimates, not to adjudicate which particular studies, estimates or assumptions are most appropriate. Reflecting the many approaches to LCA and associated assumptions and uncertainties, our review is intentionally broad and inclusive of a wide range of estimates based on a variety of study types and assumptions. We focused on LCA estimates for the average type of each fuel produced in the United States.[142] For example, for corn ethanol, we focused on estimates for average corn ethanol production from natural gas-fired dry mill facilities, as that is the predominant mode of corn ethanol production in the United States.[143]

We made minor changes to the LCA ranges used in the proposed rule. We reviewed the public comments and searched the literature to identify new or additional studies to add to our review. However, public commenters did not identify any additional LCA estimates that we had not already considered. Likewise, our updated search of the literature did not identify any additional estimates. The one update we made was replacing estimates from the 2021 version of the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model with estimates from the

[135] See CAA section 211(*o*)(1)(H) (empowering the Administrator to determine lifecycle greenhouse gas emissions) and CAA section 211(*o*)(2)(A)(i) (requiring the Administrator to ''ensure that transportation fuel sold or introduced into commerce in the United States . . . contains . . . renewable fuel . . . [that] achieves at least a 20 percent reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions.,'' where the 20 percent reduction threshold applies to renewable fuel ''produced from new facilities that commence construction after December 19, 2007.'')

[136] Extensive additional information on climate change is available in other EPA documents, as well as in the technical and scientific information supporting them. See 74 FR 66496 (December 15, 2009) (finding under CAA section 202(a) that elevated concentrations of six key well-mixed GHGs may reasonably be anticipated to endanger the public health and welfare of current and future generations); 81 FR 54421 (August 15, 2016) (making a similar finding under CAA section 231(a)(2)(A)).

[137] This is consistent with EPA's analysis of the same statutory factor in the 2020–2022 Rule. See ''Renewable Fuel Standard (RFS) Program: RFS Annual Rules—Regulatory Impact Analysis,'' EPA–420–R–22–008, June 2022, pp 65–96.

[138] CAA Sections 211(o)(1)(B)(i) and 211(o)(1)(D).

[139] CAA Section 211(o)(1)(E).

[140] CAA Section 211(o)(2)(A)(i).

[141] To be more precise, for the crop-based biofuel pathways we use the range of LCA estimates that include an annual stream of emissions, which are based on the modeling for the March 2010 RFS2 rule.

[142] We note that lifecycle GHG emissions are also influenced by the use of advanced technologies and improved production practices. For example, corn ethanol produced with the adoption of advanced technologies or climate smart agricultural practices can lower LCA emissions. Corn ethanol facilities produce a highly concentrated stream of $CO_2$ that lends itself to carbon capture and sequestration (CCS). CCS is being deployed at ethanol plants and has the potential to reduce emissions for corn-starch ethanol, especially if mills with CCS use renewable sources of electricity and other advanced technologies to lower their need for thermal energy. Climate smart farming practices are being gradually adopted at the feedstock production stage and can lower the GHG intensity of biofuels. For example, reducing tillage, planting cover crops between rotations, and improving nutrient use efficiency can build soil organic carbon stocks and reduce nitrous oxide emissions.

[143] 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.

2022 version. Some of the public comments recommended removing some of the studies considered in the proposed rule. We considered these comments carefully but decided not to remove any of the studies considered in the proposed rule as they meet the broad criteria for our compilation of published estimates. We discuss these comments and our reasoning in the summary and analysis of comments document that is part of this rulemaking package.

The ranges of values in our compilation vary considerably for different types of renewable fuels, particularly for crop-based biofuels. The ranges of estimates for non-crop based biofuel pathways tend to be narrower relative to the crop-based pathways (See Table IV.A–1).

TABLE IV.A–1—LIFECYCLE GHG EMISSIONS RANGES BASED ON LITERATURE REVIEW

[$gCO_2e/MJ$]

| Pathway | LCA range |
|---|---|
| Petroleum Gasoline | 84 to 98 |
| Petroleum Diesel | 84 to 94 |
| Natural Gas CNG | 73 to 81 |
| Corn Starch Ethanol | 38 to 116 |
| Soybean Oil Biodiesel | 14 to 73 |
| Soybean Oil Renewable Diesel. | 26 to 87 |
| Used Cooking Oil Biodiesel | 12 to 32 |
| Used Cooking Oil Renewable Diesel. | 12 to 37 |
| Tallow Biodiesel | 16 to 58 |
| Tallow Renewable Diesel | 14 to 81 |
| Distillers Corn Oil Biodiesel | 14 to 37 |
| Distillers Corn Oil Renewable Diesel. | 12 to 46 |
| Landfill Gas CNG | 6 to 70 |
| Manure Biogas CNG | −533 to 52 |

2. Description of Separate Model Comparison Exercise

This section describes a model comparison exercise that we conducted for the purpose of advancing our understanding of available models and science related to the GHG impacts of biofuel consumption. We requested comment on a number of issues related to the model comparison exercise, including the approach for conducting the model comparison. At the time of proposal, we were contemplating using the model comparison exercise to inform the final rule.[144] However, 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. Work to refine models to inform future rulemakings is ongoing. We want to engage with stakeholders and receive feedback on the MCE before deciding 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 this final rule, we describe it here solely for informational purposes, as readers of Section IV.A may be interested in the technical information provided through this separate exercise.

In the March 2010 RFS2 rule (75 FR 14670) and in subsequent agency actions, EPA estimated the lifecycle GHG emissions from different biofuel production pathways; that is, the emissions associated with the production and use of a biofuel, including indirect emissions, on a per-unit energy basis. Since the existing LCA methodology was developed for the March 2010 RFS2 rule, there has been more research on the lifecycle GHG emissions associated with transportation fuels. While our existing LCA estimates for the RFS program remain within the range of more recent estimates, we acknowledge that the biofuel GHG modeling framework EPA has previously relied upon is old, and that a better understanding of these newer models and data is needed. In the proposed rule, we did not propose to reopen the related aspects of the 2010 RFS2 rule or any prior EPA lifecycle greenhouse gas analyses, methodologies, or actions, as that is beyond the scope of this rulemaking. While updating our LCA methodology is beyond the scope of this rulemaking, to make this information available to the public we are including the outcome of a model comparison exercise by placing it in the docket for this rulemaking in the document titled, ''Model Comparison Exercise Technical Document.''

The model comparison exercise has three main goals: (1) Advance the science in the area of analyzing the lifecycle greenhouse gas emissions impacts from increasing use of biofuel; (2) Identify and understand differences in scope, coverage, and key assumptions in each model, and to the extent possible the impact that those differences have on the appropriateness of using a given model to evaluate the GHG impacts of biofuels; and (3) Understand how differences between models and data sources lead to varying results. As we designed and conducted the model comparison exercise, we consulted with our colleagues within the USDA and DOE.

Following the proposed rule, the National Academies of Sciences, Engineering, and Medicine (NASEM) published a report titled ''Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States.'' The conclusions and recommendations from the NASEM report support our motivations for conducting the model comparison. In particular, recommendation 4–2 from the report states, ''Current 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.'' Consistent with this and other recommendations in the NASEM report, our model comparison exercise compares results from multiple models, and we strive to transparently consider parameter, scenario and model uncertainties.

LCA plays several diverse roles in the context of the RFS program. Under Section 211(o)(2)(B)(ii)(I) of the CAA, EPA is required to analyze the climate change impacts of this rule and other RFS rules that establish the renewable fuel standards subject to the requirements of CAA section 211(o)(2)(B)(ii). 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. The model comparison exercise does not support these analytical needs at this time, but the insights on modeling and science from this exercise may inform future analytical efforts on both of these topics. Our work related to biofuel GHG modeling and lifecycle analysis will continue after this rulemaking.

For the model comparison exercise we selected five models, listed below in alphabetical order, that provide different insights into the climate change impacts of crop-based biofuel production. First, the Applied Dynamic Analysis of the Global Economy (ADAGE) model, is an economic model that includes all sectors of the economy, including agriculture, bioenergy, and transportation. Second, the Global Change Analysis Model (GCAM), simulates the world's energy, water, agriculture, land, climate and economic systems. Third, the Global Biosphere Management Model (GLOBIOM) is an economic model of the agricultural, forest and bioenergy sectors. Fourth, the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model is a lifecycle analysis model that estimates the well-to-wheels impacts of transportation technologies.

[144] See 87 FR 80582, 80611 (December 30, 2022).

Finally, the Global Trade Analysis Project (GTAP) model is a general equilibrium model of all sectors of the economy. We selected these models based on our many years of experience with biofuel GHG modeling and based on stakeholder input, including the proceedings and public comments associated with the biofuel GHG modeling workshop that we hosted on February 28–March 1, 2022 (86 FR 73756).[145]

In order to facilitate a comparison of the five models, we ran common scenarios through each of them. We defined a purely hypothetical reference case, for modeling purposes only, with U.S. biofuel consumption volumes from 2020–2050 set at their average level from 2016–2019 (*e.g.,* approximately 14.8 billion gallons of corn ethanol and 1.2 billion gallons of soybean oil biodiesel). We then simulated a corn ethanol shock scenario in which the U.S. consumes an additional one billion gallons of corn ethanol in 2030 and in each year after that through 2050, with all other U.S. biofuel volumes set at the reference scenarios levels. We also simulated a similar soy biodiesel shock scenario where the U.S. consumes an additional one billion gallons of soybean oil biodiesel in the same time frame. For the dynamic models (*i.e.,* ADAGE, GCAM, GLOBIOM), we simulated the shocks as increasing linearly from 2020 to 2030, and then held the shocks constant at their 2030 levels through 2050.

While the details of the model comparison results are discussed in the Model Comparison Exercise Technical Document, we conclude this section by summarizing some of our broad conclusions from this exercise. Supply chain LCA models, such as GREET, produce a fundamentally different analysis than economic models. Supply chain LCA models evaluate the GHG emissions emanating from a particular supply chain, whereas economic models evaluate the GHG impacts of a change in biofuel consumption. Estimates of land use change vary significantly among the models used in this study. Drivers of variation in these estimates include differences in assumptions related to trade, the substitutability of food and feed products, and land conversion, as well as structural differences in how models represent land categories. Economic modeling of the energy sector may be required to avoid overestimating the emissions reduction from fossil fuel consumption. Model trade structure and assumed flexibility influence the modeled emissions results. The degree to which other vegetable oils replace soybean oil diverted to fuel production from other markets can impact GHG emissions associated with soybean oil biodiesel. The ability to endogenously consider tradeoffs between intensification and extensification is an important capability for estimating the emissions associated with an increase in biofuel consumption. Models included in the model comparison exercise produced a wider range of LCA GHG estimates for soybean oil biodiesel than corn ethanol. The models show much greater diversity in feedstock sourcing strategies for soybean oil biodiesel than they do for corn ethanol, and this wider range of options contributes to greater variability in the GHG results. Sensitivity analysis, which considers uncertainty within a given model, can help identify which parameters influence model results. However, pinpointing the direct causes of why one estimate differs from another would require additional research.

[145] Because the biofuel GHG modeling workshop was not used in any way to inform this rulemaking, we have not included any of the documents from that event as part of the record for this rulemaking.

### *B. Energy Security*

Another factor that we are required under the statute to analyze is energy security. Changes in the required volumes of renewable fuel can affect the financial and strategic risks associated with U.S. imports of petroleum, which in turn would have a direct impact on the U.S.' national energy security.

The candidate volumes for the years 2023–2025 would represent increases in comparison to previous years and, also, increases in comparison to a No RFS baseline. Increasing the use of renewable fuels in the U.S. displaces domestic consumption of petroleum-based fuels, which results in a reduction in U.S. imports of petroleum and petroleum-based fuels. A reduction of U.S. 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 U.S. energy security.

Energy security and energy independence are distinct but related concepts. U.S. energy security is commonly defined as the continued availability of energy sources at an acceptable price.[146] The goal of U.S. energy independence is the elimination of all U.S. imports of petroleum and other foreign sources of energy, or more broadly, reducing the sensitivity of the U.S. economy to energy imports and foreign energy markets.[147] Most discussions of U.S. energy security revolve around the topic of the economic costs of U.S. dependence on oil imports.

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

The U.S.' oil consumption had been gradually increasing in recent years (2015–2019) before dropping dramatically as a result of the COVID–19 pandemic in 2020.[148] Domestic oil consumption in 2022 rebounded to pre-COVID–19 levels and is expected to modestly decline during the timeframe of this final rule, 2023–2025.[149] The U.S. has increased its production of oil, particularly ''tight'' (*i.e.,* shale) oil, over the last decade.[150] Mainly as a result of this increase, the U.S. became a net exporter of crude oil and petroleum-based products in 2020 and is now projected to be a net exporter of crude oil and petroleum-based products during the time frame of this final rule, 2023–2025.[151] [152] This is a significant reversal of the U.S.' net export position since the U.S. had been a substantial net importer of crude oil and petroleum-based products starting in the early 1950s.[153]

In the beginning of 2022, world oil prices rose fairly rapidly. For example, as of January 3rd, 2022, the West Texas Intermediate (WTI) crude oil price was roughly $76 per barrel.[154] The WTI oil price increased to roughly $124 per barrel on March 8th, 2022, a 63 percent increase.[155] High and volatile oil prices in the first half of 2022 were a result of oil supply concerns with Russia's invasion of Ukraine on February 24th, 2022 contributing to crude oil price increases.[156] Russia's invasion of Ukraine came during eight consecutive

[147] Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? *Energy Policy* 38. pp. 164–1621.

[148] U.S. Energy Information Administration. 2023. Total Energy. *Monthly Energy Review.* Table 3.1. Petroleum Overview. March.

[149] U.S. Energy Information Administration. 2023. *Annual Energy Outlook* 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

[150] *https://www.eia.gov/energyexplained/oil-and-petroleum-products/images/u.s.tight_oil_production.jpg.*

[151] *https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php.*

[152] U.S. Energy Information Administration. 2023. *Annual Energy Outlook* 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

[153] EIA *https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php.*

[154] U.S. Energy Information Administration. 2022. *Petroleum and Other Liquids: Spot Prices. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.*

[155] Id.

[156] U.S. Energy Information Administration. Today in Energy. Crude oil prices increased in the first half of 2022 and declined in the second half of 2022. January.

quarters (from the third quarter of 2020 to the second quarter of 2022) of global crude oil inventory decreases.[157] The lower inventory of crude oil stocks were the result of rising economic activity after COVID–19 pandemic restrictions were eased. Oil prices drifted downwards throughout the second half of 2022 and early 2023. As of March 13th, 2023, the WTI crude oil price was roughly $75/barrel.[158]

Geopolitical disruptions that occurred in 2022 are likely to continue to affect global trade of crude oil and petroleum products in 2023 and beyond. In response to Russia's invasion of Ukraine in late February 2022, the U.S. and many of its allies, particularly in Europe, announced various sanctions against Russia's petroleum industry.[159] For the European Union (EU), petroleum from Russia had accounted for a large share of all energy imports, but the EU banned imports of crude oil from Russia starting in December 2022 and imports of petroleum products starting in February 2023.[160] Given recent oil market trends, the U.S. set a new record for petroleum product exports in 2022, up 7% from 2021.[161] It is not clear to what extent the current oil price volatility will continue, increase, or be transitory in the 2023–2025 time period addressed by this rule.

Although the U.S. is projected to be a net exporter of crude oil and petroleum-based products over the 2023–2025 timeframe, energy security remains a concern. U.S. refineries still rely on significant imports of heavy crude oil which could be subject to supply disruptions. Also, oil exporters with a large share of global production have the ability to raise or lower the price of oil by exerting their market power through 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 petroleum-based products.

In order to understand the energy security implications of reducing U.S. oil imports, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs/impacts and energy security implications of oil use, labeled the oil import or oil security premium. ORNL's methodology estimates two distinct costs/impacts of importing petroleum into the U.S., in addition to the purchase price of petroleum itself: first, the risk of reductions in U.S. economic output and disruption to the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (*i.e.,* the macroeconomic disruption/adjustment costs); and secondly, the impacts that changes in U.S. oil imports have on overall U.S. oil demand and subsequent changes in the world oil price (*i.e.,* the ''demand'' or ''monopsony'' impacts).[162]

For this final rule, as has been the case for past EPA rulemakings under the RFS program, we consider the monopsony component estimated by the ORNL methodology to be a transfer payment, and thus exclude it from the estimated quantified benefits of the candidate volumes.[163] Thus, we only consider the macroeconomic disruption/adjustment cost component of oil import premiums (*i.e.,* labeled macroeconomic oil security premiums below), estimated using ORNL's methodology.

For this final rule, EPA and ORNL have worked together to revise the oil import premiums based upon recent energy security literature and the most recently available oil price projections and energy market and economic trends from EIA's 2023 Annual Energy Outlook.[164] We do not consider military cost impacts from reduced oil use from the candidate volumes due to methodological issues in quantifying these impacts. A discussion of the difficulties in quantifying military cost impacts is in RIA Chapter 5.

To calculate the energy security benefits of the candidate volumes, we are using the ORNL macroeconomic oil security premiums combined with estimates of annual reductions in aggregate net U.S. crude oil imports/petroleum product imports as a result of the candidate volumes. A discussion of the methodology used to estimate changes in U.S. annual net crude oil imports/petroleum product imports from the candidate volumes is provided in RIA Chapter 5. Table IV.B–1 below presents the macroeconomic oil security premiums and the total energy security benefits for the candidate volumes for 2023–2025.

TABLE IV.B–1—MACROECONOMIC OIL SECURITY PREMIUMS AND TOTAL ENERGY SECURITY BENEFITS FOR 2023–2025 [a]

| Year | Macroeconomic oil security premiums (2022$/barrel of reduced imports) | Total energy security benefits (millions 2022$) |
|---|---|---|
| 2023 (Including the supplemental standard) | $3.75<br>($0.86–$6.81) | $192<br>($44–$349) |
| 2023 (Excluding the supplemental standard) | $3.75<br>($0.86–$6.81) | $180<br>($41–$326) |
| 2024 | $3.70<br>($0.69–$6.87) | $173<br>($32–$321) |
| 2025 | $3.67<br>($0.65–$6.87) | $187<br>($33–$350) |

[a] Top values in each cell are the mean values, while the values in parentheses define 90 percent confidence intervals.

[157] Id.

[158] EIA. *Petroleum and Other Liquids Spot Prices. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.*

[159] U.S. Energy Information Administration. 2023. Today in Energy. U.S. Petroleum product exports set a record high in 2022. March.

[160] Id.

[161] Id.

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

[163] See the RIA for more discussion of EPA's assessment of monopsony impacts of this final rule. Also, see the previous EPA GHG vehicle rule for a discussion of monopsony oil security premiums, *e.g.,* Section 3.2.5, Oil Security Premiums Used for this Rule, RIA, Revised 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards, December 2021, EPA–420–F–21–077.

[164] See RIA Chapter 5.4.2 for how the macroeconomic oil security premiums have been updated based upon a review of recent energy security literature on this topic.

*C. Costs*

We assessed the cost impacts for the renewable fuels expected to be used for the candidate volumes relative to a No RFS baseline, described in Section III.D.1. Table III.E–1 provides a summary of the volume changes that we project would occur if the candidate volumes were to be established as applicable volume requirements for 2023–2025, and it is these volume changes relative to the No RFS baseline which we analyzed for costs.

1. Methodology

This section provides a brief discussion of the methodology used to estimate the costs of the candidate volume changes over the years of 2023–2025. A more detailed discussion of how we estimated the renewable fuel costs, as well as the fossil fuel costs being displaced, is contained in RIA Chapter 10.

The cost analysis compares the cost of an increase in biofuel to the cost of the fossil fuel it displaces. There are various components to the cost of each biofuel:

- Production cost: biofuel feedstock cost is usually the prominent factor.
- Distribution cost: Because the biofuel often has a different energy density, the distribution costs are estimated all the way to the point of use to capture the full fuel economy effect of using these fuels.
- Blending value: In the case of ethanol blended as E10, there is a blending value that mostly incorporates ethanol's octane value realized by lower gasoline production costs, but also a volatility cost that accounts for ethanol's blending volatility in RVP controlled gasoline.
- Retail infrastructure cost: In the case of higher ethanol blends, there is a retail cost since retail stations usually need to add equipment or use compatible materials to enable the sale of these newer fuels.
- Fuel economy cost: different fuels have different energy content leading to different fuel economy which impacts the relative fossil fuel volume being displaced and the cost to the consumer.

We added these various cost components together to reflect the cost of each biofuel.

We conducted a similar cost estimate for the fossil fuels being displaced since their relative cost to the biofuels is used to estimate the net cost of the increased use of biofuels. Unlike for biofuels, however, we did not calculate production costs for the fossil fuels since their production costs are inherent in the wholesale price projections provided by the Energy Information Administration in its Annual Energy Outlook 2023.

2. Estimated Cost Impacts

In this section, we summarize the overall results of our cost analysis based on changes in the use of renewable fuels which displace fossil fuel use. The renewable fuel costs presented here do not reflect any tax subsidies for renewable fuels which might be in effect, since such subsidies are transfer payments which are not relevant under a societal cost analysis.[165] A detailed discussion of the renewable fuel costs relative to the fossil fuel costs is contained in RIA Chapter 10.

For each year for which we are finalizing volumes, Table IV.C.2–1 provides the total annual cost of the candidate volumes while Table IV.C.2–2 provides the per-unit cost (per gallon or per thousand cubic feet) of the biofuel. For the year 2023 costs, the estimated costs are shown both without and with the costs associated with the Supplemental Standard renewable fuel volume. For both the total and per-unit cost, the cost of the total change in renewable fuel volume is expressed over the gallons of the respective fossil fuel in which it is blended. For example, the costs associated with corn ethanol relative to that of gasoline are reflected as a cost over the entire gasoline pool, and biodiesel and renewable diesel costs are reflected as a cost over the diesel fuel pool. Biogas displaces natural gas use as CNG in trucks, so it is reported relative to natural gas supply.

TABLE IV.C.2–1—TOTAL SOCIAL COSTS

[Million 2022 dollars] [a]

| | 2023 | 2023 with supplemental standard | 2024 | 2025 |
|---|---|---|---|---|
| Gasoline | 445 | 445 | 423 | 458 |
| Diesel | 7,610 | 8,238 | 6,775 | 7,769 |
| Natural Gas | 55 | 55 | 137 | 228 |
| Total | 8,110 | 8,738 | 7,352 | 8,455 |

[a] Total cost of the renewable fuel expressed over the fossil fuel it is blended into.

TABLE IV.C.2–2—PER-GALLON OR PER-THOUSAND CUBIC FEET COSTS

[2022 dollars]

| | Units | 2023 | 2023 with supplemental standard | 2024 | 2025 |
|---|---|---|---|---|---|
| Gasoline | ¢/gal | 0.33 | 0.33 | 0.31 | 0.34 |
| Diesel | ¢/gal | 13.56 | 14.68 | 12.70 | 14.69 |
| Natural Gas | ¢/thousand $ft^3$ | 0.175 | 0.175 | 0.455 | 0.765 |
| Gasoline and Diesel | ¢/gal | 4.26 | 4.59 | 3.90 | 4.55 |

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

[165] Note that in developing the No RFS baseline we did consider available subsidies other than those provided by the RFS program in determining the volume of renewable fuels that would be used in the absence of the RFS program.

The biofuel costs are higher than the costs of the gasoline, diesel, and natural gas that they displace as evidenced by the increases in fuel costs shown in the above table associated with the candidate volumes. The estimated costs estimated for this final rulemaking are much lower than that estimated for the proposed rulemaking due to two primary factors. The first is that crude oil prices from Annual Energy Outlook 2023, which we used to estimate costs for the FRM, are much higher than that of the proposal which was based on the previous version of the AEO. Higher crude oil prices reduce the relative cost of renewable fuels. The second reason is because of the higher crude oil prices, greater volume of biodiesel and renewable diesel is found to be economic for the No RFS baseline, and so the candidate volumes present a smaller increase in renewable fuels volume relative to the No RFS baseline. As described more fully in RIA Chapter 10, our assessment of costs did not yield a specific threshold value below which the incremental costs of biofuels are reasonable and above which they are not. In Section VI we consider these directional inferences along with those for the other factors that we analyzed in the context of our discussion of the volumes for 2023–2025.

3. Cost To Transport Goods

We also estimated the impact of the candidate volumes on the cost to transport goods. However, it is not appropriate to use the social cost for this analysis because the social costs are effectively reduced by the cellulosic and biodiesel subsidies and other market factors. The per-unit costs from Table IV.C.2–2 are adjusted with estimated RIN prices that account for the biofuel subsidies and other market factors, and the resulting values can be thought of as retail costs. Consistent with our assessment of the fuels markets, we have assumed that obligated parties pass through their RIN costs to consumers and that fuel blenders reflect the RIN value of the renewable fuels in the price of the blended fuels they sell. More detailed information on our estimates of the fuel price impacts of this rule can be found in RIA Chapter 10.5. Table IV.C.3–1 summarizes the estimated impacts of the candidate volumes on gasoline and diesel fuel prices at retail when the costs of each biofuel is amortized over the fossil fuel it displaces.

TABLE IV.C.3–1—ESTIMATED EFFECT OF BIOFUELS ON RETAIL FUEL PRICES

[¢/gal]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Relative to No RFS Baseline: | | | |
| Gasoline | 2.4 | 3.2 | 4.3 |
| Diesel | 10.1 | 10.1 | 11.1 |
| Relative to 2022 Baseline: | | | |
| Gasoline | 0.0 | 0.0 | 0.0 |
| Diesel | 0.0 | −0.4 | −0.1 |

For estimating the cost to transport goods, we focus on the impact on diesel fuel prices since trucks which transport goods are normally fueled by diesel fuel. Reviewing the data in Table IV.C.3–1, the largest projected price increase is 11.1¢ per gallon for diesel fuel in 2025 for the No RFS baseline.

The impact of fuel price increases on the price of goods can be estimated based upon a study conducted by the United States Department of Agriculture (USDA) which analyzed the impact of fuel prices on the wholesale price of produce.[166] Applying the price correlation from the USDA study would indicate that the 11.1¢ per gallon diesel fuel cost increment associated with the 2025 RFS volumes which increases retail prices by about 2.8 percent, would then increase the wholesale price of produce by about 0.7 percent. If produce being transported by a diesel truck costs $3 per pound, the increase in that product's price would be $0.02 per pound.[167] If the estimated program price impacts are averaged over the combined gasoline and diesel fuel pool, the impact on produce prices would be proportionally lower based on the lower per-gallon cost.

*D. Comparison of Impacts*

As explained in Section III of this rule, for those factors for which we quantified the impacts of the candidate volumes for 2023–2025, the impacts were based on the difference in the volumes of specific renewable fuel types between the candidate volumes and the No RFS baseline. The No RFS baseline assumes the RFS program remains intact through 2022 but ceases to exist thereafter. As explained in Section VI, we then go on to finalize these candidate volumes after evaluating them against the statutory factors. Congress provided EPA flexibility by enumerating factors to consider without rigidly mandating the specific steps or manner of analysis that EPA should undertake, including whether the assessment must be quantitative or qualitative. For two of the statutory factors (fuel costs and energy security benefits) we were able to quantify and monetize the expected impacts of the candidate volumes.[168] Information and specifics on how fuel costs are calculated are presented in RIA Chapter 10, while energy security benefits are discussed in RIA Chapter 5. Summaries of the fuel costs and energy security benefits are shown in Tables IV.D–1 and 2. Impacts on other factors, such as job creation and the price and supply of agricultural commodities, are quantified but have not been monetized. Further information and the quantified impacts of the candidate volumes on these factors can be found in the RIA. We were not able to quantify many of the impacts of the candidate volumes, including impacts on many of the statutory factors such as the environmental impacts (water quality and quantity, soil quality, etc.) and rural economic development.

[166] Volpe, Richard; How Transportation Costs Affect Fresh Fruit and Vegetable Prices; United States Department of Agriculture; November 2013.

[167] Comparing Prices on Groceries; May 4, 2021: *http://www.coupons.com/thegoodstuff/comparing-prices-on-groceries.*

[168] Due to the uncertainty related to the GHG emission impacts of the volumes (discussed in further detail in RIA Chapter 4.2) we have not included a quantified projection of the GHG emission impacts of this rule.

TABLE IV.D–1—FUEL COSTS OF THE 2023–2025 VOLUMES

[2022 dollars, millions] [a]

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

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

TABLE IV.D–2—ENERGY SECURITY BENEFITS OF THE 2023–2025 VOLUMES

[2022 dollars, millions]

| Year | Discount rate | | |
|---|---|---|---|
| | 0% | 3% | 7% |
| 2023: | | | |
| Excluding Supplemental Standard | $180 | $180 | $180 |
| Including Supplemental Standard | 192 | 192 | 192 |
| 2024 | 173 | 168 | 162 |
| 2025 | 187 | 177 | 164 |
| Cumulative Discounted Benefits: | | | |
| Excluding Supplemental Standard | 540 | 524 | 505 |
| Including Supplemental Standard | 552 | 536 | 517 |

All of the statutory factors were taken under consideration, as is required by the statute, regardless of whether or not we were able to quantify or monetize the impact of the candidate volumes on each of the statutory factors.

*E. Assessment of Environmental Justice*

Although the statute identifies a number of environmental factors that we must analyze as described in Section I, environmental justice is not explicitly included in those factors. Nonetheless as explained in Section II.B, EPA has discretion under the statute to consider environmental justice, and has chosen to do so. Specifically, EPA views consideration of environmental justice as an aspect of our consideration of the statutory factors ''the impact of the production and use of renewable fuels on the environment,'' ''the impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods,'' and ''the impact of the use of renewable fuels on other factors, including . . . food prices.'' (CAA section 211(o)(2)(B)(ii)(I), (V), (VI)). Our consideration of environmental justice is authorized by and supports our analysis of these statutory factors. However, Executive Orders 12898 (Federal Actions to Address Environmental Justice in Minority Populations, and Low-Income Populations) and 14096 (Revitalizing Our Nation's Commitment to Environmental Justice for All) establish federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on communities with environmental justice concerns in the United States. EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.[169] To the extent that environmental justice (EJ) considerations played a role in our analysis of the candidate volumes and volume requirements, we considered EJ only as it affected the statutory factors in CAA section 211(o)(2)(B)(ii).

[169] E.O. 12898, E.O. 14008, and EPA's guidances do not serve as the legal basis for EPA's consideration of environmental justice in this action. As explained above, the legal basis for EPA's consideration of environmental justice is found in the CAA.

Executive Order 14008 (86 FR 7619; February 1, 2021) also calls on federal agencies to make achieving environmental justice part of their missions ''by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts.'' It also declares a policy ''to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and under-investment in housing, transportation, water and wastewater infrastructure and health care.'' EPA also released its ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis'' (U.S. EPA, 2016) to provide recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time and resource constraints, and analytic challenges will vary by media and circumstance.

When assessing the potential for disproportionately high and adverse health or environmental impacts of regulatory actions on communities with environmental justice concerns, EPA strives to answer three broad questions:

• Is there evidence of potential environmental justice (EJ) concerns in the baseline (the state of the world absent the regulatory action)? Assessing the baseline allows EPA to determine whether pre-existing disparities are associated with the pollutant(s) under consideration (*e.g.,* if the effects of the pollutant(s) are more concentrated in some population groups).

• Is there evidence of potential EJ concerns for the regulatory option(s) under consideration? Specifically, how are the pollutant(s) and its effects distributed for the regulatory options under consideration?

• Do the regulatory option(s) under consideration exacerbate or mitigate EJ concerns relative to the baseline?

It is not always possible to quantitatively assess these questions, though it may still be possible to describe them qualitatively.

EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting an environmental justice analysis, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options. Where applicable and practicable, EPA endeavors to conduct such an analysis. Going forward, EPA is committed to conducting environmental justice analysis for rulemakings based on a framework similar to what is outlined in EPA's Technical Guidance, in addition to investigating ways to further weave environmental justice into the fabric of the rulemaking process.

In accordance with Executive Orders 12898 and 14008, as well as EPA's 2016 Technical Guidance, we have assessed demographics near biofuel and petroleum-based fuel facilities to identify populations that may be affected by changes to fuel production volumes that result in changes to air quality. The displacement of fuels such as gasoline and diesel by biofuels has positive GHG benefits which disproportionately benefit EJ communities. We have also considered the effects of the RFS program on fuel and food prices, as low-income populations often spend a larger percentage of their earnings on these commodities compared to the rest of the U.S.

1. Air Quality

There is evidence that communities with EJ concerns are impacted by non-GHG emissions. Numerous studies have found that environmental hazards such as air pollution are more prevalent in areas where racial/ethnic minorities and people with low socioeconomic status (SES) represent a higher fraction of the population compared with the general population.[170] [171] [172] [173] Consistent with this evidence, a recent study found that most anthropogenic sources of $PM_{2.5}$, including industrial sources, and light- and heavy-duty vehicle sources, disproportionately affect people of color.[174] There is also substantial evidence that people who live or attend school near major roadways are more likely to be of a minority race, Hispanic ethnicity, and/or low socioeconomic status.[175] [176] [177] As this rulemaking would displace petroleum-based fuels with biofuels, we have examined near-facility demographics of biodiesel, renewable diesel, RNG, ethanol, and petroleum facilities.

Emissions of non-GHG pollutants associated with the candidate volumes, including, for example, PM, NOx, CO, $SO_2$, and air toxics, occur during the production, storage, transport, distribution, and combustion of petroleum-based fuels and biofuels.[178] EJ communities may be located near petroleum and biofuel production facilities as well as their distribution systems. Given their long history and prominence, petroleum refineries have been the focus of past research which has found that vulnerable populations near them may experience potential disparities in pollution-related health risk from that source.[179]

RIA Chapter 4.1 summarizes what is known about potential air quality impacts of the candidate volumes assessed for this rule. We expect that small increases in non-GHG emissions from biofuel production and small reductions in petroleum-based emissions would lead to small changes in exposure to these non-GHG pollutants for people living in the communities near these facilities. We do not have the information needed to understand the exact magnitude and direction of travel (*i.e.,* how these potential pollutants drift into nearby areas) of facility-specific emissions associated with the candidate volumes, and therefore we are unable to evaluate impacts on air quality in the specific communities with environmental concerns near biofuel and petroleum facilities. However, modeled averaged facility emissions for biodiesel, ethanol, gasoline, and diesel production do offer some insight into the differences these near-facility populations may experience, as seen in RIA Table 4.1.1–1.

Both biofuel facilities and petroleum refineries could see changes to their production output as a result of candidate volumes analyzed in this proposed rule, and as a result the air quality near these facilities may change. We examined demographics based on 2020 American Community Survey data near both registered biofuel facilities and petroleum refineries to identify any disproportionate impacts these volume changes may have on nearby communities with EJ concerns.[180] Information on these populations and potential impacts upon them are further discussed in RIA Chapter 9. Several regional disparities have been identified in near-refinery populations. For example, people of color and other minority groups near petroleum and renewable diesel facilities are more likely to be disproportionately affected by production emissions from these facilities, especially in EPA Regions 3–7 and Region 9, where a greater proportion of minorities live within a 5

[170] Mohai, P.; Pellow, D.; Roberts Timmons, J. (2009) Environmental justice. Annual Reviews 34: 405–430. *https://doi.org/10.1146/annurev-environ-082508-094348.*

[171] Rowangould, G.M. (2013) A census of the near-roadway population: public health and environmental justice considerations. Trans Res D 25: 59–67. *http://dx.doi.org/10.1016/j.trd.2013.08.003.*

[172] Marshall, J.D., Swor, K.R.; Nguyen, N.P (2014) Prioritizing environmental justice and equality: diesel emissions in Southern California. Environ Sci Technol 48: 4063–4068. *https://doi.org/10.1021/es405167f.*

[173] Marshall, J.D. (2000) Environmental inequality: air pollution exposures in California's South Coast Air Basin. Atmos Environ 21: 5499–5503. *https://doi.org/10.1016/j.atmosenv.2008.02.005.*

[174] C. W. Tessum, D. A. Paolella, S. E. Chambliss, J. S. Apte, J. D. Hill, J. D. Marshall (2021). $PM_{2.5}$ polluters disproportionately and systemically affect people of color in the United States. Sci. Adv. 7, eabf4491.

[175] Rowangould, G.M. (2013) A census of the U.S. near-roadway population: public health and environmental justice considerations. Transportation Research Part D; 59–67.

[176] Tian, N.; Xue, J.; Barzyk. T.M. (2013) Evaluating socioeconomic and racial differences in traffic-related metrics in the United States using a GIS approach. J Exposure Sci Environ Epidemiol 23: 215–222.

[177] Boehmer, T.K.; Foster, S.L.; Henry, J.R.; Woghiren-Akinnifesi, E.L.; Yip, F.Y. (2013) Residential proximity to major highways—United States, 2010. Morbidity and Mortality Weekly Report 62(3): 46–50.

[178] U. S. EPA (2023) Health and environmental effects of pollutants discussed in chapter 4 of regulatory impact analysis (RIA) supporting RFS standards for 2023–2025. Memorandum from Margaret Zawacki to Docket No. EPA–HQ–OAR–2021–0427.

[179] Final Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards, *https://www.epa.gov/sites/default/files/2016-06/documents/2010-0682_factsheet_overview.pdf.*

[180] U.S. EPA (2014). Risk and Technology Review—Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. Jan. 6, 2014.

kilometer radius of these facilities, compared to the regional averages. Some regions are also characterized by a higher proportion of minority populations near facilities, though none more consistently than Regions 4, 6, 7, and 9, which are regions that contain the majority of petroleum facilities and the majority of facilities that are near large population centers. Ethanol and RNG facilities are seen as lower risk compared to soy biodiesel from a demographic perspective, as many ethanol and RNG facilities are in sparsely populated areas or have lower impacts on air quality. RNG facilities introduced to the RFS program may also reduce production emissions by processing otherwise flared biogas in some cases, making the effect of facility production emissions on nearby populations unclear. The candidate volumes by and large would not result in significantly greater production of corn ethanol or biogas than exists already, and therefore we would not expect appreciable adverse impacts on communities with EJ concerns near facilities that are currently producing ethanol or upgrading biogas to RNG during the timeframe of this rule.

2. Other Environmental Impacts

As discussed in RIA Chapter 4.5, the increases in renewable fuel volumes—particularly corn ethanol and soy renewable diesel—that may result from the candidate volumes can impact water and soil quality, which could in turn have disproportionate impacts on communities of concern. In addition, biogas used that is upgraded to RNG may have localized soil or water impacts. The associated manure collection and agricultural anaerobic digesters may decrease pathogen risk in water, but without proper treatment, excess nutrient pollution can also be a concern.

3. Economic Impacts

The candidate volumes could have an impact on food and fuel prices nationwide, as discussed in RIA Chapters 8.5 and 10.5. We estimate that the candidate volumes would result in food prices that are 0.72 percent higher in 2023, 0.63 percent higher in 2024, and 0.55 percent higher in 2025, than the food prices we project with the No RFS baseline. The impacts on food prices decline with the projected decline in commodity prices in future years. These food price impacts are in addition to the higher costs to transport all goods, including food, discussed in Section IV.C.3. These impacts, while generally small, are borne more heavily by low-income populations, as they spend a disproportionate amount of their income on goods in these categories. For instance, those in the bottom two quintiles of consumer income in the U.S. are more likely to be black, women, and people with a high school education or less, while also spending a proportionally larger fraction of their income on food and fuel. The lowest quintile of consumer units by income will spend 16 percent of their income on food as a result of the RFS program, up from 15.8 percent currently, while the second lowest quintile of consumer units by income will spend 13.4 percent of their income on food as a result of the RFS program, up from 13.2 percent currently. These absolute values can be seen in Table IV.E.3–1.

TABLE IV.E.3–1—IMPACT ON TOTAL EXPENDITURES OF FOOD AND FUEL [181]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| **All Consumer Units** | | | |
| Food Expenditures | $8,289 | $8,289 | $8,289 |
| Percent Impact on Food Expenditures | 0.61% | 0.50% | 0.44% |
| Projected Food Expenditure Increase | $50.56 | $41.45 | $36.59 |
| Fuel Expenditures | $2,148 | $2,148 | $2,148 |
| Percent Impact on Fuel Expenditures | 0.79% | 1.23% | 1.73% |
| Projected Fuel Expenditure Increase | $16.97 | $26.42 | $37.24 |
| **Lowest Quintile Income Consumer Units** | | | |
| Food Expenditures | $4,875 | $4,875 | $4,875 |
| Percent Impact on Food Expenditures | 0.61% | 0.50% | 0.44% |
| Projected Food Expenditure Increase | $29.74 | $24.38 | $21.52 |
| Fuel Expenditures | $1,111 | $1,111 | $1,111 |
| Percent Impact on Fuel Expenditures | 0.79% | 1.23% | 1.73% |
| Projected Fuel Expenditure Increase | $8.78 | $13.67 | $19.22 |
| **Second-Lowest Quintile Income Consumer Units** | | | |
| Food Expenditures | $5,808 | $5,808 | $5,808 |
| Percent Impact on Food Expenditures | 0.61% | 0.50% | 0.44% |
| Projected Food Expenditure Increase | $35.43 | $29.04 | $25.63 |
| Fuel Expenditures | $1,702 | $1,702 | $1,702 |
| Percent Impact on Fuel Expenditures | 0.79% | 1.23% | 1.73% |
| Projected Fuel Expenditure Increase | $13.45 | $20.93 | $29.44 |

## V. Response to Remand of 2016 Rulemaking

In this action, we are completing the process of addressing the remand of the 2014–2016 annual rule by the U.S. Court of Appeals for the D.C. Circuit in *ACE*.[182] [183] As discussed in the final rule

[181] Bureau of Labor and Statistics Consumer Expenditure Survey, 2022. *https://www.bls.gov/cex/tables/calendar-year/aggregate-group-share/cu-income-quintiles-before-taxes-2020.pdf.*

[182] 80 FR 77420 (December 14, 2015). In the 2014–2016 rule, for year 2016 EPA lowered the cellulosic biofuel requirement by 4.02 billion gallons and the advanced biofuel and total renewable fuel requirements each by 3.64 billion gallons pursuant to the cellulosic waiver authority. CAA section 211(o)(7)(D). In the same rule, EPA further lowered the 2016 total renewable fuel requirement by 500 million gallons under the general waiver authority for inadequate domestic supply. CAA section 211(o)(7)(A).

[183] In 2017, the D.C. Circuit vacated EPA's use of the general waiver authority for inadequate

establishing applicable standards for 2020–2022,[184] our approach to address the *ACE* remand is to impose a 500-million-gallon supplemental volume requirement for renewable fuel over two years. This is equivalent to the volume of renewable fuel waived from the 2016 statutory volume requirement using a waiver which was subsequently vacated by the D.C. Circuit.[185] We required the first 250-million-gallon supplement in 2022. We are now requiring a second 250-million-gallon supplement to be complied with in 2023. This 2023 supplemental volume requirement, in combination with the 2022 supplement, constitutes a meaningful remedy and completes our response to the *ACE* vacatur and remand.

In the final rule establishing applicable standards for 2020–2022, we discussed the original 2016 renewable fuel standard, the *ACE* court's ruling, and our responsibility on remand in detail.[186] We also discussed our consideration of alternative approaches to respond to the remand.[187] We maintain the same views on the alternatives, including the alternatives identified by commenters, discussed in that rulemaking, and since that rulemaking have not identified any additional alternative approaches to addressing the *ACE* vacatur and remand. In particular, because we have already begun our response by imposing a 250-million-gallon supplemental standard in 2022, consideration of any other alternatives is evaluated in light of that partial response.

### *A. Supplemental 2023 Standard*

We are completing the process of addressing the *ACE* remand by applying a supplemental volume requirement of 250 million gallons of renewable fuel in 2023, on top of and in addition to the other 2023 volume requirements.

Under this approach, the original 2016 standard for total renewable fuel will remain unchanged and the compliance demonstrations that obligated parties made for it will likewise remain in place. A supplemental standard for 2023 avoids the difficulties associated with reopening 2016 compliance, as discussed in detail in the 2020–2022 proposed rulemaking.[188] This supplemental standard has the same practical effect as increasing the 2023 total renewable fuel volume requirement by 250 million gallons, as compliance will be demonstrated using the same RINs as used for the 2023 standard. The percentage standard for the supplemental standard is calculated the same way as the 2023 percentage standards (*i.e.,* using the same gasoline and diesel fuel projections), such that the supplemental standard is additive to the 2023 total renewable fuel percentage standard. This approach provides a meaningful remedy in response to the court's vacatur and remand in *ACE* and effectuates the Congressionally determined renewable fuel volume for 2016, modified only by the proper exercise of EPA's waiver authorities, as upheld by the court in *ACE* and in a manner that can be implemented in the near term. We are treating such a supplemental standard as a supplement to the 2023 standards, rather than as a supplement to standards for 2016, which has passed. In order to comply with the supplemental standard, obligated parties will need to retire available RINs; it is thus logical to require the retirement of available RINs in the marketplace at the time of compliance with this supplemental standard. As discussed below, it is no longer possible for obligated parties to comply with a 500-million-gallon 2016 obligation using 2015 and 2016 RINs as required by our regulations. Thus, compliance with a supplemental standard applied to 2016 would be impossible barring EPA reopening compliance for all years from 2016 onward. By applying the supplemental standard to 2023 instead of 2016, RINs generated in 2022 and 2023 can be used to comply with the 2023 supplemental standard. Additionally, as provided by our regulations, RINs generated in 2015 and 2016 could only be used for 2015 and 2016 compliance demonstrations,[189] and obligated parties had an opportunity at that time to utilize those RINs for compliance or sell them to other parties, while holding RINs that could be utilized for future compliance years.

In applying a supplemental standard to 2023, we are treating it like all other 2023 standards in all respects. That is, producers and importers of gasoline and diesel that are subject to the 2023 standards are subject to the supplemental standard. The applicable deadlines for attest engagements and compliance demonstrations that apply to the 2023 standards also apply to the supplemental standard. The gasoline and diesel volumes used by obligated parties to calculate their obligation is their 2023 gasoline and diesel production or importation. Additionally, obligated parties can use 2022 RINs for up to 20 percent of their 2023 supplemental standard.

Stakeholders provided comments on this approach, with some supporting EPA's approach to the remand, and others suggesting that EPA should take an alternative response. We respond to those comments in the RTC document.

#### 1. Demonstrating Compliance With the 2023 Supplemental Standard

As we did for the 2022 supplemental standard, we are prescribing formats and procedures as specified in 40 CFR 80.1451(j) for how obligated parties will demonstrate compliance with the 2023 supplemental standard that simplifies the process in this unique circumstance. Although the proposed 2023 supplemental standard is a regulatory requirement separate from and in addition to the 2023 total renewable fuel standard, obligated parties will submit a single annual compliance report for both the 2023 annual standards and the supplemental standard and will only report a single number for their total renewable fuel obligation in the 2023 annual compliance report. Obligated parties will also only need to submit a single annual attest engagement report for the 2023 compliance period that covers both the 2023 annual standards and the 2023 supplemental standard.

To assist obligated parties with this special compliance situation, we will issue guidance with instructions on how to calculate and report the values to be submitted in their 2023 compliance reports, similar to how we intend to do so for 2022.

#### 2. Calculating a Supplemental Percentage Standard for 2023

The formulas in 40 CFR 80.1405(c) for calculating the applicable percentage standards were designed explicitly to associate a percentage standard for a particular year with the volume requirement for that same year. The formulas are not explicitly designed to address the use of a 2016 volume requirement to calculate a 2023 percentage standard. Nonetheless, in light of EPA's and obligated parties' familiarity with this approach and the benefits of consistency within the structure of RFS regulations, we find it appropriate to apply the same general approach to calculating a supplemental

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domestic supply to reduce the 2016 total renewable fuels standard by 500 million gallons and remanded the 2014–2016 rule. 864 F.3d 691 (2017).

[184] 87 FR 39600, 39627–39631 (July 1, 2022).

[185] 864 F.3d at 691.

[186] 87 FR 39600, 39627–39628 (July 1, 2022).

[187] 87 FR 39600, 39628–39629 (July 1, 2022). We also responded to alternative ideas provided by commenters. See also Renewable Fuel Standard (RFS) Program: RFS Annual Rules Response to Comments, EPA–420–R–22–009 at 151–154.

[188] 86 FR 72436, 72459–72460 (Dec. 21, 2022).

[189] 2016 RINs could also have been used for up to 20 percent of an obligated party's 2017 compliance demonstrations.

percentage standard for 2023. Utilizing the same principles and general terms allows for a formula that properly utilizes the 250 million gallon supplemental volume, but the same values used to calculate the 2023 percentage standards, such that the supplemental percentage standard is still properly additive.

The numerator in the formula in 40 CFR 80.1405(c) is the supplemental volume of 250 million gallons of total renewable fuel. The values in the denominator are the same as those used to calculate the 2023 percentage standards, which can be found in Table VII.C–1. As described in Section VII, the resulting supplemental total renewable fuel percentage standard for the 250-million-gallon volume requirement in 2023 is 0.14 percent.

The supplemental standard for 2023 is a requirement for obligated parties separate from and in addition to the 2023 standard for total renewable fuel. The two percentage standards are listed separately in the regulations at 40 CFR 80.1405(a), but in practice obligated parties will demonstrate compliance with both at the same time.

### *B. Authority and Consideration of the Benefits and Burdens*

In establishing the 2016 total renewable fuel standard, EPA waived the required volume of total renewable fuel by 500 million gallons using the inadequate domestic supply general waiver authority. The use of that waiver authority was vacated by the court in *ACE* and the rule was remanded to EPA. In order to remedy our improper use of the inadequate domestic supply general waiver authority, we find that it is appropriate to treat our authority to establish a supplemental standard at this time as the same authority used to establish the 2016 total renewable fuel volume requirement—CAA section 211(o)(3)(B)(i)—which requires EPA to establish percentage standard requirements by November 30 of the year prior to which the standards will apply and to ''ensure'' that the volume requirements ''are met.'' [190] EPA exercised this authority for the 2016 standards once already. However, the effect of the *ACE* vacatur is that there remain 500 million gallons of total renewable fuel from the 2016 statutory volumes that were not included under the original exercise of EPA's authority under CAA section 211(o)(3)(B)(i). We are now utilizing the same authority to correct our prior action, and ''ensure'' that the volume requirements ''are met,'' and we are doing so significantly after November 30, 2015. Therefore, we have considered how to balance benefits and burdens and mitigate hardship by our late issuance of this standard. We recognize that we used the same authority to establish the 2022 supplemental standard. As noted in that action, we had only provided a partial response to the *ACE* court's remand and vacatur. This action now completes our response. Additionally, as we have in the past, we rely on our authority in CAA section 211(o)(2)(A)(i) to promulgate late standards.[191] CAA section 211(o)(2)(A)(i) requires that EPA ''ensure'' that ''at least'' the applicable volumes ''are met.'' [192] Because the D.C. Circuit vacated our waiver of 500 million gallons of total renewable fuel from the original 2016 standards, we are now taking action to ensure that at least the applicable volumes from 2016 are ultimately met. We have determined that the appropriate means to do so is through the use of two 250-million-gallon supplemental standards, one in 2022, as finalized in a prior action, and one in 2023, as we are finalizing in this action.

As noted elsewhere, we are finalizing this action during the 2023 compliance year. Thus, our action is partly retroactive as to the compliance with the supplemental standard by obligated parties. In analyzing the benefits and burdens attendant to this approach, we have also considered the partially retroactive nature of the rule. The issuance of the supplemental standard is thus a late standard, in that we are acting beyond the statutory deadline for a standard associated with the 2016 volume requirements, and it is partially retroactive as it is being finalized partway through the compliance year during which it applies.

In *ACE* and two prior cases, the court upheld EPA's authority to issue late renewable fuel standards, even those applied retroactively, so long as EPA's approach is reasonable.[193] EPA must consider and mitigate the burdens on obligated parties associated with a delayed rulemaking.[194] When imposing a late or retroactive standard, we must balance the burden on obligated parties of a retroactive standard with the broader goal of the RFS program to increase renewable fuel use.[195] The approach in this action implements a late standard, with partially retroactive effects, as described in these cases. Obligated parties made their RIN acquisition decisions in 2016 based on the standards as established in the 2014–2016 standards final rule, and they may have made different decisions had we not reduced the 2016 total renewable fuel standard by 500 million gallons using the general waiver authority. Were EPA to create a supplemental standard for 2016 designed to address the use of the general waiver authority in 2016, we would be imposing a wholly retroactive standard on obligated parties, but because obligated parties will comply with the supplemental standard in 2023, it would instead be a late standard applied in 2023, with partially retroactive effects. Pursuant to the court's direction, we have carefully considered the benefits and burdens of our approach and considered and mitigated the burdens to obligated parties caused by the lateness.[196]

We believe that the approach we are finalizing provides benefits that outweigh potential burdens. Consistent with the 2016 renewable fuel volume requirement established by Congress, the supplemental standards for 2022 and 2023 are together equivalent to the volume of total renewable fuel that we inappropriately waived for the 2016 total renewable fuel standard. The use of these supplemental standards phased across two compliance years provides a meaningful remedy to the D.C. Circuit's vacatur of EPA's use of the general waiver authority and remand of the 2016 rule in *ACE.* While this action cannot result in additional renewable fuel used in 2016, it can result in additional fuel use in 2023. We believe that while the additional volume in 2023 will put some moderate degree of increased pressure on the market, it is nevertheless feasible and achievable.

We have carefully considered and designed this approach to mitigate any burdens on obligated parties. First, we have considered the availability of RINs to satisfy this additional requirement. As explained earlier, there are insufficient 2015 and 2016 RINs

[190] EPA acknowledges that CAA section 211(o)(3)(B)(i) does not apply to the standards for 2023–2025. EPA cites this authority for the supplemental standard which is a 2016 standard with compliance aligned with calendar year 2023.

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

[192] See also CAA section 211(o)(2)(A)(iii)(I), requiring that ''regardless of the date of promulgation,'' EPA shall promulgate ''compliance provisions applicable to refineries, blenders, distributors, and importers, as appropriate, to ensure that the requirements of this paragraph are met.''

[193] See *ACE,* 864 F.3d at 718; *Monroe Energy, LLC* v. *EPA,* 750 F.3d at 920; *NPRA,* 630 F.3d at 154–58.

[194] *ACE,* 864 F.3d at 718.

[195] *NPRA,* 630 F.3d at 154–58.

[196] As we also did for the 2022 supplemental standard. 87 FR 39629–31 (July 1, 2022).

available to satisfy the proposed 250-million-gallon volume requirement. Instead, we are finalizing a supplemental volume requirement to the 2023 standards that applies prospectively, in part. Doing so allows 2022 and 2023 RINs to be used for compliance with the 2023 supplemental standard, in keeping with existing RFS regulations. We believe there will be a sufficient number of 2023 RINs to satisfy the 2023 supplemental standard through a combination of domestic production and importation of renewable fuel, as described more fully in Section VI. In Section VI and RIA Chapter 6.2.6, we considered the feasibility and achievability of the 2023 supplemental standard alongside the other volume standards for 2023. We believe that compliance through the use of carryover RINs will not be necessary, but nevertheless remains available as an option for obligated parties for compliance.[197]

Second, we provided significant lead-time for obligated parties by proposing this supplemental standard for 2023 no less than 12 months prior to the 2023 compliance deadline.[198] Moreover, we initially provided obligated parties notice of the 250-million-gallon supplemental standard for 2022 in December of 2021,[199] no less than 24 months prior to the 2023 compliance deadline, and indicated our intention to similarly apply a 250-million-gallon supplemental standard to 2023. Given this December 2021 statement of intent, parties have had notice of a 250-million-gallon supplemental standard in 2023 for longer than they had notice of the 2023 standards for renewable fuel, advanced biofuel, and total renewable fuel. We are also finalizing this action approximately 9 months prior to the 2023 compliance deadline.

Third, we are finalizing multiple mechanisms to mitigate the potential compliance burden caused by a late rulemaking. One step is to designate that the response to the *ACE* remand is a supplement to the 2023 standards. This approach not only allows the use of 2022 and 2023 RINs for compliance with the 2023 standard, as described earlier, but it also avoids the need for obligated parties to revise their 2016 (and potentially 2017, 2018, 2019, etc.) compliance demonstrations, which would be a burdensome and time-consuming process. In addition, obligated parties can satisfy both the 2023 standards and the supplemental standard in a single set of compliance and attest engagement demonstrations. We are also extending the same compliance flexibility options already available for the 2023 standards to the 2023 supplemental standard, including allowing the use of carryover RINs and deficit carry forward subject to the conditions of 40 CFR 80.1427(b)(1). With this action we are also spreading out the 500-million-gallon obligation over two compliance years. As explained in the 2020–2022 final rule, this is designed to allow obligated parties and renewable fuel producers additional lead time to meet the standard, thus providing almost a year for the market to prepare for compliance with the second 250-million-gallon requirement.[200]

Lastly, we carefully considered alternatives, including retaining the 2016 total renewable fuel volume as described in the 2020 proposal,[201] reopening 2016 compliance and applying a supplemental standard to the 2016 compliance year,[202] and, as suggested by commenters on the 2020–2022 rule, using our cellulosic or general waiver authority to retroactively lower 2016 volumes such that 2022 and 2023 supplemental standards would be smaller.[203]

On balance, we find that requiring an additional 250 million gallons of total renewable fuel to be complied with through a supplemental standard in 2023 in addition to that already applied in 2022 is an appropriate response to the court's vacatur and remand of our use of the general waiver authority to waive the 2016 total renewable fuel standard by 500 million gallons.

## VI. Volume Requirements for 2023–2025

As required by the statute, we have reviewed the implementation of the program in prior years and have analyzed a specified set of factors.[204] As described in Section III, we did this by first deriving a set of ''candidate volumes'' based on a consideration of supply-related factors and other relevant factors, and then using those candidate volumes to analyze the remaining economic and environmental factors as discussed in Section IV. Details of all analyses are provided in the RIA. We have coordinated with the Secretary of Energy and the Secretary of Agriculture, including through the interagency review process, and their input is reflected in this final rule. We have also considered all information provided through comments from stakeholders and any other information that has become available since release of the proposal.

In this section, we summarize and discuss the implications of all our analyses and any other information that has become available as it applies to each of the three different component categories of biofuel: cellulosic biofuel, non-cellulosic advanced biofuel, and conventional renewable fuel. These three components combine to produce the statutory categories: the volume requirement for advanced biofuel is equal to the sum of cellulosic biofuel and non-cellulosic advanced biofuel, while the volume requirement for total renewable fuel is equal to the sum of advanced biofuel and conventional renewable fuel.[205]

We note that while we do not separately discuss each of the statutory factors for each component category in this section, we have analyzed all the statutory factors. However, it was not always possible to precisely identify the implications of the analysis of a specific factor for a specific component category of renewable fuel. For instance, while we analyzed ethanol use in the context of the review of the implementation of the program in prior years, ethanol can be used in all biofuel categories except BBD and our analysis therefore does not apply to a single standard. Air quality impacts are driven primarily by biofuel type (*e.g.,* ethanol, biodiesel, etc.) rather than by biofuel category, and energy security impacts are driven solely by the amount of fossil fuel energy displaced. Moreover, with the exception of CAA section 211(*o*)(2)(ii)(III), the statute does not require that the requisite analyses be specific to each category of renewable fuel. Rather, the statute directs EPA to analyze certain factors, without specifying how that analysis must be conducted. In addition, the statute directs EPA to analyze the ''program'' and the impacts of ''renewable fuels'' generally, further indicating that Congress intended to provide to EPA the discretion to decide how and at what level of specificity to analyze the statutory factors. This section

[197] See Section III.C.4 for further discussion of carryover RINs.

[198] See 40 CFR 80.1427. See also *Nat'l Petrochemical & Refiners Ass'n* v. *EPA,* 630 F.3d 145, 166 (D.C. Cir.), acknowledging 11 months from issuance of standards to the compliance deadline as sufficient time, and *ACE* at 722–23 acknowledging ''very extensive extensions of the normal compliance demonstration deadlines'' of approximately 8 months after signature.

[199] 86 FR 72436 (December 21, 2021).

[200] 87 FR 39600 (July 1, 2022).

[201] 84 FR 36762, 36787–36789 (July 29, 2019).

[202] 86 FR 72459–60.

[203] 87 FR 39600 (July 1, 2022). See also Chapter 8 of the Response to Comments document for this action.

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

[205] These combinations are set forth in the statute. See CAA section 211(o)(2)(B)(i)(I)–(III). In addition, the determination of the appropriate volume requirements for BBD is treated separately in Section VI.C.

supplements the analyses discussed in Sections III and IV by providing a narrative summary of the key criteria that apply distinctively to each component category insofar as we have deemed appropriate.

*A. Cellulosic Biofuel*

In EISA, Congress established escalating targets for cellulosic biofuel, reaching 16 billion gallons in 2022. After 2015, all of the growth in the statutory volume of total renewable fuel was advanced biofuel, and of the advanced biofuel growth, the vast majority was cellulosic biofuel. This indicates that Congress intended the RFS program to provide a significant incentive for cellulosic biofuels and that the focus for years after 2015 was to be on cellulosic. While cellulosic biofuel production has not reached the levels envisioned by Congress in 2007, EPA remains committed to supporting the development and commercialization of cellulosic biofuels. Cellulosic biofuels, particularly those produced from waste or residue materials, have the potential to significantly reduce GHG emissions from the transportation sector. In many cases cellulosic biofuel can be produced without impacting current land use and with little to no impact on other environmental factors, such as air and water quality. The cellulosic biofuel volumes we are finalizing are intended to provide the necessary support for the ongoing development and commercial scale deployment of cellulosic biofuels, and to continue to build towards the Congressional target of 16 billion gallons of cellulosic biofuel established in EISA, and are supported by our consideration of the specified statutory factors.

As discussed in Section III.B.1, we developed candidate volumes for cellulosic biofuel based on a consideration of statutory supply-related factors. This process included a consideration not only of production and import of the different possible forms of cellulosic biofuel, but also of constraints on consumption (*i.e.,* the number of CNG/LNG vehicles) and of the availability of qualifying feedstocks, primarily but not exclusively biogas. With an eye towards estimating candidate volumes based on the supply-related statutory factors that reflect the projected growth in cellulosic biofuel production from 2023–2025, we estimated the following candidate volumes:

TABLE VI.A–1—CANDIDATE VOLUMES OF CELLULOSIC BIOFUEL

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| CNG/LNG Derived from Biogas | 831 | 1,039 | 1,299 |
| Ethanol from CKF | 7 | 51 | 77 |
| Total Cellulosic Biofuel | 838 | 1,090 | 1,376 |

We then analyzed these candidate volumes according to the other statutory factors. These analyses are discussed briefly here and described in greater detail in the RIA. Our assessment of those factors suggests that cellulosic biofuels have multiple benefits, including the potential for very low lifecycle GHG emissions that meet or exceed the statutorily-mandated 60 percent GHG reduction threshold for cellulosic biofuel.[206] Many of these benefits stem from the fact that nearly all of the feedstocks projected to be used to produce the candidate cellulosic biofuel volumes are either waste materials (as in the case of CNG/LNG derived from biogas) or residues (as in the case of cellulosic diesel and heating oil from mill residue). The use of many of the feedstocks currently being used to produce cellulosic biofuel and those expected to be used through 2025 (primarily biogas to produce CNG/LNG) are not expected to cause significant land use changes that might lead to adverse environmental impacts.

None of the cellulosic biofuel feedstocks expected to be used to produce liquid cellulosic biofuels through 2025 (including agricultural residues such as corn kernel fiber, mill residue, and separated MSW) are produced with the intention that they be used as feedstocks for cellulosic biofuel production. Moreover, many of these feedstocks have limited uses in other markets.[207] Because of this, using these feedstocks to produce liquid cellulosic biofuel is not expected to have significant adverse impacts related to several of the statutory factors, including the conversion of wetlands, ecosystems and wildlife habitat, soil and water quality, the price and supply of agricultural commodities, and food prices through 2025.

Despite the fact that both liquid cellulosic biofuels and CNG/LNG derived from biogas are projected to be produced from feedstocks that are wastes or by-products, there are also significant differences between liquid cellulosic biofuels and CNG/LNG derived from biogas. In particular, the cost of producing liquid cellulosic biofuel is generally high. These high costs are generally the result of low yields (*e.g.,* gallons of fuel per ton of feedstocks) and the high capital costs of liquid cellulosic biofuel production facilities. In the near term (through 2025), the production of these fuels is likely to be dependent on relatively high cellulosic RIN prices (in addition to state level programs such as California's LCFS) in order for them to be economically competitive with petroleum-based fuels.

In contrast to liquid cellulosic biofuels, cellulosic biofuels derived from biogas, most notably CNG/LNG, can be more cost-competitive with the fuels they displace. Some biogas from qualifying sources such as landfills, wastewater treatment facilities, and agricultural digesters are already injected into natural gas pipelines.[208] In some situations, such as at larger landfills, CNG/LNG derived from biogas may be able to be produced at a price comparable to fossil natural gas. In most cases, however, some financial incentive is needed to enable these fuels to compete economically with the fuels they displace. Because of the low cost of production relative to liquid cellulosic biofuels and the relatively mature state of this technology, CNG/LNG from biogas is expected to remain as the dominant type of cellulosic biofuel through 2025.

[206] CAA section 211(o)(1)(E).

[207] One potential exception is corn kernel fiber. Corn kernel fiber is a component of distillers grains, which is currently sold as animal feed. Depending on the type of animal to which the distillers grain is fed, corn kernel fiber removed from the distillers grain through conversion to cellulosic biofuel may need to be replaced with additional feed.

[208] See Landfill Gas Energy Project Data from EPA's Landfill Methane Outreach Program.

Despite the relatively low cost of production for CNG/LNG derived from biogas, the combination of the relatively high cellulosic biofuel RIN price and the significant volume potential for CNG/LNG derived from biogas used as transportation fuel could have an impact on the price of gasoline and diesel. We project that together these fuels could add about $0.01 per gallon to the price of gasoline and diesel in 2023, and that this price impact could rise to about $0.02 per gallon in 2025.[209]

Based on our analyses of all of the statutory factors, 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 candidate levels that reflect the projected growth in cellulosic biofuel production from 2023–2025 based on available data. The volumes for 2023–2025 we are finalizing in this rule are based on the data available at the time of this rule and reflect our consideration of the public comments received on the proposed rule. These volumes represent our best efforts to project the potential for growth in the volume of these fuels that can be achieved in 2023–2025. We believe these volumes will continue to provide substantial support for investment in and development of cellulosic biofuels and yet are consistent with statutory requirements for the cellulosic biofuel volumes (including CAA 211(o)(2)(B)(iv)).

TABLE VI.A–2—FINAL CELLULOSIC BIOFUEL VOLUMES

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| CNG/LNG Derived from Biogas | 831 | 1,039 | 1,299 |
| Ethanol from CKF | 7 | 51 | 77 |
| Total Cellulosic Biofuel | 838 | 1,090 | 1,376 |

We note that the final cellulosic biofuel volumes are higher than the proposed volumes, after accounting for the decision not to finalize eRIN provisions in this rule. There are several reasons for these higher volumes, which are discussed briefly here and in more detail in Section III.B and RIA Chapter 6. The addition of projected volume of cellulosic ethanol from CKF relative to the proposed rule is largely the result of the significant progress several facilities and technology providers have made towards facility registration since the release of the updated guidance of producing ethanol from corn kernel fiber.[210] As discussed in RIA Chapter 6.1, since the proposed rule EPA has received registration requests from facilities intending to register to generate cellulosic biofuel RINs for ethanol from CKF, and have had substantive technical discussions with technology providers who intend to provide testing results consistent with EPA's current guidance. The increases in CNG/LNG derived from biogas are due to our belief that growth from 2023–2025 can be more in line with the average growth from 2015–2022 rather than just the most recent 24 months.

We recognize that with this Set rule Congress has instructed us to begin a new phase of the RFS program, one in which there are no statutory volume targets. This has important implications for the use of our cellulosic waiver authority and the availability of cellulosic waiver credits in future years (see Section II.F for a further discussion of the availability of cellulosic waiver credits). In the proposed rule we noted several important changes in EPA's statutory authority in years after 2022, and we sought input from commenters on how these changes can or should impact the required cellulosic biofuel volumes. These comments, and our responses to them, are discussed briefly here, and in greater detail in RTC Sections 2.3.2 and 3.1.

Perhaps most importantly EPA proposed volumes for multiple years in one action in an effort to provide the consistent market signals that the cellulosic biofuel industry needs to develop. At the same time, we recognized that there is increased uncertainty in any cellulosic biofuel projections due to the multi-year nature of this rule and the potential for the development and deployment of new cellulosic biofuel production pathways. The increasing cellulosic biofuel volumes that we are establishing in this rule should also provide increased stability in the cellulosic RIN market, as they allow greater volumes of cellulosic RINs to be used for compliance in the following year if excess cellulosic RINs are generated. We believe that despite the uncertainty associated with cellulosic biofuel production through 2025 it is appropriate to finalize cellulosic biofuel volumes for 2023–2025 in this rule, and that the cellulosic biofuel volumes we are finalizing are reasonable based on the available data for making future projections.

In the proposed rule we noted that several stakeholders had stated that despite the incentive provided by the RFS program, variability and uncertainty in cellulosic RIN prices and future cellulosic biofuel requirements are hindering investment in the cellulosic biofuel industry. These parties generally expressed concerns related to the potential impacts on the cellulosic biofuel and cellulosic RIN markets if EPA's projections of cellulosic biofuel are significantly and consistently lower than the actual production of cellulosic biofuel. While many stakeholders acknowledged that EPA has tools to reduce the cellulosic biofuel volumes if necessary, they noted that EPA has a limited ability to increase the cellulosic biofuel volume if production and imports of cellulosic biofuel exceed the required volumes. In such a case the stakeholders expressed concern that the price of cellulosic RINs could fall to a level at or approaching the advanced biofuel RIN price, which might then negatively impact their investment in cellulosic biofuel production.

We agree with these commenters that it is important to maintain proper incentives for investment in and growth

[209] See RIA Chapters 1.9.2 and 10 for a further discussion of the expected impact of RINs generated for CNG/LNG derived from biogas on the price of gasoline and diesel and the impact of CNG/LNG derived from biogas on the cost of this rule.

[210] Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch. Compliance Division, Office of Transportation and Air Quality, U.S. EPA. September 2022 (EPA–420–B–22–041). See RIA Chapter 6.1 for a further discussion of ethanol produced form corn kernel fiber.

of cellulosic biofuels. Their potential for greater GHG emission reductions and typically limited negative environmental impacts make them attractive options for displacing petroleum fuels. Since 2015, the incentives provided by the RFS program have supported significant growth in cellulosic biofuel production (see Figure III.B.1–1). During this time, cellulosic biofuel production has grown at an annual rate of 25% per year, greater than any other category of cellulosic biofuel. In response to comments received on the proposed rule and more recent data we have adjusted our approach to projecting the potential production of CNG/LNG derived from biogas (by far the largest source of cellulosic biofuel) to better reflect the potential for the growth of these fuels through 2025. This higher growth rate resulted in significantly higher, yet still achievable, projections for CNG/LNG derived from biogas.

We believe that the most effective and direct way to respond to the concerns the commenters raised with respect to the negative impacts related to a potential surplus of cellulosic biofuel RINs is to establish cellulosic biofuel volume requirements that reflect the projected growth of the cellulosic biofuel industry based on available data, as we have done in this final rule.

Nevertheless, in their comments on the proposed rule these stakeholders requested that EPA modify our historical standard setting process for cellulosic biofuel to also commit to a mechanism for increasing the cellulosic biofuel volume requirements if actual production and imports exceeded the volumes we are finalizing in this rule by a specified amount, either by adopting regulatory provisions that would automatically increase the volume requirement or by committing to adjusting the cellulosic biofuel volume requirements in a subsequent rule. The most common mechanism requested by commenters was that EPA would finalize a formula that would be used annually to adjust the required volume of cellulosic biofuel for a subsequent year.[211] For example, many parties suggested that EPA should calculate the difference between (1) the total number of cellulosic RINs generated in each year plus any remaining cellulosic RINs from the previous year not used for compliance and (2) the required cellulosic biofuel volume for that year. If the quantity of cellulosic RIN generation plus carryover RINs exceeded the required volume for that year, these parties stated that EPA should automatically increase the required cellulosic volume for a subsequent year.[212] By doing so the commenters believed that cellulosic biofuel RIN values would be assured of remaining high, reducing their investment risk. If the quantity of cellulosic RIN generation plus carryover RINs was less than the required volume for that year creating a concern for obligated parties, then the commenters suggested EPA should automatically decrease the required cellulosic volume for a subsequent year.

Several commenters opposed the adoption of a mechanism that would automatically adjust the cellulosic volumes.[213] These comments generally focused on the statutory requirements that the RFS volume requirements be based on an evaluation of the statutory criteria (rather than a simple calculation) and that the volume requirements be set 14 months in advance of the applicable year. One commenter additionally noted that EPA should not use any adjustment mechanism to reduce the available carryover RINs, which they claimed were allowed by Congress. Another commenter stated that any formula that could result in adjusting the cellulosic volume requirements downward would strip the RFS program of its market forcing power and result in only requiring the quantity of cellulosic biofuel actually used in the market.

We acknowledge that in theory a mechanism could be developed and implemented in a way that might be able to reduce, and potentially even eliminate, the investment risk associated with a potential surplus of cellulosic RINs causing RIN price volatility or lower RIN prices. Nevertheless, after reviewing these comments, EPA is not committing to such a mechanism at this time for the following reasons and as discussed more fully in RTC Section 2.3.

First, as discussed above, we believe that the most effective and direct way to respond to the concerns the commenters raised with respect to the negative impacts related to a potential surplus of cellulosic biofuel RINs is to establish cellulosic biofuel volume requirements that reflect the projected growth of the cellulosic biofuel industry based on available data.

Second, it is not yet clear how such a mechanism could or should be implemented. For example, the public data many of the commenters suggested could be used in these calculations are not clearly suitable for this purpose. With the new biogas regulatory reform provisions (discussed in Section IX) that we are finalizing in this rule, not all D3 biogas RINs generated will represent cellulosic fuel used as transportation fuel. Under the new provisions, these RINs may be retired if the RNG is used for a non-transportation use (*e.g.,* heating or renewable electricity generation), thus altering the ultimate amount of cellulosic RINs available to meet the RFS standards.

Third, EPA also has an obligation to provide public notice and an opportunity for comment prior to establishing the RFS volume requirements. While we sought comment on an adjustment mechanism in general, and commenters provided input on potential mechanisms at a high level, there was little specificity associated with how such a mechanism could or would be implemented in practice. Notably we did not propose regulations for public comment that would implement an adjustment mechanism. While some commenters acknowledged this notice and comment obligation, these commenters did not adequately address the potential public notice concerns that finalizing this approach may now raise. While EPA could in theory promulgate a supplemental notice and opportunity for comment on this change, doing so would further and significantly delay this rulemaking, which would be inconsistent with the lead-time provisions in the statute and would itself undermine the market certainty integral to success of the entire RFS program.

Fourth, as stated in the proposed rule, the carryover RIN provisions in the existing RFS regulations already represent a mechanism to help stabilize demand for cellulosic biofuel and cellulosic RINs in the event of a RIN surplus. In the event of a surplus of RINs in a current year, the fact that these RINs will still be of value in the

[211] For an example of this requested approach, see comments by the Coalition for Renewable Natural Gas (Docket Item No. EPA–HQ–OAR–2021–0427–0756).

[212] Several parties noted that EPA need not increase the required cellulosic volume for the subsequent year by the entire amount that cellulosic RIN generation and carryover RINs exceeded the required volume for that year, but that instead EPA could increase the required volume by a lesser amount to preserve some level of carryover RINs. Further, some parties explicitly stated that any increase to the required volume of cellulosic biofuel should occur 2 years after the observed RIN surplus. For example, if cellulosic RIN generation plus carryover RINs was greater than the required volume for 2023, EPA should increase the required volume for 2025 to meet the statutory requirements that the volumes be set 14 months in advance of the year to which they apply.

[213] For example, see comments from AFPM (EPA–HQ–OAR–2021–0427–0812) and Growth Energy (EPA–HQ–OAR–2021–0427–0796).

following year when RINs may be in short supply helps to stabilize the value of RINs, including D3 RINs, over time. We further address these comments in the RTC document.

EPA will continue to closely monitor the generation of all cellulosic RINs in future years and, if appropriate, will consider adjusting the cellulosic biofuel volume requirements.

*B. Non-Cellulosic Advanced Biofuel*

The volume targets established by Congress through 2022 anticipated volumes of advanced biofuel beyond what would be needed to satisfy the cellulosic standard. The statutory target for advanced biofuel in 2022 (21 billion gallons) allowed for up to five billion gallons of non-cellulosic advanced biofuel to be used towards the advanced biofuel volume target, and the applicable standards for 2022 similarly include five billion gallons of non-cellulosic advanced biofuel. As discussed in Sections III.B.2 and III.B.3, we developed candidate volumes for non-cellulosic advanced biofuel based on a consideration of supply-related factors and other relevant factors. This process included a consideration not only of production and import of non-cellulosic advanced biofuels, but also of the availability of qualifying feedstocks, a consideration of the supply of these fuels in the first quarter of 2023, and a desire to maximize benefits and limit potential negative consequences associated with the production of these fuels by focusing future growth on increases in feedstock production in North America. Based on this analysis of these factors, the candidate volumes for non-cellulosic biofuel represent significant growth relative to the volumes of these fuels supplied in 2022 (see Table III.C.2–1). We then analyzed these candidate volumes according to the other statutory factors.

To date, the vast majority of non-cellulosic advanced biofuel in the RFS program has been biodiesel and renewable diesel, with relatively small volumes of sugarcane ethanol and other advanced biofuels. Our assessment of the impact of non-cellulosic advanced biofuels on each of the statutory factors can be found in the RIA, that assessment is summarized briefly in this section. While the impacts of non-cellulosic advanced biofuels on the statutory factors can vary depending on the fuel type, production process, where the fuel is produced, and the feedstock used to produce the fuel, all advanced biofuels have the potential to provide significant GHG reductions as they are required to achieve at least 50 percent GHG reductions relative to the petroleum fuels they displace.[214] These potential GHG reductions suggest that non-cellulosic advanced biofuel volumes that meet or exceed those established by Congress for 2022 (5.0 billion RINs) may be appropriate.

Advanced biodiesel and renewable diesel together comprised 95 percent or more of the total supply of non-cellulosic advanced biofuel over the last several years, and together the two fuels are expected to continue to do so through 2025 due to the limited production and import of other types of non-cellulosic advanced biofuels (see RIA Chapters 6.2 through 6.4). We have therefore focused our attention on the impacts of these fuels in relation to the statutory factors in determining appropriate levels of non-cellulosic advanced biofuel for 2023–2025.[215]

As explained in Section III.B.2, we identified candidate volumes for non-cellulosic advanced biofuels based on the supply-related factors and other relevant factors. We also considered the supply of these fuels through March 2023 (the most recent month for which data were available at the time the analyses for this rule were completed). We concluded that domestic production capacity and availability of imports indicate that volumes of non-cellulosic advanced biofuel through 2025 could exceed the implied statutory target for 2022 (5 billion ethanol-equivalent gallons). Similarly, the feedstocks used to make advanced biodiesel and renewable diesel (such as soy oil, canola oil, and corn oil, as well as waste oils such as white grease, yellow grease, trap grease, poultry fat, and tallow) currently exist in sufficient quantities globally to supply increasing volumes. While there is potential for increasing growth in the production of some of these feedstocks, these feedstocks also have many existing uses and may require replacement with suitable substitutes if increasing quantities are used for biofuel production.

Beyond the supply-related statutory factors considered in determining the candidate volumes, our assessment of the impact of biodiesel and renewable diesel on the remaining statutory factors found that some of these factors would suggest that volumes higher than the candidate volumes are appropriate. For example, we observe also that higher implied volume requirements for non-cellulosic advanced biofuel may have energy security benefits and result in increases in domestic employment in the biofuels industry and increases in income for biofuel feedstock producers. Benefits to domestic employment are only likely to occur if increasing volumes of biodiesel and renewable diesel are produced domestically. Similarly, benefits to domestic feedstock producers are significantly more likely if these fuels are produced from domestic feedstocks. Our assessment of these factors therefore suggests it is appropriate to focus the volume requirements for these fuels on volumes that can be produced in the U.S. from North American feedstocks.[216]

Some of the statutory factors, however, suggest that lower volumes of non-cellulosic advanced biofuel would be appropriate. For instance, as described in RIA Chapter 10, the cost of biodiesel and renewable diesel is significantly higher than petroleum-based diesel fuel and is expected to remain so over the next several years. Even if biodiesel and renewable diesel blends are priced similarly to petroleum diesel at retail after accounting for the applicable federal and state incentives (including the RIN value), the higher relative costs of biodiesel and renewable diesel are still borne by society as a whole. Moreover, the fact that sufficient feedstocks exist to produce increasing quantities of advanced biodiesel and renewable diesel does not mean that those feedstocks are readily available or could be diverted to biofuel production without adverse consequences.

Further, we expect only limited quantities of fats, oils, and greases and distillers corn oil to be available for increased biodiesel and renewable diesel production in future years (see RIA Chapter 6.2). We expect that the primary feedstock available to biodiesel and renewable diesel producers through 2025 (beyond those currently used to produce biodiesel and renewable diesel) will be soybean oil and canola oil whose primary markets are for food, with lesser contributions from FOG and distillers corn oil. Increased demand for soybean oil and canola oil could incentivize increased production of these vegetable oils (through increased oilseed crushing), however if the use of soybean and canola oil for biofuel production increases faster than the projected

[214] CAA section 211(o)(1)(B)(i).

[215] We have also considered the potential for increasing volumes of renewable jet fuel. Given its similarity to renewable diesel, for purposes of projecting appropriate volume requirements for 2023–2025, in most cases we consider renewable jet fuel to be a component of renewable diesel.

[216] While biofuels produced from Canadian feedstocks do not increase employment in feedstock production, these feedstocks are often converted to biofuels in the U.S., which increases domestic employment in biofuel production. For a further discussion of our decision in this final rule to include canola oil imported from Canada in the feedstocks projected to be available to U.S. biofuel producers see RTC Section 4.2.

increase in production we project the result to be a diversion of feedstocks from food and other current uses and/or increasing imports of soybean oil, canola oil, or other products that can be used as a substitute. This would have a number of implications warranting caution on growing volumes further, including potentially reduced GHG benefits. Increased production of soybean oil and canola oil could also result in increasing soybean and canola production in the U.S. and abroad, and in turn could result in greater conversion of wetlands, adverse impacts on ecosystems and wildlife habitat, adverse impacts on water quality and supply, and increased prices for agricultural commodities and food prices.

Based on our analyses of all of the statutory factors, we believe that the candidate volumes derived in Section III.C.2 and shown in in Table III.C.2–1 would be reasonable and appropriate to require. These volumes reflect our consideration of the potential for GHG reductions that may result from their use, balanced with the projected increases in related feedstock production through 2025, the current high prices for vegetable oils that indicate high demand for vegetable oils relative to previous years, and the potential negative impacts associated with diverting some feedstock from existing uses to biofuel production. These numbers also reflect our assessment that non-cellulosic biofuels produced in the U.S. from domestic feedstocks (or imported Canadian canola oil) are likely to provide benefits (domestic jobs in biofuel and feedstock production, support for rural economic growth) and/or are less likely to have adverse impacts (*e.g.,* conversion of natural lands to crop production and high GHG emissions associated with land conversion) than imported fuels or fuels produced from imported feedstocks. The volumes we are finalizing are intended to reflect the projected increases in feedstock production in the U.S and Canada, particularly in 2025, while also providing continued support for biodiesel and renewable diesel producers.

While we have determined that it is reasonable to require the use of the candidate volumes of non-cellulosic advanced biofuel for 2023–2025, we are not establishing the advanced biofuel volume requirements for 2023–2025 at a level equal to the sum of the candidate volumes for cellulosic biofuel and non-cellulosic advanced biofuel. As discussed in greater detail in Section VI.D, we are establishing RFS volume requirements in this rule that reflect an implied conventional renewable fuel requirement of 15.0 billion gallons in each year.[217] Since we project that the quantity of conventional renewable fuel available in these years will be limited, significant volumes of non-ethanol biofuels will be needed to meet an implied conventional renewable fuel volume of 15.0 billion gallons. We project that the most likely source of non-ethanol biofuel will be biodiesel and renewable diesel that qualifies as BBD. Biodiesel and renewable diesel cannot be used to satisfy the projected shortfall in conventional renewable fuel if we already require the use of these fuels to meet the implied non-cellulosic advanced biofuel volume requirement. Therefore, the RFS volume requirements we are establishing in this rule reflect implied volumes for non-cellulosic advanced biofuel that are equal to the candidate volumes of these fuels less the volume projected to be needed to meet the shortfall in the implied conventional renewable fuel category (plus the 250 million gallon supplemental volume for 2023). The implied non-cellulosic advanced biofuel volumes for 2023–2025 we are finalizing in this rule are summarized in Table VI.B–1.

TABLE VI.C–1—NON-CELLULOSIC ADVANCED BIOFUEL

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Candidate Volume (Total supply) | 6,505 | 6,495 | 7,171 |
| Needed to meet the implied Conventional Volume | 1,155 | 1,045 | 1,221 |
| Needed to meet the Supplemental Volume Requirement | 250 | 0 | 0 |
| Available for the Advanced Standard | 5,100 | 5,450 | 5,950 |

### *C. Biomass-Based Diesel*

As described in the preceding section, we are establishing advanced biofuel volumes that represent increases of 100 million, 350 million, and 500 million ethanol-equivalent gallons per year in the implied non-cellulosic advanced biofuel volume requirement from 2023 through 2025. In concert, we are also finalizing BBD volume requirements by an energy-equivalent amount; 65 million physical gallons (100 million ethanol-equivalent gallons), 220 million physical gallons (350 million ethanol-equivalent gallons), and 310 million gallons (500 million ethanol-equivalent gallons) for 2023 through 2025 respectively. This approach 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. Our assessment of the impacts of BBD on the statutory factors is discussed further in the RIA.

As in recent years, we believe that excess volumes of BBD beyond the BBD volume requirements will be used to satisfy the advanced biofuel volume requirement within which the BBD volume requirement is nested. Historically, the BBD standard has not independently driven the use of BBD in the market. This is due to the nested nature of the standards and the competitiveness of BBD relative to other advanced biofuels. Instead, the advanced biofuel standard has driven the use of BBD in the market. Moreover, BBD can also be driven by the implied conventional renewable fuel volume requirement as an alternative to using increasing volumes of corn ethanol in higher level ethanol blends such as E15 and E85. We believe these trends will continue through 2025.

[217] In 2023, the implied volume for conventional renewable fuel would be 15.00 billion gallons, but the inclusion of the supplemental standard of 250 million gallons makes the implied conventional renewable fuel volume effectively 15.25 billion gallons. We sometimes refer to 15.25 billion gallons in 2023 as the effective volume requirement for conventional renewable fuel.

We also believe it is important to maintain space for other advanced biofuels to participate in the RFS program. Although the BBD industry has matured over the past decade, the production of advanced biofuels other than biodiesel and renewable diesel continues to be relatively low and uncertain. Maintaining this space for other advanced biofuels can in the long-term facilitate increased commercialization and use of other advanced biofuels, which may have superior environmental benefits, avoid concerns with food prices and supply, and have lower costs relative to BBD. Conversely, we do not think increasing the size of this space is necessary through 2025 given that only small quantities of these other advanced biofuels have been used in recent years relative to the space we have provided for them in those years.

*D. Conventional Renewable Fuel*

Although Congress had intended cellulosic biofuel to become the most widely used renewable fuel by 2022, instead, conventional renewable fuel has remained as the majority of renewable fuel supply since the RFS program began in 2005. The favorable economics of blending corn ethanol at 10 percent into gasoline caused it to quickly saturate the gasoline supply shortly after the RFS program began and it has remained in nearly every gallon of gasoline used for transportation in the United States ever since.

The implied statutory volume target for conventional renewable fuel rose annually between 2009 and 2015 until it reached 15 billion gallons where it remained through 2022. EPA has used 15 billion gallons of conventional renewable fuel in calculating the applicable percentage standards for several recent years, most recently for 2022.[218] [219]

As discussed in Section III.B.5, constraints on ethanol consumption have made reaching 15 billion gallons with ethanol alone infeasible, even with the incentives provided by the RFS program and after accounting for the projected increase in the availability of higher-level ethanol blends such as E15 and E85. We expect these constraints to continue through 2025. The difficulty in reaching 15 billion gallons with ethanol is compounded by the fact that gasoline demand for 2023–2025 is not projected to recover to pre-pandemic levels, and moreover is expected to be lower by 2025 than it was in 2022. These constraints are reflected in the candidate volumes for conventional renewable fuel, which ranged from approximately 13.8 to 14.0 billion gallons from 2023–2025 (see Table III.C.3–1).

Nevertheless, we do not believe that constraints on ethanol consumption should be the single determining factor in the appropriate level of conventional renewable fuel to establish for 2023–2025. The implied volume requirement for conventional renewable fuel is not a requirement for ethanol, nor even for conventional renewable fuel. Instead, conventional renewable fuel is that portion of total renewable fuel which is not required to be advanced biofuel. The implied volume requirement for conventional renewable fuel can also be satisfied by non-ethanol advanced biofuel, such as conventional biodiesel and renewable diesel or advanced biodiesel and renewable diesel beyond what is required by the advanced biofuel volume requirement.

Higher-level ethanol blends such as E15 and E85 are one avenue through which higher volumes of renewable fuels can be used in the transportation sector to reduce GHG emissions and improve energy security over time, and the incentives created by the implied conventional renewable fuel volume requirement contribute to the economic attractiveness of these fuels. Moreover, sustained and predictable support of higher-level ethanol blends through the level of the implied conventional renewable fuel volume requirement helps provide some longer-term incentive for the market to invest in the necessary infrastructure. As a result, we do not believe it would be appropriate to reduce the implied conventional renewable fuel volume requirement below 15 billion gallons at this time.

Our analysis of several of the statutory factors highlighted, in our view, the importance of ongoing support for corn ethanol generally and for an implied conventional renewable fuel volume requirement that helps to incentivize the domestic consumption of corn ethanol. These include the economic advantages to the agricultural sector, most notably for corn farmers, as well as employment at ethanol production facilities and related ethanol blending and distribution activities. The rural economies surrounding these industries also benefit from strong demand for ethanol. The consumption of ethanol, most notably that produced domestically, reduces our reliance on foreign sources of petroleum and increases the energy security status of the U.S. as discussed in Section IV.B.

Although most corn ethanol production occurs in facilities that commenced construction prior to December 19, 2007, and is ''grandfathered'' under the provisions of 40 CFR 80.1403, and thus is not required to achieve a 20 percent reduction in GHGs in comparison to gasoline,[220] nevertheless, based on our current assessment of GHG impacts, on average corn ethanol provides some GHG reduction in comparison to gasoline. Greater volumes of ethanol consumed thus correspond to greater GHG reductions than would be the case if gasoline was consumed instead of ethanol.

The volumes we are finalizing in this rule reflect an implied conventional renewable fuel volume of 15.0 billion gallons each year from 2023–2025.[221] These volumes are consistent with the statutory intent of the RFS program and provide ongoing incentive for the use of higher-level ethanol blends. As discussed in the preceding paragraphs, greater use of higher-level ethanol blends is expected to result in benefits to rural economic development and energy security and is projected to reduce GHG emissions from the transportation sector. While we recognize that ethanol consumption is highly unlikely to reach 15.0 billion gallons in any year through 2025 there are sufficient volumes of non-ethanol renewable fuels to enable the total renewable fuel volume requirements to be met.

In our proposed rule, the RFS volumes reflected an implied conventional renewable fuel volume of 15.25 billion gallons for 2024 and 2025. In comments on our proposed rule multiple stakeholders stated that any increase in the implied volume requirement for conventional renewable fuel above 15 billion gallons was inconsistent with Congress' intention that all increases in renewable fuel between 2015 and 2022 be in advanced biofuel, with conventional renewable fuel static at 15 billion gallons. We

[218] EPA did not use 15 billion gallons of conventional renewable fuel for 2016, but instead used the general waiver authority to reduce that implied volume requirement below 15 billion gallons. The U.S. Courts of Appeals for the D.C. Circuit ruled in *ACE* that EPA had improperly used the general waiver authority, and remanded that rule back to EPA for reconsideration. As discussed in Section V, EPA is responding to this remand through the application of a supplemental standard in 2023 that, combined with an identical supplemental standard in 2022, rectifies our inappropriate use of the general waiver authority for 2016. The effective implied conventional biofuel volume for 2023 of 15.25 billion gallons is thus a result of the 2023 supplemental standard.

[219] 87 FR 39600 (July 1, 2022).

[220] CAA section 211(o)(2)(A)(i).

[221] In 2023, the implied volume for conventional renewable fuel is 15.00 billion gallons, but the inclusion of the supplemental standard of 250 million gallons makes the conventional renewable fuel volume effectively 15.25 billion gallons.

continue to believe that EPA has authority to establish RFS volumes that reflect an implied conventional renewable fuel volume that is greater than 15.0 billion gallons if these volumes are supported by our analysis of the statutory factors. However, after reviewing the public comments and available data we have decided to finalize RFS volumes that reflect an implied conventional renewable fuel volume of 15.0 billion gallons each year from 2023–2025. We believe these volumes are supported by our analysis of the statutory factors, are consistent with the statutory intent of the RFS program, and appropriately balance a desire to provide continued incentives for higher level ethanol blends and a desire to incentivize increasing production and use of advanced biofuels.

Table VI.B–1. shows the types of biofuel we project will be supplied to meet the implied conventional renewable fuel volumes, including both conventional ethanol and non-cellulosic advanced biofuels beyond those needed to satisfy the advanced biofuel volume requirements.

TABLE VI.D–1—MEETING THE CANDIDATE VOLUME FOR CONVENTIONAL RENEWABLE FUEL

[Million RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Conventional ethanol | 13,845 | 13,955 | 13,779 |
| Non-cellulosic advanced biofuel | 1,405 | 1,045 | 1,221 |
| Total | [a] 15,250 | 15,000 | 15,000 |

[a] Includes the additional 250 million RINs needed to satisfy the supplemental volume requirement addressing the remand of the 2016 standards.

Based on our assessment of available supply, we do not believe that there would be a need for conventional biodiesel or renewable diesel to be imported in order to help meet an effective conventional renewable fuel candidate volume of 15.25 billion gallons in 2023 (after accounting for the supplemental standard) and 15.0 billion gallons in 2024 and 2025. A review of the recent RIN generation data suggests that conventional biodiesel and renewable diesel are unlikely to be supplied to the U.S. market if sufficient volumes of advanced biodiesel and renewable diesel are available. Nevertheless, such imports remain a potential source in the event that the market did not respond to the candidate volumes in the way that we have projected it would. As discussed in Section III.B.4.b, total production capacity from grandfathered biodiesel and renewable diesel facilities is approximately 2.5 billion gallons.

*E. Summary of Final Volume Requirements*

For the reasons described above, we are establishing RFS volume requirements based the four component categories discussed above. The volumes for each of the component categories (sometimes referred to as implied volume requirements) are summarized in Table VI.E–1. Also shown is the supplemental volume requirement addressing the 2016 remand, discussed more fully in Section V.

TABLE VI.E–1—FINAL VOLUME REQUIREMENTS FOR COMPONENT CATEGORIES

[Billion RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel | 0.84 | 1.09 | 1.38 |
| Biomass-based diesel [a] | 2.82 | 3.04 | 3.35 |
| Non-cellulosic advanced biofuel | 5.10 | 5.45 | 5.95 |
| Conventional renewable fuel | 15.00 | 15.00 | 15.00 |
| Supplemental volume requirement | 0.25 | 0 | 0 |

[a] BBD volumes are given in billion gallons.

These final volumes are similar to, but higher than the volumes in the proposed rule (after accounting for the fact that we are not finalizing the proposed eRIN provisions in this rule). Specifically, the cellulosic biofuel volumes are higher for all three years. The volumes for non-cellulosic advanced biofuels in this final rule are equal to the volumes from the proposed rule in 2023, and 250 million and 650 million ethanol-equivalent gallons higher in 2024 and 2025 respectively. Finally, the volumes for conventional biofuel in this final rule are equal to the volumes in the proposed rule for 2023, and 250 million gallons lower for 2024 and 2025. The volumes for each of the four component categories shown in the table above can be combined to produce volume requirements for the four statutory categories on which the applicable percentage standards are based. The results are shown below.

TABLE VI.E–2—FINAL VOLUME REQUIREMENTS FOR STATUTORY CATEGORIES

[Billion RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel | 0.84 | 1.09 | 1.38 |
| Biomass-based diesel [a] | 2.82 | 3.04 | 3.35 |
| Advanced biofuel | 5.94 | 6.54 | 7.33 |
| Total renewable fuel | 20.94 | 21.54 | 22.33 |

TABLE VI.E–2—FINAL VOLUME REQUIREMENTS FOR STATUTORY CATEGORIES—Continued

[Billion RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Supplemental volume requirement | 0.25 | 0 | 0 |

[a] BBD volumes are given in billion gallons.

We believe that these volume requirements will preserve and continue the gains made through biofuels in previous years when the statute specified applicable volume targets. In particular, these volume requirements will help ensure that the transportation sector will realize additional reductions in GHGs and that the U.S. will experience greater energy independence and energy security. The volume requirements will also promote ongoing development within the biofuels and agriculture industries as well as the economies of the rural areas in which biofuels production facilities and feedstock production reside.

As discussed in Section II, our volume requirements for 2023 and the associated percentage standards will not be in place prior to the beginning of 2023, and we are establishing the 2024 applicable volumes after the statutory deadline. For the reasons described in Section II, the standards are nonetheless appropriate.

## VII. Percentage Standards for 2023–2025

EPA has historically implemented the nationally applicable volume requirements by establishing percentage standards that apply to obligated parties, consistent with the statutory requirements at CAA section 211(o)(3)(B). The statute gives EPA discretion as to how applicable volume requirements should be implemented for years after 2022. The CAA requires EPA to promulgate regulations that, regardless of the date of promulgation, contain compliance provisions applicable to refineries, blenders, distributors, and importers that ensure that the volumes in CAA section 211(o)(2)(B), which includes set volumes, are met.[222] Further, under the statutory requirement that we review implementation of the program in prior years as part of our determination of the appropriate volume requirements for years after 2022,[223] we considered the past effectiveness of the use of percentage standards as the implementation mechanism for volume requirements. We determined that this mechanism continues to be effective and reasonable, and obligated parties are, at this point, very familiar with this implementation mechanism. We were also unable to identify any straightforward and easily implementable alternative mechanisms, nor were any suggested in comments on the proposal. Therefore, we are continuing to use percentage standards as the implementing mechanism for years after 2022.

The obligated parties to which the percentage standards apply are producers and importers of gasoline and diesel, as defined by 40 CFR 80.1406(a).[224] Each obligated party multiplies the percentage standards by the sum of all non-renewable gasoline and diesel they produce or import to determine their Renewable Volume Obligations (RVOs).[225] The RVOs are the number of RINs that the obligated party is responsible for procuring to demonstrate compliance with the applicable standards for that year. Since there are four separate standards under the RFS program, there are likewise four separate RVOs applicable to each obligated party for each year.[226] The renewable fuel volumes used to determine the 2023, 2024, and 2025 percentage standards are described in Section VI.E and are shown in Table VII–1.

TABLE VII–1—VOLUMES FOR USE IN DETERMINING THE APPLICABLE PERCENTAGE STANDARDS

[Billion RINs]

| | 2023 | 2024 | 2025 |
|---|---|---|---|
| Cellulosic biofuel | 0.84 | 1.09 | 1.38 |
| Biomass-based diesel [a] | 2.82 | 3.04 | 3.35 |
| Advanced biofuel | 5.94 | 6.54 | 7.33 |
| Renewable fuel | 20.94 | 21.54 | 22.33 |
| Supplemental standard | 0.25 | n/a | n/a |

[a] The BBD volumes are in physical gallons (rather than RINs).

As described in Section II.D, EPA is permitted to establish applicable percentage standards for multiple future years after 2022 in a single action for as many years as it establishes volume requirements.

### *A. Calculation of Percentage Standards*

The formulas used to calculate the percentage standards applicable to obligated parties are provided in 40 CFR 80.1405(c). We are continuing to use the percentage standard mechanism to implement the volume requirements for years after 2022.

In addition to the required volumes of renewable fuel, the formulas also require estimates of the volumes of non-renewable gasoline and diesel, for both highway and nonroad uses, that are projected to be used in the year in which the standards will apply. In previous annual standard-setting rules,

[222] CAA section 211(o)(2)(A)(i) and (iii).

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

[224] Note that in this action, we are moving the definition of ''obligated party'' without modification from 40 CFR 80.1406(a) to 40 CFR 80.2. This is part of an effort to consolidate all defined terms into a single regulatory section. In Section IX.K, we further discuss the consolidation of all definitions in 40 CFR part 80, subpart M, into the definitions section at 40 CFR 80.2. EPA is not reopening the definition of obligated party.

[225] 40 CFR 80.1407.

[226] As discussed in Section V, we are finalizing a supplemental standard for 2023 to address the remand of the 2016 standards under *ACE*. That supplemental standard is in addition to the four standards required under the statute, though as described in Section V, compliance demonstrations for total renewable fuel and the supplemental standard will be combined in annual compliance reports submitted under 40 CFR 80.1451.

the statute required the Energy Information Administration (EIA) to provide to EPA projected volumes of transportation fuel to be sold or introduced into commerce in the United States for the following calendar year by October 31 of each year.[227] However, the last year to which this statutory requirement applied was 2021 and therefore it does not apply to compliance years after 2022. Moreover, historically the transportation fuel projections EIA provided to EPA consisted of the gasoline and diesel volume projections from EIA's Short Term Energy Outlook (STEO).[228] The STEO only provides volume projections for one future calendar year, which was sufficient to inform past annual standard-setting rulemakings as they never established applicable percentage standards for more than one future calendar year. In contrast, this rulemaking establishes volume requirements and associated percentage standards for three future calendar years. Therefore, we cannot use the STEO as a source for projections of gasoline and diesel for this action and are instead using EIA's 2023 Annual Energy Outlook (AEO) for the purposes of calculating the percentage standards in this action.[229]

Before using EIA's projections of gasoline and diesel, however, several adjustments need to be made. First, the projected gasoline and diesel volumes in AEO 2023 include projections of renewable fuels used in transportation fuel (*e.g.,* ethanol, biodiesel, and renewable diesel). Since renewable fuels are not subject to the percentage standards, the volumes of renewable fuel are subtracted out of the EIA projections of gasoline and diesel. Second, the projected diesel volumes in AEO 2023 also include projections of diesel used in ocean-going vessels. Since fuel used in ocean-going vessels is explicitly excluded from the definition of transportation fuel in 40 CFR 80.2—and therefore is not an obligated fuel and does not incur an RVO under the RFS program—the volumes of these fuels are subtracted out of the EIA projections of diesel. Third, the projected gasoline, diesel, and renewable fuel volumes in AEO 2023 include projections of these fuels used in Alaska. Since Alaska is not part of the RFS covered area—and therefore fuel used in this state is excluded from the RFS program—the volumes of gasoline, diesel, and renewable fuel used in Alaska are subtracted out of EIA's nationwide projections of these fuels.[230] Finally, as discussed in RIA Chapter 1.11, EPA has determined that it is necessary to make an adjustment to the projections of gasoline and diesel provided by EIA in AEO 2023 to accurately reflect the gasoline and diesel volumes ultimately used by obligated parties in their RVO calculations. The table below provides the precise projections from AEO 2023 used to calculate the percentage standards for 2023–2025.

TABLE VII.A–1—AEO 2023 VOLUMES USED FOR THE CALCULATION OF PERCENTAGE STANDARDS FOR 2023–2025

| Fuel category | Table | Line |
|---|---|---|
| Gasoline | Table 11 [a] | Product Supplied/by Fuel/Motor Gasoline. |
| Renewables blended into gasoline | Table 2 | Energy Use & Related Statistics/Ethanol (denatured) Consumed in Motor Gasoline. |
| | Table 11 | Biofuels/Other Biomass-derived Liquids. |
| Diesel | Table 11 | Product Supplied/by Fuel/Distillate fuel oil/of which: Diesel. |
| Renewables blended into diesel | Table 11 | Biofuels/Biodiesel. |
| | | Biofuels/Renewable Diesel. |
| Diesel used in ocean-going vessels | Table 49 | International Shipping/Distillate Fuel Oil (diesel). |

[a] In the proposal for this action, we used the gasoline demand forecasts from Table 2 of AEO 2022 to calculate the proposed percentage standards. We intended to use Table 2 of AEO 2023 to calculate the percentage standards in this action as well; however, EIA informed EPA that 2023 gasoline demand forecast in Table 2 is not benchmarked to STEO whereas it is in Table 11 and directed EPA to use the values in Table 11 instead.

In order to convert projections provided by EIA in energy units into the volumes needed for the calculation of percentage standards, we used the conversion factors provided in AEO 2023 Table 68.[231]

### *B. Treatment of Small Refinery Volumes*

In CAA section 211(o)(9), Congress provided for qualifying small refineries to be temporarily exempt from RFS compliance through December 31, 2010. Congress also provided that small refineries could receive an extension of the exemption beyond 2010 based either on the results of a required Department of Energy (DOE) study or in response to individual petitions demonstrating that the small refinery suffered ''disproportionate economic hardship.'' CAA section 211(o)(9)(A)(ii)(II) and (B)(i).

The annual percentage standards herein are based on our projection that no gasoline or diesel produced by small refineries will be exempt from RFS requirements pursuant to CAA section 211(o)(9) for 2023–2025. In April and June 2022, EPA denied 105 pending SRE petitions for years spanning 2016 through 2020, finding that, consistent with the holding of the U.S. Court of Appeals for the Tenth Circuit in *Renewable Fuels Association* v. *EPA,* SREs can only be granted under CAA section 211(o)(9) if a small refinery demonstrates that it would suffer disproportionate economic hardship caused by compliance with the RFS program requirements and not due, even in part, to other factors.[232] In applying this new statutory interpretation, we found that that none of the small refinery petitioners suffered disproportionate economic hardship caused by their compliance with the RFS because all obligated parties, including small refineries, are able to pass through the costs of their RFS compliance (*i.e.,* RIN costs) to their customers in the form of higher sales prices for gasoline and diesel. Accordingly, we denied all SRE petitions pending at that time.[233]

[227] CAA section 211(o)(3)(A).

[228] See, for example, ''EIA letter to EPA with 2020 volume projections 10–9–2019,'' available in the docket.

[229] Available at *https://www.eia.gov/outlooks/aeo.*

[230] State-specific projections of gasoline, diesel, and renewable fuel usage are not provided in AEO 2023. Instead, we use data from EIA's State Energy Data System (SEDS) to estimate the portion of these fuels used in Alaska, available at *https://www.eia.gov/state/seds/seds-data-fuel.php.*

[231] Available at *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=20-AEO2023&cases=ref2023&sourcekey=0.*

[232] *Renewable Fuels Assn* v. *EPA,* 948 F.3d 1206, 1253–54 (10th Cir. 2020); see generally, April 2022 SRE Denial Action and June 2022 SRE Denial Action.

[233] For a fuller discussion of EPA's revised statutory interpretation and analysis of the costs of RFS compliance, see the April and June 2022 Denial Actions at Section IV.D.

Absent new arguments and supporting data to the contrary, we anticipate that the CAA interpretation and analysis presented in the April and June 2022 SRE Denial Actions will also apply to these future-year SRE petitions. Consequently, at this time, we anticipate that no SREs will be granted for these future years, including the 2023–2025 compliance years covered by this action. Therefore, we project that the exempt volumes from SREs to be included in the calculation specified by 40 CFR 80.1405(c) for 2023, 2024, and 2025 will be zero, and all small refineries will be required to comply with their proportional RFS obligations.[234] Nevertheless, because the obligations are calculated by applying the percentage standards to gasoline and diesel production volume, the RFS volume obligations on small refineries are proportionally smaller than on larger obligated parties. Even were EPA to grant an SRE in the future for 2023–2025, we do not plan to revise the percentage standards to account for such an exemption.[235]

*C. Percentage Standards*

The formulas in 40 CFR 80.1405 for the calculation of the percentage standards require the specification of a total of 14 variables comprising the renewable fuel volume requirements, projected gasoline and diesel demand for all states and territories where the RFS program applies, renewable fuels projected by EIA to be included in the gasoline and diesel demand, and projected gasoline and diesel volumes from exempt small refineries. The values of all the variables used for this rule are shown in Table VII.C–1 for 2023, 2024, and 2025.[236]

TABLE VII.C–1—VOLUMES FOR TERMS IN CALCULATION OF THE PERCENTAGE STANDARDS

[Billion RINs]

| Term | Description | 2023 | 2023 Supplemental | 2024 | 2025 |
|---|---|---|---|---|---|
| $RFV_{CB}$ | Required volume of cellulosic biofuel | 0.84 | 0.00 | 1.09 | 1.38 |
| $RFV_{BBD}$ | Required volume of biomass-based diesel [a] | 2.82 | 0.00 | 3.04 | 3.35 |
| $RFV_{AB}$ | Required volume of advanced biofuel | 5.94 | 0.00 | 6.54 | 7.33 |
| $RFV_{RF}$ | Required volume of renewable fuel | 20.94 | 0.25 | 21.54 | 22.33 |
| G | Projected volume of gasoline | 138.62 | 138.62 | 139.57 | 137.49 |
| D | Projected volume of diesel | 55.44 | 55.44 | 52.59 | 52.04 |
| RG | Projected volume of renewables in gasoline | 14.48 | 14.48 | 14.89 | 14.77 |
| RD | Projected volume of renewables in diesel | 4.48 | 4.48 | 4.93 | 4.73 |
| GS | Projected volume of gasoline for opt-in areas | 0.00 | 0.00 | 0.00 | 0.00 |
| RGS | Projected volume of renewables in gasoline for opt-in areas | 0.00 | 0.00 | 0.00 | 0.00 |
| DS | Projected volume of diesel for opt-in areas | 0.00 | 0.00 | 0.00 | 0.00 |
| RDS | Projected volume of renewables in diesel for opt-in areas | 0.00 | 0.00 | 0.00 | 0.00 |
| GE | Projected volume of gasoline for exempt small refineries | 0.00 | 0.00 | 0.00 | 0.00 |
| DE | Projected volume of diesel for exempt small refineries | 0.00 | 0.00 | 0.00 | 0.00 |

[a] The BBD volume used in the formula represents physical gallons. The formula contains a 1.6 multiplier to convert this physical volume to ethanol-equivalent volume, consistent with the change to the BBD conversion factor discussed in Section X.D.

Using the volumes shown in Table VII.C–1, we have calculated the percentage standards for 2023, 2024, and 2025 as shown in Table VII.C–2.

TABLE VII.C–2—PERCENTAGE STANDARDS

| | 2023 (%) | 2024 (%) | 2025 (%) |
|---|---|---|---|
| Cellulosic biofuel | 0.48 | 0.63 | 0.81 |
| Biomass-based diesel | 2.58 | 2.82 | 3.15 |
| Advanced biofuel | 3.39 | 3.79 | 4.31 |
| Renewable fuel | 11.96 | 12.50 | 13.13 |
| Supplemental standard | 0.14 | n/a | n/a |

The percentage standards shown in Table VII.C–2 are included in the regulations at 40 CFR 80.1405(a) and apply to producers and importers of gasoline and diesel.

## VIII. Administrative Actions

### *A. Assessment of the Domestic Aggregate Compliance Approach*

[234] We are not prejudging any SRE petitions in this action; however, absent a sufficient demonstration that a small refinery experiences DEH caused by compliance with the RFS program, we do not anticipate granting SREs in the future.

[235] See Renewable Fuel Standard (RFS) Program: RFS Annual Rules, Response to Comments, EPA–420–R–22–009, June 2022, at 145 for further discussion on our approach to this projection in the event we grant a future SRE.

[236] See ''Calculation of Final 2023–2025 Percentage Standards,'' available in the docket for this action.

The RFS regulations specify an "aggregate compliance" approach for demonstrating that planted crops and crop residue from the U.S. comply with the "renewable biomass" requirements that address lands from which qualifying feedstocks may be harvested.[237] In the 2010 RFS2 rulemaking, EPA established a baseline number of acres for U.S. agricultural land in 2007 (the year of EISA's enactment) and determined that as long as this baseline number of acres is not exceeded, it is unlikely, based on our assessment of historical trends and economic considerations, that new land outside of the 2007 baseline is being devoted to crop production. The regulations specify, therefore, that renewable fuel producers using planted crops or crop residue from the U.S. as feedstock in renewable fuel production need not undertake individual recordkeeping and reporting related to documenting that their feedstocks come from qualifying lands, unless EPA determines through one of its annual evaluations that the 2007 baseline acreage of 402 million acres agricultural land has been exceeded. The regulations promulgated in 2010 require EPA to make an annual finding concerning whether the 2007 baseline amount of U.S. agricultural land has been exceeded in a given year. If the baseline is found to have been exceeded, then producers using U.S. planted crops and crop residue as feedstocks for renewable fuel production would be required to comply with individual recordkeeping and reporting requirements to verify that their feedstocks are renewable biomass.

Based on data provided by the USDA Farm Service Agency (FSA) and Natural Resources Conservation Service (NRCS), we have estimated that U.S. agricultural land reached approximately 384.7 million acres in 2022 and thus did not exceed the 2007 baseline acreage of 402 million acres.[238] [239] We will continue to monitor total agricultural land annually to determine if national agricultural land acreage increases above this 2007 national aggregate baseline, as specified in the RFS2 Rule.[240]

*B. Assessment of the Canadian Aggregate Compliance Approach*

The RFS regulations specify a petition process through which EPA may approve the use of an aggregate compliance approach for planted crops and crop residue from foreign countries.[241] On September 29, 2011, EPA approved such a petition from the Government of Canada.[242] The total agricultural land in Canada in 2022 is estimated at 116.4 million acres. This total agricultural land area includes 94.9 million acres of cropland and summer fallow, 11.7 million acres of pastureland, and 9.8 million acres of agricultural land under conservation practices. This acreage estimate is based on the same methodology used to set the 2007 baseline acreage for Canadian agricultural land in EPA's response to Canada's petition. This 2022 acreage does not exceed the 2007 baseline acreage of 122.1 million acres.[243] We will continue to monitor total agricultural land annually to determine if Canadian agricultural land acreage increases above its 2007 aggregate baseline, as specified in the RFS2 Rule.[244]

## IX. Biogas Regulatory Reform

We are finalizing biogas regulatory reform provisions to allow for the use of biogas as a biointermediate and RNG as a feedstock to produce biogas-derived renewable fuels other than renewable CNG/LNG.[245] The biogas regulatory reform provisions will also substantially help improve oversight of the program and mitigate against the potential for parties to double-count biogas and RNG given the program's expansion, thereby helping to ensure that only valid RINs are generated for biogas-derived renewable fuels. EPA received comment from many stakeholders on our proposed biogas regulatory reform provisions; we summarize and respond to all comments received in RTC Section 10.

*A. Background*

1. Statutory Authority

Congress established the RFS2 program in the 2007 Energy Independence and Security Act (EISA). Among other revisions to the prior RFS1 program that had been established by EPAct 2005, EISA defined 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." [246] This definition has two relevant key components, both of which are necessary to generate RINs: (1) The fuel must be produced from renewable biomass, and (2) The fuel must be used to replace or reduce fossil fuel used as transportation fuel. EISA also provided a definition of "renewable biomass," enumerating the seven categories of feedstocks that can be used to produce qualifying renewable fuel under RFS2.[247] This statutory definition of renewable biomass includes, among other things, separated yard waste, separated food waste, animal waste material, and crop residue, any of which are commonly used to produce biogas through anaerobic digestion.[248] EISA, as reflected in CAA section 211(o)(2)(A)(i),

[237] 40 CFR 80.1454(g). EPA established the "aggregate compliance" approach in the 2010 RFS2 rule and has applied it for the U.S. in annual RFS rulemakings since then. See 75 FR 14701–04. In this final rule, we have not reexamined or reopened this policy, including the regulations at 40 CFR 80.1454(g) and 80.1457. Similarly, as further explained below, we have applied this approach for Canada since our approval of Canada's petition to use aggregate compliance in 2011. In this final rule, we have also not reexamined or reopened our decision on that petition. Any comments we received on these issues are beyond the scope of this rulemaking.

[238] For additional analysis and the underlying USDA data, see "Assessment of Domestic Aggregate Compliance Approach 2022," available in the docket for this action.

[239] USDA also provided EPA with 2021 data from the discontinued Grassland Reserve Program (GRP) and Wetlands Reserve Program (WRP). Given this data, EPA estimated the total U.S. agricultural land both including and omitting the GRP and WRP acreage. In 2021, combined land under GRP and WRP totaled 2,993,177 acres. Subtracting the GRP and WRP acreage in addition to the Agriculture Conservation Easement Program acreage yields an estimate of 379.6 million total acres of U.S. agricultural land in 2021. Just subtracting the Agriculture Conservation Easement Program leads to an estimate of 382.6 million total acres of U.S. agricultural land in 2021.

[240] 75 FR 14701.

[241] 40 CFR 80.1457.

[242] See "EPA Decision on Canadian Aggregate Compliance Approach Petition" (Docket Item No. EPA–HQ–OAR–2011–0199–0015).

[243] The data used to make this calculation can be found in "Assessment of Canadian Aggregate Compliance Approach 2022," available in the docket for this action.

[244] 75 FR 14701.

[245] For purposes of this section of the preamble, by renewable natural gas or RNG, we mean a product derived from biogas that is produced from renewable biomass and that meets the natural gas commercial distribution pipeline specification for the pipeline that it is injected into. We refer to biogas that is produced from renewable biomass and that has undergone treatment to remove impurities and inert gases to a level suitable for its use to produce renewable CNG/LNG, but is not injected onto the natural gas commercial pipeline system as treated biogas. Generally, the primary difference between RNG and treated biogas is that RNG is injected onto the natural gas commercial distribution system and treated biogas is distributed via a closed, private distribution system. Biomethane is the methane component of biogas, treated biogas, and RNG that is derived from renewable biomass. Under the previous and new regulations, RIN generation is based on the energy, in BTUs, from biomethane (exclusive of impurities, inert gases often found with biomethane in biogas) that is demonstrated to be used as transportation fuel.

[246] CAA section 211(o)(1)(J).

[247] CAA section 211(o)(1)(I).

[248] Biogas was explicitly included in EPAct 2005 as a renewable fuel and therefore was included in the RFS1 program that applied from 2006–2009. In the 2010 rulemaking that established the RFS2 program based on changes to CAA section 211(o) enacted through EISA in 2007, we concluded that biogas was a qualifying renewable fuel if it is produced from "renewable biomass." See 75 FR 14685–14686 (March 26, 2010).

also directs EPA to ''promulgate'' and ''revise'' ''regulations . . . to ensure that transportation fuel sold or introduce into commerce . . . contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel.'' The regulations EPA is promulgating as part of biogas regulatory reform in this action are necessary to ensure that biogas and RNG used to produce fuels that are in turn used to satisfy the statutory volume requirements actually qualify as renewable fuel, *i.e.,* are actually produced from renewable biomass and used as transportation fuel.

Additionally, the statutory definition of advanced biofuel at CAA section 211(o)(1)(B)(ii)(V) explicitly identifies biogas as a valid form of advanced biofuel. However, the statute does not specify how biogas that is produced from renewable biomass must be used in order to qualify as renewable fuel (*i.e.,* in the form of CNG or LNG, or in some other form). Biogas can be used as a feedstock to create renewable CNG/LNG, through clean-up and compression, or to produce other fuels, such as hydrogen or Fischer-Tropsch fuels. In this action, we are putting in place provisions that will allow for biogas to be used as a biointermediate feedstock to produce renewable fuels other than renewable CNG/LNG. As explained in our action establishing a biointermediates program, biointermediates are simply renewable biomass feedstocks that are partially processed at one facility before being transported to a different facility to complete processing into renewable fuel.[249] While EPA had historically not permitted feedstocks to be processed at multiple facilities due to implementation and oversight concerns, we recently expanded the program to allow processing at two different facilities under certain circumstances. In establishing the initial biointermediates program, EPA did not include biogas as a biointermediate because we acknowledged that the regulations we were promulgating at that time would not be appropriate for the more complex circumstances of biogas. The biogas regulatory reform regulations we are promulgating in this action provide the compliance and oversight mechanisms necessary to allow biogas to be processed into a biointermediate at one facility and then further processed into renewable fuel at a second facility while remaining consistent with the statutory requirements and applicable RFS pathway.[250]

2. Regulatory History

In the 2010 RFS2 rule, EPA included regulatory provisions for the generation of advanced biofuel (D code 5, or D5) RINs from biogas used as transportation fuel. The RFS2 regulations listed biogas as the fuel and included provisions for how a party demonstrated that biogas was used as transportation fuel. However, biogas as the term is defined in EPA's regulations and often used by industry is not actually a product that can be used as a transportation fuel. Biogas must undergo significant treatment to be used as a fuel especially in the form CNG/LNG because impurities found in biogas could cause substantial operability issues thereby harming CNG/LNG engines. Additionally, after promulgating the pathway for D5 RINs EPA received several pathway petitions requesting that EPA allow for the generation of cellulosic biofuel (D code 3, or D3) RINs for biogas produced from cellulosic feedstocks.

In 2014, EPA finalized the RFS ''Pathways II'' rule, which among other things added specific RIN-generating pathways for renewable CNG, renewable LNG, and renewable electricity to rows Q and T to Table 1 of 40 CFR 80.1426 (''Pathway Q'' and ''Pathway T'', respectively).[251] Pathway Q allowed for D3 RIN generation for renewable CNG/LNG produced from biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated municipal solid waste (MSW) digesters, as well as biogas from the cellulosic components of biomass processed in other waste digesters. Pathway T allowed for D5 RIN generation for renewable CNG/LNG from biogas from waste digesters, which encompasses non-cellulosic biogas. These two pathways were structured so that biogas from approved sources would be the feedstock and renewable CNG/LNG would be the finished fuel for RIN generation purposes.

The Pathways II rule also established a then new set of regulatory provisions that detail the criteria necessary for biogas to be demonstrated to be renewable fuel and thus eligible to generate RINs. The regulations address two scenarios under which renewable CNG/LNG is produced and used for transportation. First, for renewable CNG/LNG produced from biogas that is only distributed via a closed, private, non-commercial system, the renewable CNG/LNG must be produced from renewable biomass under an EPA-approved pathway and demonstrated to be sold and used as transportation fuel.[252] Under this scenario, only renewable CNG/LNG that was produced and distributed as transportation fuel in a closed, private non-commercial system could generate RINs. Typically, parties that generate RINs under the closed scenario are directly supplying renewable CNG/LNG to a CNG/LNG fleet in close proximity to where the biogas is produced and collected and in many cases the party that generates the RIN is the same party that owns/operates the CNG/LNG fleet.

The second scenario under which RINs could be generated for renewable CNG/LNG addresses when renewable CNG/LNG is introduced into a commercial distribution system (*e.g.,* natural gas commercial pipeline system). In addition to demonstrating that the CNG/LNG is produced from renewable biomass under an EPA-approved pathways and sold and used as transportation fuel, potential RIN generators under this scenario must also demonstrate that the RNG was loaded onto and withdrawn from a physically-connected natural gas commercial distribution system, that the amount of CNG/LNG sold as transportation fuel corresponds with the amount of RNG placed onto the natural gas commercial distribution system, and that no other party relied on the RNG for the creation of RINs.[253] These additional requirements for CNG/LNG transmitted via a natural gas commercial distribution system were designed to ensure that the amount of renewable CNG/LNG claimed to have been used as transportation fuel corresponds with the amount of RNG placed onto the natural gas commercial distribution system and that such CNG/LNG is not double counted for RIN generation.

Since promulgation of the prior regulatory provisions in the RFS Pathways II rule,[254] many parties have requested that EPA approve pathways to allow the use of biogas as a biointermediate to produce various types of fuels (*e.g.,* steam methane reforming the biogas into hydrogen or using a Fischer-Tropsch process to turn biogas into renewable diesel). These parties have suggested that EPA should encourage these biogas-derived renewable fuels to increase the

[249] 87 FR 39600, 39635–51 (July 1, 2022).

[250] The regulations similarly allow RNG that has been placed on a commercial pipeline be withdrawn and used to produce renewable fuel.

[251] 79 FR 42128 (July 18, 2014).

[252] 40 CFR 80.1426(f)(10)(i).

[253] 40 CFR 80.1426(f)(11)(i).

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

production and use of advanced and cellulosic renewable fuels.

In the 2020–2022 RFS Standards Rule, we promulgated regulatory provisions that allowed for the generation of RINs from renewable fuels produced from biointermediates.[255] However, we did not include the use of biogas as a biointermediate at that time. While we recognized the opportunity to increase the availability of advanced and cellulosic biogas-derived renewable fuels in support of the statutory goals, we also noted that allowing biogas or contracted RNG to be used as an input to produce a fuel other than renewable CNG/LNG entails adding further layers of complexity to a system that is already challenging to implement and oversee. In response to the significant number of comments requesting the inclusion of biogas a biointermediate in the 2020–2022 RFS Standards Rule, we stated that we neither developed nor proposed the provisions that would be necessary to address the unique circumstances associated with biogas as a biointermediate and that we intended to address the use of biogas as a biointermediate in a future rulemaking.[256] We believed then, and still believe, that the previous biogas provisions[257] must be modified to ensure that biogas is not double counted in a situation where biogas may have multiple uses (*e.g.,* as renewable CNG/LNG or as a biointermediate).

3. The Biogas and Biogas RIN Disposition and Generation Chain

In this subsection, we introduce and briefly discuss a number of key concepts and terms that are used throughout our discussion of biogas regulatory reform, including the relevant parties that participate in the biogas disposition/generation chain.[258]

[255] 87 FR 39600 (July 1, 2022).

[256] See 87 FR 39600, 39641 (July 1, 2022).

[257] For purposes of this preamble, the previous biogas provisions refer to those regulatory requirements that apply for the generation of RINs from qualifying biogas under 40 CFR part 80, subpart M, that are being modified by this final action. These regulatory provisions will sunset and be replaced by the biogas regulatory reform provisions discussed in this section, which include a modified definition of biogas. Additionally, under the RFS program, biogas used to produce renewable fuels must be produced from renewable biomass. See id. (definition of ''renewable fuel''), Table 1 to 40 CFR 80.1426.

[258] For purposes of this preamble, we refer to the chain of parties that produce biogas, RNG and biogas-derived renewable fuels, distribute such products, use such biogas-derived renewable fuels as a transportation fuel, and generate and transfer RINs for biogas-derived renewable fuels collectively as the biogas disposition/generation chain.

a. Biogas and RNG

Under the previous biogas provisions, EPA broadly defined biogas as ''the mixture of hydrocarbons that is a gas at 60 degrees Fahrenheit and 1 atmosphere of pressure that is produced through the anaerobic digestion of organic matter.'' Biogas typically contains significant amounts of impurities and inert gases (*e.g.,* carbon dioxide) and must undergo pre-treatment before it can be used to produce transportation fuel (*e.g.,* CNG/LNG in vehicles). In order for commercial natural gas pipelines to accept injections of biogas, the biogas must first be upgraded to meet pipeline specifications prior to injection. In this action, we call this pipeline quality biogas RNG, and we define biogas to be the precursor to RNG. The biogas producer is the party that produces biogas at a biogas production facility, and the RNG producer is the party that produces RNG at an RNG production facility.

b. Renewable CNG and LNG From RNG

For biogas to be used as renewable CNG/LNG to fuel a vehicle, the treated biogas or RNG is compressed into compressed natural gas (renewable CNG) or liquified natural gas (renewable LNG) and then used in CNG/LNG engines as transportation fuel. Under our previous biogas regulations,[259] we required that parties demonstrate through contracts and affidavits that a specific volume of RNG was used as transportation fuel within the U.S., and for no other purpose. For RNG to renewable CNG/LNG, the chain of parties that are involved in ensuring that biogas is produced from renewable biomass and used as transportation fuel includes:

- The biogas producer (*i.e.,* the landfill or digester that produces the biogas)
- The party that upgrades the biogas into RNG (the RNG producer)
- The parties that distribute and store the RNG (*e.g.,* pipeline operators)
- The parties that compress the RNG into renewable CNG/LNG
- The dispensers of the renewable CNG/LNG (*e.g.,* refueling stations)
- The consumers of the CNG/LNG (*e.g.,* a municipal bus fleet)
- And any third parties that help manage the information and records needed to show that the biogas was produced from renewable biomass and used as renewable CNG/LNG.

If biogas is directly supplied to an end user via a private pipeline, the biogas disposition/generation chain can be much smaller; sometimes even being a single party if the same party produces the biogas, treats and compresses/liquifies it, and supplies an onsite fleet of CNG/LNG vehicles.

[259] 40 CFR 80.1426(f)(10)(ii), (f)(11)(ii).

4. Need for Regulatory Change

The previous biogas provisions lack specificity and clarity in several key areas, which, as EPA has gained experience in implementing the program, we have determined undermines EPA's ability to implement, oversee, and enforce the program. Critically, we have concerns that the existing regulations allow for double counting of biogas volumes or generating invalid RINs from biogas or RNG. These perversities could be exacerbated as EPA allows for multiple uses of biogas (*i.e.,* allows biogas to be used as a biointermediate). The lack of specificity and clarity has also led to a high degree of program complexity, unnecessarily burdening both EPA and industry and hindering effective oversight.

The previous biogas provisions do not specify how or where the quantity of CNG/LNG was to be measured, which party was the RIN generator, how a RIN generator was to demonstrate that the CNG/LNG was actually used as transportation fuel, or how the RIN generator demonstrated that the CNG/LNG was not double counted. The previous biogas provisions were also silent on whether and how parties could store biogas prior to and after registration, how parties reconcile stored volumes over periods of time, and when if ever such volumes had to be used as transportation fuel for RIN generation.

Due to the lack of specificity in those previous biogas provisions for how potential RIN generators would demonstrate that CNG/LNG was produced from renewable biomass and used as a transportation fuel, the registration requests that EPA received over the past several years varied considerably in their approaches. The main point of variation concerned the party that would generate the RINs. Approaches in registration requests have included:

- Parties that use renewable CNG/LNG in a specified fleet (*e.g.,* fleet operators)
- Parties that dispense renewable CNG/LNG
- Parties that generate RNG from qualifying biogas
- Parties that produce the qualifying biogas for renewable CNG/LNG generation

• Marketers that organize contracts between RNG producers and CNG/LNG users.

EPA did not envision this broad range of differing approaches to RIN generation for renewable CNG/LNG when we designed the previous biogas regulations. While these regulations required registrants to demonstrate in their requests that another party could not double count the quantity of RINs generated for a volume of biogas and renewable CNG/LNG,[260] the regulations are so open-ended that multiple parties—the renewable CNG/LNG producer, the party distributing the CNG/LNG, biogas producer, fleet owners, and/or dispensing stations—could be in a position to claim a single volume. That is, while the regulations prohibit the double counting of RIN generation for the same quantity of renewable CNG/LNG, they also inadvertently made it relatively easy for double counting to occur.

The previous biogas provisions also allowed for a single renewable CNG/LNG dispenser to contract with multiple RNG producers and allowed a single RNG producer to contract with multiple CNG/LNG dispensers. This flexibility allowed for the creation of network of contracts which encompass many RNG producers, many RNG distributers and marketers, and many CNG/LNG dispensers, creating a complex paperwork system for EPA to track and that increased the difficulty of effectively overseeing the program.

The regulatory revisions outlined in this section are necessary to promote expansion of renewable fuel volumes, to prevent invalid RINs, and to allow EPA and industry to effectively ensure compliance, as discussed in more detail below.

a. Supporting the Broad Goals of the RFS Program

The broad goals of the RFS program are to reduce GHG emissions and enhance energy security through increases in renewable fuel use over time. Inclusion of new types of renewable fuel or expansion of existing types of renewable fuel in the program can help to accomplish these goals. Any fuel that is produced from renewable biomass and is used as transportation fuel (as defined in the Clean Air Act) has the potential to participate in the RFS program, provided in satisfies the applicable statutory and regulatory requirements. Biogas is already a major source of renewable fuel, with RNG used as renewable CNG/LNG currently representing the vast majority of cellulosic biofuel. As discussed in Section III.B.1, use of RNG has been growing at a rapid rate since 2016 through the incentives created by the cellulosic RIN under the RFS program, in addition to LCFS credits in California and other states. However, the opportunity for continued growth of RNG is expected to be constrained in the future by two factors. First, the economics of developing biogas facilities becomes increasingly challenging for smaller facilities, and particularly for facilities located more remotely from natural gas pipeline interconnects. The first facilities brought into the program tended to be the largest and most economical, with it becoming increasingly costly to bring on incremental volume over time. Second, as discussed in Section III.B.1., the rate of growth in the consumption capacity of the in-use fleet of CNG/LNG vehicles is expected to slow. When the program started in 2016, there was a sizeable existing fleet of CNG/LNG vehicles that were operating on fossil natural gas and that could quickly be used to generate RINs through establishing contracts for RNG. Since the use of RNG has been saturating the existing in-use CNG/LNG vehicle fleet, particularly the largest and most economical fleets, the use of biogas as a feedstock for renewable fuel production will be increasingly constrained by the much slower growth in CNG/LNG fleet sales. At the same time, based on the number of existing landfills[261] and wastewater treatment facilities and the potential for significant expansion of anaerobic digesters,[262] there exists significant potential to increase the productive use of biogas by using it as a biointermediate to produce renewable fuel under the RFS program. By tapping into the greater market for that biogas that can be economically converted to other renewable fuels, the impending constraints on the use of biogas as a feedstock for renewable fuel production can be mitigated.

The use of biogas to produce fuels other than renewable CNG/LNG is also consistent with the statute's focus on growth in cellulosic biofuel over other advanced biofuels and conventional renewable fuel after 2015.[263] However, due to concerns with the potential double counting of biogas/RNG for RIN generation, EPA has not registered parties to generate RINs for biogas used for fuels other than renewable CNG/LNG under the existing regulations, so biogas use has instead been limited to the CNG/LNG vehicle market under the RFS program. Allowing the program to incorporate biogas-derived renewable fuels other than renewable CNG/LNG would support the increase in usage of renewable fuels which can reduce GHGs emissions and promote energy independence.

b. Preventing Double Counting and Fraud

In order for the RFS program to function, the RIN market must maintain foundational integrity: namely, the parties that transact RINs and use RINs for compliance must have confidence that those RINs are valid. While the vast majority of RINs generated over the RFS program's history have not been found to be invalid, a non-trivial quantity of invalid RINs have also been generated.[264] The significant value of the RINs, particularly cellulosic RINs, provides incentives for fraudulent generation, and complicated renewable fuel production and distribution systems, such as the contractual network for demonstrating that CNG/LNG qualifies as renewable fuel described in Section IX.A.2, provide opportunities for fraudulent behavior. Fraudulent RINs can be generated, for example, by parties fabricating reports or records to generate RINs for volumes of biogas that have been used for a different, non-transportation fuel purpose. Furthermore, the more complicated the regulatory requirements and data systems, the more likely it is that parties may inadvertently generate invalid RINs due to simple errors such as reliance on a faulty meter that measured volumes incorrectly or made a calculation error. That is, invalid RIN generation, including double counting of RINs (generating more than one RIN for the same ethanol-equivalent gallon of renewable fuel), can result from either intentional or unintentional actions.

In all cases of double counting, some or all of the RINs generated would be invalid and may additionally be deemed fraudulent. The generation of invalid RINs can have a deleterious effect on

[260] See 40 CFR 80.1426(f)(11)(ii)(H), which states that ''[n]o other party relied upon the volume of biogas/CNG/LNG for the creation of RINs.''

[261] *https://www.epa.gov/lmop/landfill-gas-energy-project-data.*

[262] *https://www.epa.gov/agstar/livestock-anaerobic-digester-database.*

[263] For years after 2015, conventional renewable fuel remains constant at 15 billion gallons, and non-cellulosic advanced biofuel increases by no more than 0.5 billion gallons annually. Annual increases in cellulosic biofuel, in contrast, accelerate from 1.25 billion gallons in 2016 to 2.5 billion gallons in 2022.

[264] For more information, see EPA's Civil Enforcement of the Renewable Fuel Standard Program page available at: *https://www.epa.gov/enforcement/civil-enforcement-renewable-fuel-standard-program.*

RIN markets and impose a significant burden on regulated parties and EPA to identify and replace those invalid RINs, take enforcement action against liable parties, and remedy the invalidity.

The potential for double counting of biogas, RNG, and biogas-derived renewable fuels is a significant concern since it can undermine the credit system that EPA uses to implement the statutory volume requirements under CAA section 211(o). Even though the existing regulations prohibit such double counting,[265] we have concerns that those regulations and the complex system of contracts and documentation they entail do not enable EPA to detect or protect against the double counting of RINs from biogas feedstocks because of the challenge tracking biogas through commercial pipelines.

Invalid RINs can also create adverse market effects. In the short term, invalid RIN generation could oversupply the credit market and adversely impact credit values. In the longer term, remediation of invalid RINs could invalidate the data upon which EPA bases its projections of future supply to set standards and undermine investment in the growth of valid renewable fuels.

Having a robust means of avoiding double counting and fraud is particularly important because once EPA begins accepting registration requests for biogas to be used as a biointermediate and biogas-derived renewable fuels other than renewable CNG/LNG, the opportunities for the double counting of biogas could increase dramatically. For example, without a robust system in place a party could easily generate RINs for a quantity of biogas used to produce RNG for use in CNG/LNG vehicles and then, through a complex contractual network, attempt to allow a different party to generate a RIN for production of other renewable fuel generated from the same volume of RNG.

We believe that the biogas regulatory reform provisions we are finalizing virtually eliminate the potential for double counting and minimize opportunities for fraud by specifying the party that generates RINs, by holding all directly regulated parties in the biogas disposition/generation chain liable for transmitting or using invalid RINs, by tracking RNG through reporting requirements, and by leveraging third-party oversight mechanisms (*i.e.,* third-party engineering reviews, RFS QAP, and annual attest engagements).

[265] See 40 CFR 80.1426(f)(11)(i)(F).

c. Enhancing Program Simplicity and RIN Integrity

While the previous biogas provisions provide flexibility, as described in Section IX.A.2, they have also resulted in a complex program that is overly burdensome for both EPA and industry. Under the previous biogas provisions, parties demonstrate that biogas is used as renewable CNG/LNG for RIN generation through an extensive network of contractual relationships and documentation that shows that a specific volume of qualifying biogas is used as transportation fuel in the form of renewable CNG/LNG. These demonstrations occur during registration in the form of extensive paperwork, including contracts and associated documentation; registration packages can sometimes number over a thousand pages of contracts for a single RNG production facility. These contracts can also cover multiple facilities, creating an ever more complex network of contracts.

The potential expanded use of biogas as a biointermediate and RNG as a feedstock to produce renewable fuels would make the program under the previous biogas provisions impracticable to oversee and, as discussed above, more susceptible to double counting and fraud. Since biogas may have multiple uses, it is crucial to minimize the potential for generating invalid or fraudulent RINs, including the double counting of RINs. As more uses of biogas are allowed under the program, additional regulatory measures are necessary because EPA will be tracking and overseeing increased volumes of biogas, and we want to ensure a program design that enables EPA to effectively track and oversee larger volumes of biogas (particularly in instances where biogas is converted into RNG and placed into a natural gas commercial pipeline system) going to multiple end uses. We also want to avoid situations in which opaque contractual mechanisms could potentially allow multiple parties to claim that the same volume of biogas is used as two or more biogas-derived renewable fuels.

One of the revisions EPA is finalizing in this rulemaking is to track the flow of RNG in EMTS. Doing so will simplify oversight, ensure that quantities of biogas-derived renewable fuels used as transportation fuel are real, and provide confidence to encourage investment in these fuels. The biogas regulatory reform program includes those parties, and only those parties, that are necessary and best able to demonstrate the valid use of renewable fuel use for transportation: the biogas producer, the RNG producer, and the party that can demonstrate its use for transportation (*e.g.,* the renewable CNG dispenser). Each party has a set of clearly defined roles and responsibilities under the program.

5. Summary of Changes

In this rulemaking, EPA proposed to specify requirements for different parties within the biogas disposition/generation chain. We also proposed to expand how biogas can be used through provisions allowing biogas to be used as a biointermediate such that renewable fuel produced from biogas could be produced through sequential operations at more than one facility and allowing RNG to be used as a feedstock to produce a different renewable fuel. We are finalizing many elements of biogas regulatory reform largely as proposed. The key elements of the biogas regulatory reforms that we are now finalizing include the following:

- Specification of the party that upgrades the biogas to RNG (the RNG producer) as the RIN generator.
- A requirement that the RNG producer assign RINs generated for the RNG to the specific volume of RNG when the volume is injected into a natural gas commercial pipeline system.
- A requirement that the party that can demonstrate that the RNG was used as transportation fuel may separate the RIN.
- Specific regulatory requirements for key parties (*i.e.,* biogas producer, RNG producer, RNG RIN owners, and RNG RIN separators) in the RNG production, distribution, and use.
- Conditions on the use of biogas and storage of RNG prior to registration.
- Specific provisions to address when biogas is used as a biointermediate and when RNG is used as a feedstock.

These elements are applied to the following parties:

- The party that produces the biogas (the biogas producer).
- The party that upgrades the biogas to RNG, injects the RNG into the natural gas commercial pipeline system, and generates/assigns the RIN to the RNG (the RNG producer).
- Any party that transfers title of the assigned RIN (RNG RIN owner).
- The party that demonstrates that the RNG was used as transportation fuel in the form of renewable CNG/LNG (the RNG RIN separator) or used as a feedstock to produce a renewable fuel other than renewable CNG/LNG.

We discuss each of these key elements and parties in more detail in the following sections.

Regulatory requirements for each of these key activities and parties are necessary to ensure that the biogas is produced, converted to RNG, and eventually used as transportation fuel consistent with CAA and regulatory requirements. Specifying the requirements applicable to each party enables EPA to take a streamlined regulatory approach to the production, distribution, and use of RNG that allows for the flexible use of RNG without imposing strict limitations on which parties can take title to and use the RNG.

Furthermore, we are also sunsetting regulatory provisions that will no longer be necessary. For example, much of the documentation of contracts between each party in the biogas distribution/generation chain previously required to be submitted to EPA at registration will no longer be necessary to submit.

Finally, based on comments requesting more time for parties to comport with the biogas regulatory reform provisions, we are providing more time for both new and existing registrants to come into compliance, as discussed in Section IX.F.

We did not propose to revisit or reopen the pathways for biogas established in the 2014 RFS Pathways II rule and are therefore not addressing any issues or comments received on the pathways themselves. We will continue to review pathway petitions under 40 CFR 80.1416 and may take separate regulatory action on additional pathways for biogas as appropriate in the future.

*B. Biogas Under a Closed Distribution System*

Under the previous biogas provisions, there were two approaches for generating RINs from biogas to renewable CNG/LNG: (1) biogas in a closed, private, non-commercial distribution system that is compressed to renewable CNG/LNG, and (2) biogas upgraded to RNG, injected into a commercial pipeline system, and then compressed to renewable CNG/LNG.[266] The focus of this regulatory reform deals with RNG injected onto the natural gas commercial pipeline system. We are therefore finalizing as proposed only minor modifications to the existing regulatory provisions for biogas used to produce a renewable fuel when the biogas is produced and made into a biogas-derived renewable fuel in a closed distribution system. Because it is typically only a single party participating in a closed distribution system (*i.e.,* the same party that produces the biogas is the same party that converts the biogas to renewable CNG/LNG and then uses that biogas in their own CNG/LNG fleets), there is little opportunity for the double counting of biogas through multiple parties claiming the same volume across the biogas distribution/generation chain.

We are finalizing as proposed that parties that generate RINs for biogas to renewable CNG/LNG via a closed distribution system will continue to operate under similar provisions to the previous biogas provisions. We are also finalizing as proposed a requirement that when the biogas producer is a separate party from the party that generates RINs for biogas to renewable CNG/LNG in a closed distribution system, the biogas producer will have to separately register with EPA. This provision ensures that biogas producers are treated consistently throughout the program and helps EPA identify how parties are related in the biogas distribution/generation chain. We recognize that this may require some parties to update their registration information with EPA, but we do not expect this to require new third-party engineering reviews or the resubmission of registration materials.

To help ensure consistency in the regulatory requirements for all biogas-derived renewable fuels, we are moving the provisions for biogas to renewable CNG/LNG via a closed distribution system into the new 40 CFR part 80, subpart E. We sought comment on whether and how to streamline the regulatory requirements for biogas to renewable CNG/LNG via a closed distribution system. We did not receive significant comments regarding parties producing renewable CNG/LNG from biogas via a closed distribution system, and we are finalizing that we are moving these provisions to subpart E as proposed.

*C. RNG Producer as the RIN Generator*

For biogas upgraded to RNG and placed on a natural gas commercial pipeline system, we are finalizing as proposed that RNG producers will be the sole RIN generators, and that they will generate RINs for RNG they produce and inject into a commercial pipeline. The previous regulations allowed any party to generate RINs from biogas-derived renewable fuels, even parties that were not part of the biogas distribution/generation chain. In the RFS Pathways II rule, we did not specify a RIN generator because we believed that the complexities of the production and distribution of biogas-derived renewable fuels warranted a case-by-case approach to RIN generation.[267] We noted that we would continue to monitor RIN generation practices and that we might reconsider specifying the RIN generator for biogas-derived renewable fuels at a later date. Based on our experience implementing the program since then, and in light of the expansion in the use of biogas as a biointermediate and RNG as a feedstock, we now believe that it is important to designate a RIN generator.

We believe that RNG producers are best positioned to generate the RINs for two reasons. First, one of the goals of biogas regulatory reforms is to minimize the potential for double counting of biogas or RNG since such biogas or RNG could potentially be used to produce multiple types of fuels. By designating RNG producers as the RIN generators, the RINs will effectively be tracked in EMTS from RNG injection through withdrawal via the assignment, separation and/or retiring of RINs, as discussed in more detail in Section IX.D. This approach significantly reduces double counting concerns since a specific volume of RNG will have corresponding RINs assigned to it, and by specifying that the RINs can only be separated under specific circumstances.

Second, we believe RNG producers are also well positioned to determine whether the RNG was produced from qualifying biogas and to determine the correct amount of biomethane that will qualify for RIN generation. RNG producers typically add non-renewable components to biogas to make pipeline quality RNG. They are often the only party aware of the non-renewable components, and the only party in a position to measure the biomethane content of the RNG prior to introducing non-renewable components.

We also considered designating other parties as the RIN generator. For example, we considered designating the party that produces or uses the renewable CNG/LNG as the RIN generator. However, if we finalized such an approach, then we will largely forgo any ability to track assigned RINs to volumes of RNG in EMTS because the RNG will have already traversed the entirety of the natural gas commercial pipeline system before the RIN was generated and assigned. This approach will not remedy the double counting and tracking concerns under the existing program. The RNG would still have to be tracked via a complicated series of contractual relationships instead of electronically in EMTS. The downstream party and EPA acting in its oversight capacity would still have to go

[266] See 40 CFR 80.1426(f)(10) and (11).

[267] 79 FR 42128, 42144 (July 18, 2014).

to great lengths to ensure that the RNG was not double counted before the RIN was generated.

We recognize that the approach we are finalizing will affect a number of parties that are currently registered to generate RINs for biogas to renewable CNG/LNG, and we specifically sought comment on our proposal to designate the RNG producer as the RIN generator for RNG injected into a natural gas commercial pipeline system. We received a number of comments relating to who should be the RIN generator for RNG RINs. Multiple commenters suggested that our approach should be broader and that we should allow third parties, such as marketers, to be the RIN generator. These commenters stated that smaller entities might not have the expertise necessary and would not want to take on the liability associated with RIN generation. Commenters also expressed concern regarding the need to re-negotiate contracts that had previously let a party other than the RNG producer generate RINs.

Given that in this action we are expanding the use of biogas as a biointermediate and RNG as a feedstock, we believe it is important for parties that generate RINs in the RFS program to be held responsible for complying with the regulations, and in general we believe that parties that have a direct role in the production or use of a fuel are the more appropriate parties to generate RINs. Parties involved in the production of feedstocks or renewable fuel should not be allowed to shift liability to third parties. While stakeholder comments provided perspectives on market dynamics, these commenters did not explain how allowing third parties to generate RINs would directly improve compliance and enforcement of this expanded program.

Additionally after reviewing stakeholder comments and engaging directly with companies,[268] we remain convinced that this step is necessary to implement the other proposed changes discussed below. By making the RNG producer the RIN generator, we will greatly improve our ability to track the movement of the RNG via RINs assigned at the point of injection as discussed in Section IX.D. This change will also simplify the program while improving our ability to effectively oversee it. In response to concerns on contract negotiation timing, we are finalizing modifications to our proposed implementation date, as discussed in Section IX.F.

[268] See ''Set Rule Log of Meetings,'' available in the docket for this action.

Based on our experience with CNG/LNG, and from stakeholders' experience in California's LCFS program, we recognize that third parties will likely serve a useful role in supporting regulated parties in brokering and trading biogas, RNG, and biogas-derived renewable fuel. We also believe that biogas producers, RNG producers, and RNG RIN separators would likely contract with third parties to help them comply with the proposed regulatory requirements by preparing and submitting registration requests and periodic reports. Since our system for registration and RIN generation allows third parties to assist the regulated party in preparing to comply with the applicable regulatory requirements (*e.g.,* by helping to prepare reports, broker RIN transactions, etc.), and we are not planning on changing this allowance under this rule, we believe this should provide most of the functionality the commenters requested.

*D. Assignment, Separation, Retirement, and Expiration of RNG RINs*

EPA is finalizing revisions to the regulations to specify how parties will assign, separate, and retire RINs generated for RNG. Under the previous regulations, RINs were generated and immediately separated after any party in the biogas disposition/generation chain demonstrated that a specific amount of RNG was used as transportation fuel. Because RINs were generated and simultaneously separated based on the same event, the previous biogas provisions did not provide tracking of RNG or renewable CNG/LNG in EMTS through RIN assignment and separation.

We are finalizing as proposed that the RNG producer must assign any and all RINs generated for a given volume of RNG to the same volume of RNG at the point of injection, and the RINs must follow transfer of title of that RNG until it is withdrawn from the same natural gas commercial pipeline system.[269] The purpose of this requirement is to ensure that the RIN, as tracked through EMTS, follows the transfer of title of the RNG as the RNG moves through the natural gas commercial pipeline system.

Regarding RIN separation, we are finalizing with technical modifications the proposal that only the party that demonstrates that the RNG was used as transportation fuel will be eligible to

[269] For purposes of this preamble, when we refer to the RNG producer we are collectively referring to the party that produces and injects the RNG into the natural gas commercial pipeline system or imports the RNG into the covered location. Unless otherwise specified, all proposed requirements as part of this proposal apply to both RNG producers and RNG importers.

separate the RINs generated for the RNG from the RNG itself., This party is defined as the RNG RIN separator. This party may either be the party that withdrew the RNG from the natural gas commercial pipeline system or the party that produced or oversaw the production of the renewable CNG/LNG from the RNG. This is a different approach than the prior regulations. Previously, the party that generates the RINs from a volume of biogas separates any RINs generated for that biogas immediately after the party has demonstrated that the biogas was produced from renewable biomass under an EPA-approved pathway and used as transportation fuel. Separation does not necessarily occur at the end of the biogas distribution/generation chain, which necessitates tracking via contractual relationships, as discussed above, and forgoes any ability for EMTS to track the assigned RINs as the volumes of RNG move through the natural gas commercial pipeline system. Our changes will allow for RINs assigned to a given volume of RNG to be tracked via EMTS as the RNG moves through the natural gas commercial pipeline system from injection to withdrawal. Similarly, we are finalizing as proposed the clarification that the provisions that require obligated parties to separate assigned RINs when they take title to any assigned RINs do not apply to RINs assigned to RNG. Allowing obligated parties to separate assigned RINs for RNG would undermine the purpose of our proposal to use RINs assigned to RNG in EMTS to track transfers of RNG.

In the case of RNG used to produce renewable CNG/LNG, the party that obtains the documentation needed to demonstrate that the RNG was used to produce transportation fuel in the form of renewable CNG/LNG is best positioned to separate the RIN. This is analogous to the provisions that require parties blending denatured fuel ethanol into gasoline to separate any assigned RINs for the denatured fuel ethanol at fuel terminals (*i.e.,* the point at which it is reasonable to assume that the denatured fuel ethanol will be used as transportation fuel).[270] Similarly, once a party has turned RNG into renewable CNG or renewable LNG, we can reasonably assume that the renewable CNG or renewable LNG will be used as transportation fuel. We proposed that the party that separates RNG RINs must have withdrawn the RNG from the natural gas commercial pipeline system and produced renewable CNG/LNG from that RNG, among other

[270] 40 CFR 80.1429.

requirements. We received comments that the party that withdraws the RNG from the natural gas commercial pipeline system is not always the same party that converts RNG into renewable CNG/LNG. We believe either the party that withdraws the RNG from the natural gas commercial pipeline system and produces renewable CNG/LNG from that RNG or the party that converts RNG into renewable CNG/LNG could have sufficient information to be positioned to demonstrate that the RNG is used as transportation fuel, so we have finalized the regulations to allow either party to separate RNG RINs.

To address the potential issue of double counting an RNG RIN where a party claims that the RNG is used both as renewable CNG/LNG and as a different biogas-derived renewable fuel, we are finalizing as proposed the requirement that parties that use RNG to produce a biogas-derived renewable fuel other than renewable CNG/LNG will have to retire the assigned RINs for the RNG used as a feedstock and then generate a separate RIN using the procedures for RIN generation for the new renewable fuel.

RNG RINs will expire consistent with the current regulatory requirements at 40 CFR 80.1428(c). Under 40 CFR 80.1428(c), any RIN that is not used for compliance purposes for the year in which it was generated, or for the following year, is considered an expired RIN, and expired RINs are considered invalid RINs under 40 CFR 80.1431. What this means for RNG RINs is that if no party separates an RNG RIN or retires the RNG RIN to produce renewable fuel by the annual compliance deadline for the compliance year following the year in which that RNG RIN was generated, the RNG RIN will expire. For example, if a RIN is generated for RNG injected into the natural gas commercial pipeline system in 2024, then that RNG RIN will expire after the 2025 annual compliance deadline. If no party separated the assigned RIN for the RNG because no party was able to demonstrate that the RNG was used as transportation fuel or as a feedstock, then the RNG RIN will expire and no longer be usable for compliance purposes. We note that this approach is consistent with existing regulations for how RIN expiration works under the RFS program generally. We also note that that this provision will allow for at least 15 months for any assigned RNG RIN to be separated (*i.e.,* a RIN generated and assigned in December of a compliance year will have at least 15 months before it expires after the subsequent compliance year's annual compliance deadline), and in many cases much longer. We believe this to be sufficient time for parties to demonstrate that the RNG with the assigned RINs was used as transportation fuel and will help encourage parties to use RNG as transportation fuel under the RFS before the RIN expires.

Separating the RIN assignment and RIN separation roles provides multiple benefits to both EPA and the regulated community. First, this approach will significantly increase the ability for the title to RNG to be tracked and overseen, because the transfer of title to RNG will follow the assigned RIN and will be reported in EMTS. EPA and third parties will be able to track the parties that transferred title to the RNG and follow the movement of the RNG via the assigned RIN in EMTS, as opposed to having to track a complex series of contractual relationships between each and every party in the RNG distribution system. This approach will also greatly simplify the auditing process for both EPA and for third parties, allowing for increased program oversight.

Second, this approach allows us to streamline the registration, reporting, and recordkeeping requirements for RNG and RNG RINs by utilizing EMTS for tracking. This creates a number of efficiencies. With regard to registration, it eliminates the need for parties to submit contracts at registration, as discussed in Section IX.A. For reporting, since the RNG and RNG RINs will be tracked in EMTS, we will no longer require the reporting of affidavits and other documentation concerning the transfer of RNG that we currently require to ensure that the RIN generator has the information needed to demonstrate that a specific volume of RNG was used as transportation fuel. For recordkeeping, EMTS will electronically provide real-time data concerning how a given volume of RNG is transferred and ultimately used. This eliminates the need for the existing provisions that require RIN generators to obtain documents from every party in the biogas distribution/generation chain in the form of additional contracts, affidavits, or real-time electronic data. These registration, reporting, and recordkeeping requirements significantly streamline program implementation for EPA and reduce the compliance burden on regulated parties.

Third, this mitigates the risk of counting a given volume of RNG more than once because we are clearly specifying the point in the process when RNG RINs must be generated (*i.e.,* at the point where RNG is injected into the natural gas commercial pipeline system) and the point in the process when RNG RINs must be separated (*i.e.,* when the RNG is demonstrated to be used as a transportation fuel). Because the RNG can only be injected into the natural gas commercial pipeline system once and because an assigned RNG RIN can only be separated once, this specificity virtually eliminates a party's ability to double count the RNG at the point of injection or claim that a given quantity of RNG was used for more than one purposes.

*E. Structure of the Regulations*

Due to the comprehensive nature of the biogas regulatory reform provisions, we are creating a stand-alone subpart rather than embed them in the rest of the RFS regulatory requirements in 40 CFR part 80, subpart M. Thus, we are finalizing as proposed the creation of a new subpart for biogas-derived renewable fuels—subpart E in 40 CFR part 80. This new subpart includes provisions not only for biogas and RNG used to produce renewable CNG/LNG, but also for other biogas-derived renewable fuels including biogas cases where biogas is used as a biointermediate and RNG is used as a feedstock. The provisions for these fuels under subpart M are being copied into the new subpart E, and the provisions within subpart M are being phased out as described in Section IX.F.

Based on our general approach adopted in the Fuels Regulatory Streamlining Rule,[271] we are structuring the new subpart for biogas-derived renewable fuels as follows:

- Identify general provisions (*e.g.,* implementation dates, scope, applicability etc.).
- Articulate the general requirements that apply to parties regulated under the subpart (*e.g.,* biogas producers, RNG producers, and RNG RIN separators).
- Articulate the specific compliance and enforcement provisions for biogas-derived renewable fuels (*e.g.,* registration, reporting, and recordkeeping requirements).

We believe that this subpart and structure will make the biogas-derived renewable fuel provisions more accessible to all stakeholders, help ensure compliance by making requirements more easily identifiable, and help future participants in biogas-derived biofuels better understand regulatory requirements in the future.

*F. Implementation Date*

In response to extensive request from public comment to provide more lead time for the implementation of the biogas regulatory reform provisions, we

[271] See 85 FR 78415–78416 (December 4, 2020).

are finalizing more time than proposed for both new parties and existing registrants to come into compliance with the biogas regulatory reform provisions. Parties that are registered to generate RINs for renewable CNG/LNG prior to July 1, 2024 will have until January 1, 2025 to come into compliance with the biogas regulatory reform provisions. Parties registered July 1, 2024 or after will have to meet the biogas regulatory reform provisions beginning July 1, 2024. On January 1, 2025, all parties must comply with the biogas regulatory reform provisions and only biogas and RNG produced under the biogas regulatory reform provisions are eligible for RIN generation. Below we discuss our proposed timeline, the comments we received, and how we adjusted the timeline based on the comments.

Recognizing the need to provide a transition period for parties that are already generating RINs for biogas under the prior provisions to the biogas regulatory reforms, we proposed that all parties operating under the previous biogas provisions would have to come into compliance with the proposed biogas regulatory reform provisions by January 1, 2024. We also proposed that parties that injected RNG into the natural gas commercial pipeline system under the previous biogas provisions prior to January 1, 2024 could use the RNG for the generation of RINs under the previous biogas regulatory provisions until January 1, 2025. We believed at the time that this was enough time for parties to come into compliance with the proposed biogas regulatory reform provisions and utilize for RIN generation the RNG stored on the natural gas commercial pipeline system. We sought comment on whether more time was needed for parties to transition to the proposed biogas regulatory reform provisions.

In response, we received significant public comment suggesting that more time was needed by both parties already registered under the previous biogas provisions and parties looking to register new facilities under the biogas regulatory reform provisions. Commenters suggested that the new testing and measurement requirements for biogas and RNG could take considerable time for parties to install compliant meters and arrange for independent third-party engineers to ensure that such meters were installed consistent with the new regulatory requirements. Commenters suggested that the implementation timeline should also consider facilities that are not currently registered because it can take years for an RNG project to be developed and many new projects may need modification to comport with the new requirements. Additionally, several commenters suggested that it would take more than the approximately six months allotted for the renegotiation of contracts with parties that produce, distribute, and use RNG to align with the new requirements. Parties suggested that by not providing enough lead time to comport with the measurement requirements and to allow parties to renegotiate contracts, EPA would strand a significant volume of RNG that would otherwise be eligible for use as renewable CNG/LNG under the RFS program. Some commenters suggested that EPA should provide an additional year over what was proposed (*i.e.,* a January 1, 2025 start date instead of the proposed January 1, 2024 date), while others suggested EPA push the deadline to January 1, 2026.

In response to the requests for more time for existing registrants, we are finalizing a start date of January 1, 2025, for facilities registered under the previous biogas provisions by July 1, 2024. We believe this extension should afford enough time for those facilities to come into compliance with the new regulatory requirements. It would in practice allow for almost a year and a half for parties to update their facilities to comport with the new regulatory requirements, update their registration information with EPA, and renegotiate their contracts. This would also provide existing registrants enough time to use any RNG stored on the natural gas commercial pipeline system before the new RIN generation requirements for RNG begin on January 1, 2025.

In response to the requests for more time for new registrations, we are finalizing a start date of July 1, 2024, which affords new parties enough time prepare to meet the new regulatory requirements for biogas regulatory reform. Because these facilities are still preparing to come into the RFS program, we believe that a full year is sufficient for them to make adjustments to their facilities and contractual relationships prior to registration. Furthermore, we must balance the need to provide facilities that have planned to participate in the RFS under the previous biogas provisions with our ability to implement and oversee the program.

We are finalizing as proposed that any RIN generators under the previous biogas provisions must generate RINs for RNG stored in the natural gas commercial pipeline system by January 1, 2025. As stated in the proposal, we believe this is a sufficient amount of time to utilize the amount of stored RNG as transportation fuel, and it is important to begin the tracking in EMTS via the RIN of all RNG under the RFS program as soon as practicable. A January 1, 2025 deadline may encourage existing registrants to comply with the biogas regulatory reform provisions prior to the deadline because the RNG produced under those existing registrations may have difficulty using the RNG as transportation fuel for RIN separation by the January 1, 2025 deadline.

To ensure a smooth transition, we are requiring that existing registrants submit registration updates comporting with the biogas regulatory reform provisions no later than October 1, 2024. We anticipate that 3 months is enough time for EPA to process the registration requests of the existing registrants; however, we encourage existing registrants to submit updates prior to the deadline if able to ensure a smooth transition to the biogas regulatory reform provisions. Existing RIN generators will be allowed to generate RINs under the previous biogas regulatory reform provisions for biogas and RNG used as transportation fuel prior to January 1, 2025.[272] Any RINs generated for biogas used as transportation fuel or RNG on or after January 1, 2025 must adhere to the biogas regulatory reform provisions.

In addition to extending some of the deadlines, to further address timing concerns raised by commenters related to the implementation of this biogas regulatory reform, we are finalizing several changes based on comments to the proposed provisions themselves which are designed to allow for a smoother transition to the reformed biogas regulatory provisions. These changes to what we proposed include, but are not limited to, streamlining the registration process for existing registered biogas and RNG production facilities by no longer requiring certificates of analysis for biogas and RNG at initial registration, no longer requiring at registration waivers from pipelines for RNG that did not meet applicable pipeline specifications, and removing the proposed emissions-related registration requirements. Also, as discussed in Section IX.H.2, we are intending to update our reporting

[272] We expect that RINs generated for biogas demonstrated to be used in as transportation fuel by December 31, 2024, under the previous biogas provisions will be generated by February 2025. Typically, because the RIN generator must collect documentation from various parties in the contractual chain to ensure that the biogas or RNG was used as transportation fuel prior to RIN generation, RIN generation can take around a month after the biogas or RNG was used as transportation fuel.

systems to more readily accommodate the submission of reports to streamline and modernize the submission of biogas and RNG-related information under biogas regulatory reform.

*G. Definitions*

We are finalizing with modifications the proposed definitions of various regulated parties, their facilities, and the products related to the production of biogas-derived renewable fuels. We are also finalizing with modifications the proposed definitions of other terms as necessary for clarity and consistency. We have modified the proposed definitions related to biogas regulatory reform based on public comments and describe those changes in more detail either below or in the RTC document.

We are also finalizing the proposal to move and consolidate all defined terms for the RFS program from 40 CFR 80.1401 to 80.2. We are doing this because we moved all of the non-RFS fuel quality regulations, including the relevant definitions, from 40 CFR part 80 to part 1090 as part of our Fuels Regulatory Streamlining Rule.[273] As such, it is no longer necessary to have separate definitions sections for 40 CFR part 80, subpart M, as only requirements related to the RFS program are housed in 40 CFR part 80. We are not changing the meaning of the terms moved from 40 CFR 80.1401 to 80.2, but are simply relocating them to consolidate the definitions that apply to RFS in a single location. Because we have consolidated all definitions for the RFS program into 40 CFR 80.2, any newly defined terms under this action appear in 80.2.

For parties regulated under the biogas regulatory reform provisions, we are finalizing several new terms to specify which persons and parties are subject to the revised regulatory requirements in a manner that is consistent with our approach under our other fuel quality and RFS regulations. For example, a biogas producer is defined as any person who owns, leases, operates, controls, or supervises a biogas production facility, and a biogas production facility is any facility where biogas is produced from renewable biomass that qualifies under the RFS program. The same framework for applies to RNG producers.

Under the previous RFS regulations, the term ''biogas'' is used to refer to many things and its use may differ depending on context. In some cases, we distinguish between raw biogas, *i.e.,* biogas collected at a landfill or through a digester that contains impurities and large portions of inert gases, and pipeline-quality biogas which has many of the impurities removed for distribution through a commercial pipeline. Some stakeholders also use the pipeline-quality biogas term interchangeably with renewable CNG or renewable LNG, which are renewable fuels produced from biogas. To clarify our intent, we are finalizing specific definitions for biogas-derived renewable fuel, biogas, treated biogas, biomethane, and renewable natural gas (RNG).

''Biogas'' is often used to broadly mean any renewable fuel used in the transportation sector that has its origins in biogas. However, in the context of the RFS program, we have learned that it is necessary to distinguish between these products. We are therefore finalizing a definition of ''biogas-derived renewable fuel'' that includes renewable CNG, renewable LNG, or any other renewable fuel that is produced from biogas or its pipeline-quality derivative RNG now or in the future.

We are defining biomethane as exclusively methane that is produced from renewable biomass. We believe a separate definition for biomethane is important because biomethane (exclusive of impurities and inert gases often found with biomethane in biogas) is what RIN generation is based on. In order to ensure the appropriate measurement of biomethane for RIN generation for RNG, we issued guidance under the existing regulations that cover cases where non-renewable components are added to biogas, and we are codifying provisions based on that previously issued guidance in this action.[274] Biomethane is a component of biogas, RNG, treated biogas, renewable CNG, and renewable LNG, all of which, under the definitions being finalized in this action, must be produced through anaerobic digestion of renewable biomass.

We are defining biogas as a mixture including biomethane that is produced from anaerobic digestion and may have undergone some processing to remove water vapor, particles, and some trace gases, but requires additional processing (such as removal of carbon dioxide, oxygen, or nitrogen) to be suitable for use to produce a biogas-derived renewable fuel. This new definition of biogas is intended to make it explicit that biogas includes gas collected at landfills or through a digester before that biogas is either upgraded to produce RNG or is used to make a biogas-derived renewable fuel, which was intended but not stated in the previous definition. Gas containing biomethane that has undergone treatment to remove components such that it is suitable for use to produce a biointermediate or biogas-derived renewable fuels is no longer biogas and is either RNG or treated biogas, depending on whether it meets pipeline specifications and is placed on a commercial pipeline.

To describe biogas-derived pipeline-quality gas, we proposed to adopt a term now in common use—renewable natural gas, or RNG. Under the proposed definition, in order to meet the definition of RNG, the product would have to have met all of the following:

- The gas must be produced from biogas,
- The gas must contain at least 90 percent biomethane content,
- The gas must meet the commercial distribution pipeline specification submitted and accepted by EPA as part of registration, and
- The gas must be designated for use to produce a biogas-derived renewable fuel.

We proposed that RNG must contain at least 90 percent biomethane content because we believed this to be consistent with many commercial pipeline specifications that we have seen submitted as part of existing registration submissions for the biogas to renewable CNG/LNG pathways. We received public comments stating that the proposed 90 percent biomethane content limit was too stringent or unnecessary because of how EPA proposed to define a batch of RNG. Some public commenters noted that commercial pipeline specifications are typically specified in methane (*i.e.,* not specific to biomethane) and that often non-renewable components are blended into RNG to meet pipeline specifications. The public commenters highlighted that it would be energy intensive to clean up biogas to meet a 90 percent biomethane threshold and that many pipeline's methane content specifications are well below the proposed level. Other public commenters noted that because of how EPA proposed to measure RNG (*i.e.,* direct measurement of biomethane using specified meters) and to define a batch of RNG (*i.e.,* by being the volume of directly measured biomethane), such a limit was unnecessary and confusing. Based on these comments, we are not finalizing the proposed 90 percent biomethane threshold in the definition of RNG.

We are finalizing as proposed to define RNG such that it only meets the

[273] 85 FR 78417–78420 (December 4, 2020).

[274] See ''Guidance on Biogas Quality and RIN Generation when Biogas is Injected into a Commercial Pipeline for use in Producing Renewable CNG or LNG under the Renewable Fuel Standard Program.'' September 2016. EPA–420–B–16–075.

definition if the gas is designated for use to produce a biogas-derived renewable fuel under the RFS program. We are finalizing this element of the definition for consistency with the regulatory requirement that such fuels be used only for transportation under the RFS consistent with the Clean Air Act. This element is important to avoid the double-counting of volumes of RNG that could be claimed as both a renewable fuel under the RFS program and as a product for a non-transportation use under a different federal or state program.

EPA's previous biogas guidance explains that biogas injected onto the commercial pipeline should meet the specific pipeline specifications required by the commercial pipeline in order to qualify as transportation fuel for RIN generation.[275] Commenters noted that our proposed definition excluded RNG that required addition of non-renewable components. Based on these comments, we are modifying our proposed definition of RNG to specify that RNG must not require removal of components to be placed into a commercial pipeline. This definition would not disqualify gas that requires addition of non-renewable components in order to meet pipeline specifications. Since the definition of RNG is based on pipeline specifications, registration submissions for RNG must include these pipeline specifications to demonstrate that the definition of RNG will be met.

Treated biogas results from processing biogas similar to RNG, but, unlike RNG, it is not intended to be placed on a commercial pipeline. We have created different regulatory provisions for treated biogas and RNG because we have different concerns regarding how to verify that they are used as transportation fuel. Treated biogas is a separate term from RNG to distinguish the different regulatory provisions.

We have incorporated the use of these new definitions in both 40 CFR part 80, subpart E and 40 CFR part 80, subpart M where applicable.

### *H. Registration, Reporting, Product Transfer Documents, and Recordkeeping*

We are finalizing with modifications the proposed compliance provisions necessary to ensure that the production, distribution, and use of biogas, RNG, and biogas-derived renewable fuels are consistent with Clean Air Act requirements under the RFS program. These compliance provisions include registration, reporting, PTDs, and recordkeeping requirements. Each of these compliance provisions is discussed below.

#### 1. Registration

Under the RFS program, biointermediate and renewable fuel producers are required to demonstrate at registration that their facilities can produce the specified biointermediates and renewable fuels from renewable biomass under an EPA-approved pathway. These producers demonstrate that they are capable of making qualifying biointermediates and renewable fuels by having an independent third-party engineer conduct a site visit and prepare a report confirming the accuracy of the producer's registration submission. These RFS registration requirements serve as an important step to ensure that only biointermediates and renewable fuels that can be demonstrated to meet the Clean Air Act requirements for producing qualifying renewable fuels are allowed into the program. We also require parties that transact RINs to register in order for them to gain access to EPA systems where RIN transactions are recorded and to submit required periodic reports, which are necessary to ensure that we can track and verify the validity of RINs.

To that end, biogas producers, RNG producers, and RNG RIN separators must register with EPA prior to participation in the RFS program. Under these registration requirements, biogas producers, RNG producers, and RNG RIN separators must submit information that demonstrates that the facilities are capable of producing biogas, RNG, or renewable CNG/LNG from renewable biomass under an EPA-approved pathway. For biogas producers and RNG producers, this information must include the feedstocks that the producer intends to use, the process through which the feedstock is converted into biogas or RNG, and any other information necessary for EPA to determine whether the biogas or RNG, was produced in a manner consistent with Clean Air Act and EPA's regulatory requirements. Such information is necessary to ensure that biogas-derived renewable fuels are produced only from qualifying biogas. Biogas producers and RNG producers must also establish a baseline volume for their respective facilities at registration. This baseline volume is intended to represent the production capacity of the facility and serve as a check for EPA and third parties on the volumes reported by a facility of biogas or RNG to help identify potential fraud. Like biointermediate production and renewable fuel production facilities, we are requiring that biogas production and RNG production[276] undergo a third-party engineering review as part of registration to have an independent professional engineer verify at registration that the facility is capable of producing biogas or RNG consistent with Clean Air Act and EPA regulatory requirements. For RNG RIN separators, we are requiring they submit a description of process and equipment used to compress RNG into renewable CNG/LNG at registration and a list of initial dispensing locations.

We are also finalizing as proposed that biogas producers and RNG producers associate with one another as part of their registrations. An association is a process where two parties establish that they are related for purposes of complying with regulatory requirements under the RFS program. Such associations are needed to track the relationships between the parties and to allow RIN generators the ability to generate RINs in EMTS. For example, under the RFS QAP, RIN generators must associate with QAP auditors in order to generate Q–RINs in EMTS. Similarly, biointermediate producers and renewable fuel producers must associate with one another in order for the renewable fuel producer to generate RINs for renewable fuels produced from biointermediates. These associations must be submitted via registration because our registration system is currently set up to track these kinds of relationships. Similarly, when biogas is used to produce a biogas-derived renewable fuel or as a biointermediate in a biogas closed distribution system, biogas producers and RIN generators must also associate with one another at registration.

It is important to note that under existing fuel quality regulations at 40 CFR part 1090 and RFS regulations at 40 CFR part 80, new registrants who require an annual attest engagement (see Section IX.K.2) must identify a third-party auditor and associate with that party via registration. To submit materials on behalf of the regulated party, any third-party auditor who is not already registered must register in accordance with existing requirements under 40 CFR parts 1090 and 80 using forms and procedures specified by EPA. For parties required to complete an annual attest engagement under biogas regulatory reform, the registration and association of third-party auditors will

[275] See "Guidance on Biogas Quality and RIN Generation when Biogas is Injected into a Commercial Pipeline for use in Producing Renewable CNG or LNG under the Renewable Fuel Standard Program." September 2016. EPA–420–B–16–075.

[276] See 40 CFR 80.1450(b)(2).

function the same because we did not propose and are not modifying the existing requirement that all parties do so. We only highlight this provision to aide affected stakeholder's understanding of how the biogas regulatory reform will work and discuss related attest engagement requirements in more detail in Section IX.K.2.

We received several comments opposed to the requirement that biogas producers directly register. Commenters discussed how this might subject small parties to liability and regulatory burdens and suggested that the QAP process effectively oversees the process. However, it is important for parties that choose to produce biogas under the RFS program to be held responsible for complying with the regulations, because the biogas producer is the party best able to demonstrate that the biogas was produced from renewable biomass under an EPA-approved pathway. This is critical for EPA's oversight and enforcement capabilities, and to ensure that fuels that are used to satisfy the statutory volume requirements are actually qualifying renewable fuel. The RFS QAP mainly provides oversight for the facilities registered under the RFS and is not a substitute for holding biogas producers that do not comply with the regulatory requirements liable. As discussed in Section IX.C, we believe that third parties will continue to help smaller entities participate in the RFS program as they currently do for other renewable fuels.

2. Reporting

Under the RFS program, we generally require reports from regulated parties for the following reasons: (1) To monitor compliance with the applicable RFS requirements; (2) To support the generation, transaction, and use of RINs via EMTS; (3) To have accurate information to inform EPA decisions; and (4) To promote public transparency. We already have reporting requirements for renewable fuels, including for renewable CNG/LNG, in 40 CFR 80.1451. We are establishing similar reporting requirements for biogas producers, RNG producers, and RNG RIN separators.

For biogas producers, we are requiring monthly batch reports that include the amount of raw biogas produced as well as the biomethane content and energy for the biogas produced at each biogas production facility. In these reports, biogas producers must also break down each batch by its verification status, by its associated pathway information (*e.g.,* D code, feedstock, and designated use), and by the party receiving the batch (*e.g.,* RNG producer).[277] The associated pathway information includes how the biogas will be used (*i.e.,* whether the biogas would be used to make renewable CNG/LNG via a closed, private pipeline system; RNG; or used as a biointermediate). This information is necessary for EPA to ensure that the amount of biogas produced corresponds to the biogas producer's registration information and serves as the basis for RIN generation for biogas-derived renewable fuels. This information is also important for the verification of RINs under the RFS QAP and for annual attest audits.

We intend to have biogas producers complete the monthly reporting requirement by entering batch reports directly into EMTS and then transferring each batch also in EMTS to a party that uses such biogas to produce a biogas-derived renewable fuel, RNG, or a biointermediate. Tracking the movement of biogas batches in EMTS between the biogas producer and the parties that use such biogas to produce biogas-derived renewable fuels, RNG, or as a biointermediate will improve the quality of information, enable better information sharing between parties, including third-party auditors, and define a structured reporting process.

For RNG producers, we are requiring quarterly reports to support verification of the amount of RNG produced from qualifying biogas and injected into the natural gas commercial pipeline system. RNG producers must report the amount and energy content of biogas used to produce RNG and the quantity of RNG that was produced and placed onto the natural gas commercial pipeline system by verification status and associated pathway. Similar to the biogas reports, these reporting requirements are necessary to demonstrate the amount of RNG produced from qualifying biogas and to describe the amount of RNG placed on the natural gas commercial pipeline system, and to help track the associated pathways and D-codes of the produced RNG. We note that these reports are intended to replace the previous reporting requirements for renewable CNG/LNG RIN generators.[278] Under biogas regulatory reform, we will no longer require that the contracts or affidavits were obtained from parties in the biogas distribution/generation chain, since this tracking will be done via EMTS. We believe this will greatly simplify the quarterly reporting requirements related to RNG when compared to the prior biogas to renewable CNG/LNG regulatory provisions.

Similar to the reporting procedure for biogas producers, RNG producers will generate RNG RINs in EMTS and transact them to parties that use the RNG as a feedstock, for process heat, or to produce renewable CNG/LNG. RNG producers would match the corresponding batch of biogas to the batch of RNG through transactions in EMTS like how RINs are currently transacted. This allows a batch of RNG to be directly connected to a corresponding amount of biogas batches within the RNG producer's EMTS holdings. This process ensures the batch information has been properly reported and transferred between parties. The reports will also serve as the basis for third-party verification and EPA audits to help ensure the validity of RNG RINs.

We are requiring that RNG RIN separators submit periodic reports related to their RNG RIN separation activities. For RNG to renewable CNG/LNG, these reports must denote which facilities/dispensers converted RNG to renewable CNG/LNG, where the renewable CNG/LNG was dispensed, and the amount of RNG that was converted to renewable CNG/LNG and dispensed. This information is necessary to help demonstrate that the RNG was converted to renewable CNG/LNG and used as transportation fuel. These periodic reports also serve as the basis for attest auditors and EPA to verify RNG RIN separation activities.

RNG RIN separators must also submit additional information related to the separation transaction in EMTS. Under the previous regulations, we established a series of codes to identify the reason that a RIN is separated, consistent with the regulatory requirements that allow for RIN separation.[279] To implement the requirements for biogas regulatory reform, we are requiring that RNG RIN separators identify in EMTS the reason they were separating an assigned RIN from RNG via new separation codes; *i.e.,* whether the RIN was separated from the RNG for conversion to renewable CNG/LNG. These parties may only separate the RIN from RNG after they have the documentation needed to demonstrate that the RNG was used as transportation fuel in the form of renewable CNG/LNG.[280] These changes to EMTS will

[277] Multiple commenters noted a difference in the preamble to the NPRM and the proposed regulations regarding whether separate batches should be generated by digester or by facility. We are finalizing that batches should be generated by facility, as discussed in RTC Section 10.5.

[278] RFS0601: Renewable Fuel Producer Supplemental report.

[279] See 40 CFR 80.1429.

[280] Note, RIN separation transactions are reported in EMTS. RNG RIN separators must report RIN

Continued

help track the use of RNG under the RFS program, which we believe will improve program oversight.

3. Product Transfer Documents (PTDs)

We are requiring product transfer documents (PTDs) for transfers of title for biogas and RNG. We have historically used PTDs to create a record trail that demonstrates the movement of product and information between various parties, as a mechanism to designate and certify regulated products as meeting EPA's regulatory requirements, and to convey specific information to parties that take custody or title to the product.[281] PTDs are important for biogas regulatory reform as they are necessary to document that qualifying biogas was transferred between biogas producers and RNG producers. EPA and third parties also review PTDs to help verify the RINs are validly generated.

For biogas title transfers, we are requiring that PTDs include information related to the transferer and transferee, the intended use of the biogas, the amount of biogas being transferred, and the date that title of the biogas was transferred. For RNG title transfers, we are requiring that PTDs include the names and addresses of the transferor and transferee, the transferor's and transferee's EPA company registration numbers, the amount of RNG being transferred, and the date of the transfer. Additionally, we are requiring that RNG producers clearly designate on the PTDs that the RNG must be used as transportation fuel. We note that the RIN PTD requirements at 40 CFR 80.1453(a) also apply to transfers of title for the RINs assigned to the RNG. For cases when RNG is transferred prior to injection into the natural gas commercial pipeline system (*i.e.,* between the RNG production facility and the injection point), we are also requiring PTDs for transfer of RNG custody that indicate that the RNG must be used for qualifying purpose. The purpose of requiring PTDs for custody transfers prior to injection into the natural gas commercial pipeline system is to create a paper trail so that third parties and EPA can audit whether the RNG claimed as injected into the pipeline was in fact injected into the natural gas commercial pipeline system. These elements of the PTDs largely mirror the elements included on the current PTD requirements for transfers of renewable fuels and biointermediates under the current RFS program in 80.1453.

separations consistent with the regulatory requirements specified in 40 CFR 80.140(d) and 80.1452.

[281] The PTD requirements for RFS are described at 40 CFR 80.1453.

4. Recordkeeping

We are finalizing as proposed recordkeeping requirements for biogas producers, RNG producers, and RNG RIN separators. The purpose of recordkeeping requirements under the RFS program is to allow verification that the renewable fuels were produced from qualifying renewable biomass, under an EPA-approved pathway, and that the renewable fuel was used as transportation fuel, heating oil, or jet fuel. These records serve as the basis for information submitted to EPA as part of registration and reporting, as well as for the basis of audits conducted by independent third parties and EPA.

For biogas producers, we are requiring records that are already required under the RFS for the production of renewable CNG/LNG from biogas. These records include information needed to show that biogas came from qualifying renewable biomass, copies of all registration information including information related to third-party engineering reviews, copies of all reports, and copies of any required testing and measurement under the RFS program.

For RNG producers, we are including recordkeeping requirements consistent with other parties that produce renewable fuels under the RFS program. Relevant to RNG production, RNG producers must maintain records indicating how much biogas was received at their facility from a registered biogas producer, records demonstrating how much biogas was converted to RNG, and records showing the amount of non-renewable content added to ensure that applicable pipeline specifications are met. For RNG injection, RNG producers are required to maintain records showing the date of injection and the volume and energy content of the RNG injected into the natural gas commercial pipeline system.[282] For RNG RIN generation, RNG producers must maintain records related to the generation of RINs in accordance with 40 CFR 80.1454(b). These recordkeeping requirements are necessary to ensure that the RNG was produced and injected in a manner consistent with CAA requirements and applicable regulatory requirements, and that the appropriate number of RINs was generated for the RNG injected into the natural gas commercial pipeline system.

[282] For specific cases where RNG that is trucked to an interconnect, we are proposing the RNG producer measure when loading and unloading each truck.

Since EPA will be tracking the movement of assigned RNG RINs in EMTS, we no longer require that the RIN generator (*i.e.,* RNG producer under biogas regulatory reform) maintain records related to the contractual arrangements for the sale and transfer of RNG to parties that distribute the RNG to the end user. These records will no longer be needed since EMTS will memorialize the necessary information pertaining to the transfer of the assigned RINs.

We are also requiring that RNG RIN separators maintain records related to their RNG RIN separation activities. For RNG to renewable CNG/LNG, this includes information related to the location where the RNG was converted into renewable CNG/LNG, as well as the date, location, and amount of dispensed CNG/LNG. The recordkeeping requirements related to demonstrating that RNG was used as transportation fuel were previously maintained by the RIN generator but now must be maintained by the RNG RIN separator. These records are necessary to ensure that RNG is used as transportation fuel, and we believe that it is most appropriate to require that the party best positioned to demonstrate that the RNG is used as transportation fuel maintain the records.

### *I. Testing and Measurement Requirements*

We are finalizing specific testing and measurement procedures for biogas and RNG. Due to the value of RINs and the contribution that that value can make to company revenue, parties have clear incentives to manipulate testing and measurement results to appear to have produced more biogas, RNG, and biogas-derived renewable fuels than they actually did. By establishing clear and consistent testing and measurement requirements, we can ensure the validity of RINs and a level playing field for RIN generators.

For the measurement of biogas and RNG, we are finalizing the incorporation of relevant portions of the previously published guidance into the regulations.[283] Under the guidance, we allowed for parties to submit as part of their registrations whether they were using in-line gas chromatography (GC) meters or an alternative sampling protocol for measurement of biogas. In this action, we are also allowing an alternative to continuous measurement,

[283] "Guidance on Biogas Quality and RIN Generation when Biogas is Injected into a Commercial Pipeline for use in Producing Renewable CNG or LNG under the Renewable Fuel Standard Program" See document ID: EPA–420–B–16–075.

specifying a specific standard for GC meters, and requiring measurement for both biogas and RNG.

Multiple commenters raised concerns about the proposed measurement devices. They requested that EPA allow other types of measurement devices and allow use of the manufacturers' operating procedures in lieu of EPA's proposed standardized measurement techniques. However, federal regulations based on the National Technology Transfer and Advancement Act (NTTAA) state that agencies should give preference to standardized measurement techniques.[284] Given that there are standards for measurement techniques that can be used in the measurement of methane concentration and flow of biogas and RNG, we do not believe it is appropriate to allow for the use of manufacturers' operating procedures or to allow parties to provide documentation to EPA when standards for such measurement exist. The appropriateness of using other techniques mentioned by the commenters depends on whether a standard meets the requirements. Commenters did not provide standards for the alternative measurement devices that they recommended EPA allow, although EPA did find one standard that is sufficient which is for thermal mass flow measurement devices and is therefore allowing those devices under the program. The standards for measurement that we are finalizing are as follows:

- API MPMS 14.3.1, API MPMS 14.3.2, API MPMS 14.3.3, and API MPMS 14.3.4: These standards describe the measurement of gaseous flow by orifice meters for use in biogas production and RNG production facilities.
- API MPMS 14.12: This standard describes measurement of gaseous flow by vortex meter for use in biogas production and RNG production facilities.
- ASTM D7164: This standard describes measurement of methane concentration by gas chromatogram for use in biogas production and RNG production facilities.
- EN 17526: This standard describes how to measure gaseous flow by thermal mass flow meter for use in biogas and RNG production facilities.

Similarly, we are also incorporating into the regulations part of the guidance related to analytical testing for the registration of biogas and RNG for use in the production of a biogas-derived renewable fuel.[285] To balance the need for timely registration with our need to ensure product quality and to inform future regulations, we are finalizing the requirement that RNG producers need to submit certificates of analysis from an independent laboratory in its three-year engineering reviews, but not at initial registration.

To summarize the requirements we are finalizing, in all engineering reviews for facilities upgrading biogas to RNG, an RNG producer must supply specifications for the natural gas commercial pipeline system into which the RNG will be injected. The pipeline specifications must contain information on all parameters regulated by the pipeline (*e.g.,* hydrogen sulfide, total sulfur, carbon dioxide, oxygen, nitrogen, heating content, moisture, and any other available data related to the gas components). Additionally, in all three-year engineering review updates for facilities upgrading biogas to RNG, an RNG producer must supply the following:

- A certificate of analysis (COA) for a representative sample of the biogas produced at the digester or landfill.
- A COA for a representative sample of the RNG prior to the addition of any non-renewable components.
- A COA for a representative sample of the RNG after blending with non-renewable components (if the RNG is blended with non-renewable components prior to injection into a pipeline).
- Summary table with the results of the three COAs and the pipeline specifications (converted to the same units).

We had proposed that facilities supply documentation of any waiver provided by the commercial distribution pipeline for any parameter of the RNG that does not meet the pipeline specifications, if applicable. Based on comments, we are no longer requiring that such waivers be supplied at registration. Instead, we are requiring parties to keep records of such waivers so that EPA can determine whether RNG producers brought RNG up to pipeline specifications consistent with EPA's regulatory requirements.

We are finalizing as proposed that the RNG producers must include on the COAs submitted as part of a three-year engineering review update major and minor gas components (*e.g.,* methane, carbon dioxide, nitrogen, oxygen, heating value, relative density, moisture, and any other available data related to the gas components), hydrocarbon analysis, and trace gas components (*e.g.,* hydrogen sulfide, total sulfur, total organic silicon/siloxanes, moisture, etc.), plus any additional parameters and related specifications for the pipeline being used. We are also specifying methods that must be used when measuring biogas properties. These standards are based on methods used for these measurements which have been submitted to us in the past and which we believe provide sufficient accuracy. The standards we are codifying for biogas and RNG measurement for three-year engineering review update analysis are the following:

- ASTM D3588: This method describes how to calculate heating value and relative density.
- ASTM D4888: This method describes how to measure moisture content.
- ASTM D5504: This method describes how to measure hydrogen sulfide and other sulfur compounds.
- ASTM D6866: This method measures biogenic carbon.
- ASTM D8230: This method describes how to measure siloxanes.
- EPA Method 3C: This method describes how to measure methane, carbon dioxide, nitrogen, and oxygen.
- API MPMS 14.1: This method describes how to obtain representative samples.

We also note in the guidance that parties must keep the COAs, pipeline specifications, and any measurement-related RIN generation components under the recordkeeping requirements of 40 CFR 80.1454. As part of the RFS program's third-party oversight provisions, the guidance recommends that third-party engineers review conformance with applicable recordkeeping requirements as part of their engineering reviews while third-party auditors review conformance with these recordkeeping requirements pursuant to the RFS QAP. We are finalizing as proposed that RNG producers must keep testing and measurement records of biogas and RNG and that third-party auditors must verify this information as part of QAP, if applicable, as mentioned in the guidance.[286]

We are also finalizing as proposed additional measurement requirements

[284] 15 CFR 287.4(f).

[285] ''Guidance on Biogas Quality and RIN Generation when Biogas is Injected into a Commercial Pipeline for use in Producing Renewable CNG or LNG under the Renewable Fuel Standard Program'' See document ID: EPA–420–B–16–075.

[286] ''Guidance on Biogas Quality and RIN Generation when Biogas is Injected into a Commercial Pipeline for use in Producing Renewable CNG or LNG under the Renewable Fuel Standard Program'' See document ID: EPA–420–B–16–075.

for RNG that is trucked to a gas pipeline interconnect. In this situation, RNG producers must measure RNG flow and energy content of biomethane both on loading into and unloading from the truck. We find that this requirement is necessary to ensure that RINs are only generated from renewable biomass.

*J. RFS QAP Under Biogas Regulatory Reform*

Consistent with how QAP was treated under the previous biogas provisions, we are not requiring that biogas producers and RNG producers participate in the RFS QAP. We believe these biogas regulatory reforms will address the issues of double counting as discussed in Section IX.A.4.b, such that a requirement that biogas producers and RNG producers participate in the RFS QAP is not necessary.

While we are not requiring RFS QAP participation, for parties that choose to participate in QAP under the updated biogas program, both the biogas producer and the RNG producer must be audited by the same independent third-party auditor in order to generate a Q–RIN for RNG. In the NPRM we proposed additional elements that a QAP auditor would have to verify under biogas regulatory reform consistent with the proposed regulatory requirements.[287] These new QAP elements for RNG producers included requirements that the QAP auditor must: [288]

• Verify that the sampling, testing, and measurement of RNG is consistent with the new regulatory requirements.

• Verify that RINs were assigned correctly.

• Verify that RINs were separated and retired correctly.

• Verify that the RNG was injected into a natural gas commercial pipeline system.

• Verify that RINs were not generated on non-renewable components added to RNG prior to injection into a natural gas commercial pipeline system.

These new QAP elements are necessary for QAP auditors to ensure that RNG and RNG RINs are produced and generated, respectively, consistent with the biogas regulatory reform provisions and, in addition to the generally applicable QAP elements at 40 CFR 80.1469, will provide a robust verification scheme to help ensure that RINs generated for RNG are valid. Therefore, we are finalizing them as proposed.

We note that, under this action, the parties that transact the assigned RNG RIN and the RNG RIN separator do not need to be included as part of the RFS QAP. This approach is consistent with the current regulatory treatment of RINs generated for ethanol and biodiesel, and we are not modifying how the RFS QAP considers RIN separations in this action. We note that, as described in Section IX.K.2, we are requiring that RNG RIN separators undergo annual attest engagements, which we believe should provide sufficient third-party oversight to ensure that RNG RINs are separated consistent with the biogas regulatory reform provisions.

Several commenters suggested that instead of finalizing the proposed biogas regulatory reform provisions, EPA should require QAP participation for parties that generate RINs for biogas to CNG/LNG. While we believe that QAP participation can provide added assurance for parties that transact RINs generated for biogas to CNG/LNG, the QAP is not a substitute for the biogas regulatory reform provisions. EPA cannot implement through QAP the modified measurement, reporting, and recordkeeping requirements that are necessary to ensure that qualifying biogas is used to produce biogas-derived renewable fuels or address our double-counting concerns in a situation where biogas may be used for multiple purposes under the RFS program. These requirements must be imposed on the parties that produce, distribute, and use biogas, RNG, and biogas-derived renewable fuels because those parties are best positioned to demonstrate compliance with the applicable statutory and regulatory requirements. The QAP auditor's role is to verify that the applicable regulatory requirements are met, not serve as a substitute for the compliance and enforcement provisions that compose biogas regulatory reform designed to ensure that qualifying biogas is produced and used to generate valid RINs. As we articulated in Section IX.A, we are modifying the compliance and enforcement mechanisms under the previous biogas provisions to address concerns with double counting to ensure that RINs generated from biogas meet Clean Air Act and EPA regulatory requirements.

Commenters also failed to explain how QAP participation would effectively address any of EPA's concerns with oversight after we have allowed biogas and RNG to be used for multiple uses under the RFS program. As noted in the NPRM,[289] we believe the previous biogas provisions were ill-suited for situations where biogas/RNG could have multiple uses and that the increased flexibility in the program would require additional oversight to ensure that biogas/RNG was not double-counted and generating invalid RINs. QAP cannot effectively oversee this situation because individual auditors would only verify a small portion of the production/distribution system as part of their verification. Only through creating effective, systemwide tracking can such verification occur. Our biogas regulatory reform provisions will use EMTS to track the movement of biogas and RNG from production until ultimate use. QAP auditors and EPA can then use this tracking information to verify that double-counting did not occur.

*K. Compliance and Enforcement Provisions and Attest Engagements*

We are finalizing as proposed compliance and enforcement provisions for biogas-derived renewable fuels similar to the existing compliance and enforcement provisions under the RFS program. Under the RFS program, these provisions serve to deter fraud and ensure that EPA can effectively enforce when noncompliance occurs, and the compliance and enforcement provisions for biogas-derived renewable fuels will serve the same purposes. We discuss the specific provisions below.

1. Prohibited Actions, Liability, and Invalid RINs

In order to deter noncompliance, the regulations must make clear what acts are prohibited, who is liable for violations, and what happens when biogas-derived RINs are found to be invalid. To this end, we are finalizing as proposed provisions that establish: (1) Prohibited actions relating to the generation of RINs from biogas-derived renewable fuels; (2) How biogas producers, RNG producers, and RIN generators for RNG will be held liable when RINs from biogas-derived renewable fuels are determined to be invalid; (3) How biogas producers and RNG producers may establish affirmative defenses; and (4) Provisions related to the treatment of invalid RINs from biogas-derived renewable fuels. Many of these provisions are similar to provisions under the existing RFS program and EPA's fuel quality programs in 40 CFR part 1090.

a. Prohibited Actions

The RFS program regulations enumerate specific prohibited acts under the RFS program. In our recent Fuels Regulatory Streamlining Rule, we consolidated the multiple prohibited acts statements in the various fuel quality provisions sections of 40 CFR part 80 into a single prohibition against causing, or causing someone else to,

[287] See 87 FR 80737–80738 (December 30, 2022).

[288] See 40 CFR 80.180(c).

[289] 87 FR 80693.

violate any requirement of the part.[290] For biogas regulatory reform, we are adopting a prohibited act that mirrors the consolidated prohibited acts provision from the Fuels Regulatory Streamlining Rule, and specify that any person who violates, or causes another person to violate, any requirement in the subpart for biogas-derived renewable fuels, *i.e.,* 40 CFR part 80, subpart E, is liable for the violation. Consolidation of the prohibited actions is not meant to alter the scope of prohibited actions, but instead provides more clarity to the regulated community regarding what actions are prohibited.

b. Liability Provisions for Biogas, RNG, Biogas-Derived Renewable Fuels, and RINs generated for RNG and Biogas-Derived Renewable Fuels

We are finalizing as proposed liability provisions similar to the liability provisions in other EPA fuels programs, including the existing RFS program and the recently finalized biointermediates rule. Specifically, we are requiring that when biogas, RNG, biogas-derived renewable fuels, or RINs from RNG or a biogas-derived renewable fuel are found to be in violation of regulatory requirements, the biogas producer, the RNG producer, the biogas-derived renewable fuel producer, and the person that generated RINs from RNG or a biogas-derived renewable fuel will all be liable for the violation. Consequently, RIN generators for biogas-derived renewable fuels are ultimately responsible for ensuring that any biogas or RNG used to produce the fuel complies with the regulations. The description of feedstocks and processes in registration materials accepted by EPA does not constitute a determination by EPA that the subsequent feedstocks and processes used subsequent to the registration are consistent with the RFS regulations. Rather it merely represents that the information provided at registration would allow for proper RIN generation. The responsibility of ensuring compliance with applicable requirements on a continuing basis for biogas, RNG, and RINs generated from RNG and biogas-derived renewable fuel rests with all parties in the biogas disposition/generation chain.

As noted above, this approach to liability has been used extensively in other 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. If upstream parties, such as RNG producers, are concerned about downstream non-compliance, they can take advantage of the affirmative defense provisions if all of the criteria are met.

We note that the current RFS regulations include provisions for EPA to take certain administrative actions in cases where a regulated party has been found to engage in a prohibited practice under the RFS regulations. First, under 40 CFR 80.1450(h) EPA may deactivate a company registration in cases where a party has failed to comply with applicable regulatory requirements. The regulations provide that EPA will notify the party of the compliance issue, and the party has 30 days from the date of the notification to correct the issue before EPA may deactivate the party's registration. However, in cases where the party's actions compromise public health, public interest, or public safety, EPA may deactivate the registration of the party without prior notice to the party. This would likely apply in cases where a party is found to be generating invalid or fraudulent RINs. Second, EPA may administratively revoke an RFS QAP plan for cause. The existing regulation at 40 CFR 80.1469(e)(4) specifies that EPA may revoke a QAP plan "for cause, including, but not limited to, an EPA determination that the approved QAP has proven to be inadequate in practice." Furthermore, the regulation at 40 CFR 80.1469(e)(5) specifies that "EPA may void *ab initio* its approval of a QAP upon the EPA's determination that the approval was based on false information, misleading information, or incomplete information, or if there was a failure to fulfill, or cause to be fulfilled, any of the requirements of the QAP."

Under biogas regulatory reform, these existing provisions for administrative action will apply like they do currently under the RFS program. We would intend to deactivate registrations in cases where parties in the biogas disposition/generation chain have failed to meet their regulatory requirements or when it is identified that the party has willfully generated invalid or fraudulent RINs. The consequences of deactivation of a party in the biogas disposition/generation chain (*i.e.,* a biogas producer, RNG producer, or RNG RIN separator) would result in the prohibition of the generation of RINs from any affected biogas, RNG, or biogas-derived renewable fuel from the party whose registration was deactivated. Similarly, if EPA has approved a QAP plan for a biogas-derived renewable fuel and EPA revokes the QAP plan, the RIN generator previously under that QAP plan would not be able to generate verified RINs for that fuel. We note that these administrative actions would be in addition to any civil penalties. We believe that in combination with the prohibited actions, liabilities, and provisions for dealing with invalid RINs from biogas-derived renewable fuel being finalized in this rule, regulated parties in the biogas disposition/generation chain would have a strong incentive to comply with the biogas regulatory reform provisions.

c. Affirmative Defenses

We are finalizing as proposed that biogas producers and RNG producers may establish affirmative defenses to certain violations if the biogas producer or RNG producer meets all elements specified to establish an affirmative defense. We allow for affirmative defenses in the RFS program and in our fuel quality program under 40 CFR part 1090 in cases where a party did not cause or contribute to the violation or financially benefit from the violation. We are allowing biogas producers to establish an affirmative defense so long as all the following are met:

- The biogas producer or any of the biogas producer's employees or agents, did not cause the violation.
- The biogas producer did not know or have reason to know that the biogas, RNG, or RINs were in violation of a prohibition or regulatory requirement.
- The biogas producer has no financial interest in the company that caused the violation.
- If the biogas producer self-identified the violation, the biogas producer notified EPA within five business days of discovering the violation.
- The biogas producer submits a written report to EPA within 30 days of discovering the violation, which includes all pertinent supporting documentation describing the violation and demonstrating that the applicable elements of this section were met.
- The biogas producer conducted or arranged to be conducted a quality assurance program that includes, at a minimum, a periodic sampling and testing program adequately designed to ensure its biogas meets the applicable requirements to produce the biogas.
- The biogas producer had all affected biogas verified by a third-party auditor under an approved QAP plan.
- The PTDs for the biogas indicate that the biogas was in compliance with the applicable requirements while in the biogas producer's control.

For RNG producers, we are finalizing as proposed analogous requirements to

[290] See 85 FR 29034, 29075 (May 14, 2020); 40 CFR 1090.1700.

establish an affirmative defense except that, instead of relating to biogas producers, the elements relate to RNG producers. We believe these elements to establish an affirmative defense will allow RNG producers to avoid liability only in cases where they could not reasonably be expected to know that a violation took place; for example, if an RNG RIN separator separated RINs improperly.

We are also finalizing as proposed that RNG producers and biogas-derived RIN generators may not establish an affirmative defense against violations when the RNG or biogas-derived renewable fuel, respectively, is found to be in violation. Under the RFS program, the RIN generator is always responsible for the validity of the RIN. As such, biogas-derived renewable fuel RIN generators will not have the ability to establish an affirmative defense for biogas-derived renewable fuels and RINs generated for such fuels. We expect these parties, like all RIN generators under the RFS program, to diligently ensure that other parties that are part of the biogas distribution/generation chain are meeting their regulatory requirements. Similarly, when the RNG producer produces RNG and generates a RIN for such RNG, the RNG producer will not be able to establish an affirmative defense for the RNG or RNG RINs.

d. Invalid RINs

We are finalizing as proposed provisions similar to the existing RFS regulations to address the treatment of invalid RINs generated for RNG and biogas-derived renewable fuels. Under biogas regulatory reform, if a RIN generated for RNG or a biogas-derived renewable fuel is identified as potentially invalid by any party (*e.g.,* the RIN generator, an independent third-party auditor, or EPA), certain notifications and remedial actions will be required to address the potentially invalid RIN. These provisions are necessary to ensure that RINs represent biogas-derived renewable fuels that were produced from renewable biomass under an EPA-approved pathway and used as transportation fuel.

We are also finalizing as proposed provisions that require biogas and RNG producers to notify the next party in the biogas disposition/generation chain if they become aware that inaccurate amounts of biogas or RNG were transferred to that party. In addition, any person must notify EPA within five business days of discovery if they become aware of any biogas or RNG producers taking credit for the sale of the same volumes of biogas/RNG to multiple downstream parties. These provisions are necessary to help prevent the generation of invalid RINs by ensuring that parties in the biogas disposition/generation chain are informing all affected parties of issues when they arise.

2. Attest Engagements

We are finalizing as proposed attest engagement provisions similar to the attest engagement provisions in other EPA fuels programs, including the existing RFS program and the recently finalized biointermediates rule. These provisions are designed to ensure compliance with the regulatory requirements, and this action simply extends those requirements to the newly regulated parties under biogas regulatory reform. Specifically, we are finalizing as proposed that biogas producers, RNG producers, and RNG RIN separators separately undergo an annual attest engagement. Annual attest engagements are annual audits of registration information, reports, and records to ensure compliance with regulatory requirements. Under our fuel quality and RFS programs, we require that attest engagements be performed by an independent third-party certified professional accountant that notifies EPA of any discrepancies they identify in their prepared report. The audited parties typically correct areas identified by the attest auditor, and we review the reports for areas of concern that need to be addressed in future actions. We have a long history of successfully employing annual attest engagements to help ensure integrity of our fuel quality and RFS programs, and we believe that attest engagements are an important component of third-party oversight of biogas-derived renewable fuels.

Attest engagements for biogas producers involve an audit of underlying records (including measurement records and PTDs), reports, and registration information (including the third-party engineering review report) for batches of biogas. These attest engagement procedures for biogas producers help ensure that biogas is generated from qualifying feedstocks and consistent with EPA's regulatory requirements.

Attest audits for RNG producers involve additional procedures that are specific to the production and injection of RNG into the natural gas commercial pipeline system. These provisions involve verifying that records of the measurement of RNG injection are consistent with the measurement requirements for RNG described in Section IX.I and verifying that pipeline injection statements match the amount of RNG reported by RNG producers in quarterly reports. Attest auditors must also confirm that the correct number of RINs were generated in EMTS as compared to the underlying records. The purpose of these new attest engagement procedures for RNG producers is to help ensure that RNG RINs are validly generated consistent with EPA's regulatory requirements for RNG.

We are also requiring specific annual attest engagement procedures to verify RNG RIN separation. These annual attest engagement procedures are in addition to those currently required for RINs separated under 40 CFR 80.1464. Specifically, an independent attest auditor must obtain the underlying records for reported information regarding an RNG RIN separator's operations and ensure that the RNG RIN separator has only separated RNG RINs in a manner consistent with their ability to demonstrate that RNG was used as transportation fuel. Similar to other annual attest engagement procedures under EPA's fuels program, issues identified by the independent attest auditor are required to be flagged in the annual attest engagement report. These annual attest engagement provisions are necessary to ensure that RNG RINs are only separated when consistent with applicable regulations.

The attest engagements for all parties under biogas regulatory reform follow the same general requirements for other attest engagements under EPA's other fuel programs.[291] In their registration information, parties must identify their independent attest auditors, and their independent attest auditors must electronically submit annual attest engagement reports directly to EPA using forms and procedures prescribed by EPA. In addition, an independent auditor (*i.e.,* a CPA without any interest in the audited party) must conduct the audit on a representative sample of information, prepare the annual attest engagement report detailing any discrepancies or findings from the audit, and submit the report to EPA by the annual June 1st deadline. Attest engagements are appropriate for parties involved in the generation of RINs for biogas-derived renewable fuels as they serve to maintain consistency across the three regulated parties and serve as valuable third-party oversight.

*L. RNG Used as a Feedstock*

We are finalizing as proposed provisions to address situations in which RNG is used as a feedstock to make biogas-derived renewable fuel

[291] See 40 CFR 80.1464 and 1090.1800.

other than renewable CNG/LNG. Specifically, renewable fuel producers must retire the RINs assigned to a given volume of RNG prior to using that volume to produce biogas-derived renewable fuels. When RNG is used as a feedstock to produce a biogas-derived renewable fuel, the applicable RIN generation procedures would vary depending on what fuel is made from the RNG. For example, if a renewable fuel producer were to use RNG as a feedstock to produce hydrogen, the renewable fuel producer would retire any RINs assigned to the volume of RNG and then generate new RINs for the hydrogen so long as the hydrogen met all other applicable regulatory requirements to qualify as a renewable fuel.

We believe this approach allows for multiple uses of RNG without imposing strict limits on the parties that produce or distribute RNG. By assigning RINs to the RNG injected into the natural gas commercial pipeline system and using EMTS to track the transfer of the assigned RINs between parties that produced the RNG and those that use the RNG, we believe we can provide flexibility in the use of RNG while maintaining adequate oversight. We believe requiring the RNG RINs to be retired sufficiently mitigates concerns with possible double counting of the RNG, *i.e.,* a party could not generate an additional RIN or allotment for the RNG unless any assigned RINs were first retired.

We received a significant number of public comments that supported allowing RNG to be used as a feedstock to produce biogas-derived renewable fuels other than renewable CNG/LNG. However, some of these commenters also suggested that the proposed biogas regulatory reform provisions were not needed to allow this activity. For reasons more thoroughly discussed in Section IX.A.4 and in the RTC document, the biogas regulatory reform provisions are necessary to ensure that RINs generated for biogas-derived renewable fuels are valid and to allow biogas and RNG to be used as a biointermediate or as a feedstock, respectively, under the RFS program. Without the biogas regulatory reform provisions, we could not adequately oversee the program, and without clear regulatory requirements and compliance mechanisms to appropriately account for the production, distribution, and use of biogas and RNG, there would be increased opportunities to double-count biogas/RNG.

*M. RNG Imports and Exports*

For imported RNG, we are maintaining, as proposed, the existing regulatory structure of the RFS whereby either the RNG importer or the producer of the foreign RNG may generate RINs. Under the previous biogas provisions, approximately 10 percent of D3 RINs are generated from imported Canadian RNG. Under this action, we are maintaining the flexibility of allowing either the foreign renewable fuel producer (in this case, the foreign RNG producer) or an importer of foreign RNG may generate RINs. A difference between the new regulations and the previous biogas provisions is that instead of any foreign party in the biogas distribution/generation chain being allowed to generate RINs, only a foreign RNG producer or RNG importer may generate the RIN. We do not believe these approach changes will significantly affect which parties currently generate RINs for Canadian RNG because to date only the RNG importer has generated RINs.

We note that consistent with the treatment of any foreign party that generates RINs under the RFS program, where a foreign RNG producer generates a RIN, that foreign producer must satisfy the additional regulatory requirements at 40 CFR 80.1466, which include submitting to U.S. jurisdiction, complying with inspection requirements, and posting a bond. We also note that any foreign party that owns RNG RINs must also meet the additional regulatory requirements for foreign RIN owners at 40 CFR 80.1467.

We are treating exports of RNG similarly to exports of renewable fuel under the RFS program because like when a renewable fuel that was exported, exported RNG would no longer be eligible for use as transportation fuel in the covered location thereby invalidating any RINs generated for the RNG. We have become increasingly aware that, due to demands abroad for pipeline quality natural gas and RNG, some parties may wish to export RNG. Under this action, since a RIN is generated for RNG at the point of injection into a natural gas commercial pipeline system, any party that exports the RNG outside of the covered location incurs an exporter RVO under 40 CFR 80.1430 and is required to satisfy that RVO by retiring the appropriate number and type(s) of RINs.

*N. Biogas/RNG Storage Prior to Registration*

We are finalizing as proposed provisions that address biogas or RNG that is produced and stored prior to EPA's acceptance of a biogas or RNG producer's registration submission. We proposed that biogas or RNG may be stored on site (*i.e.,* at a storage facility co-located at the biogas or RNG production facility [292]) prior to EPA's acceptance of a registration submission, provided that certain conditions are met. In order to ensure equal treatment of all parties, we also proposed that these storage provisions also apply to all other biointermediates and renewable fuels under the RFS program.

We received multiple comments on these proposed provisions. Several commenters stated that not allowing RINs to be generated for RNG stored off-site prior to EPA's acceptance of a registration would impose a burden on stakeholders due to, among other things, the long amount of time it takes EPA to process and accept registration requests In the NPRM, we explained that we believed the streamlined registration requirements for RNG producers should greatly decrease the time necessary to process registrations and thus eliminate the need for offsite storage prior to EPA acceptance of registration. After reviewing the comments, we continue to believe this to be the case, as discussed more fully in the RTC document. Consequently, we are finalizing as proposed that any biogas or RNG which is produced and stored prior to EPA's acceptance of a biogas or RNG producer's registration submission must be stored on-site to participate in RFS. What follows is background and detail about what we are finalizing.

Under the RFS1 program, we issued guidance [293] stating that parties may assign RINs for renewable fuels that had left the renewable fuel production facility prior to EPA acceptance of registration because the RFS1 regulations required that RINs be assigned to renewable fuels at the point of production but did not specifically define what ''point of production'' meant. We took this approach under RFS1 because the program did not require that the renewable fuel be produced under an EPA-approved pathway (*i.e.,* the renewable fuel qualified by virtue of meeting the

[292] ''Facility'' is defined at 40 CFR 80.1401 to mean ''all of the activities and equipment associated with the production of renewable fuel starting from the point of delivery of feedstock material to the point of final storage of the end product, which are located on one property, and are under the control of the same person (or persons under common control).''

[293] Questions and Answers on the Renewable Fuel Standard Program. Page 7. *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1001T9Z.pdf.*

definition of ''renewable fuel'' under the RFS1 program).

Under the RFS2 program, in general, EPA does not allow parties that produce renewable fuels to generate RINs for renewable fuel that has left the control of the renewable fuel producer prior to EPA acceptance of the renewable fuel producer's registration. We have not allowed this because of the possibility that EPA may determine that the fuel was not produced consistently with EPA's regulatory requirements and, therefore, may not be eligible for RIN generation. In contrast, however, we had allowed parties to generate RINs for biogas and RNG that was produced prior to EPA acceptance of the RIN generator's registration and was stored offsite, provided several conditions were met. First, the biogas/RNG must have been produced after the third-party engineer conducted the site visit as described in 40 CFR 80.1450(b)(2). Second, the biogas/RNG must have been produced consistent with the requirements of an EPA-approved pathway. Third, the RIN generator must not have changed the facility after the site visit by the third-party engineer. We had allowed this greater flexibility to allow biogas/RNG to be stored offsite prior to registration for pathways converting biogas to renewable CNG/LNG in large part due to the length of time it has taken EPA to review and accept registrations as a result of the previous registration requirements. However, this flexibility has hindered our ability to verify the validity of RIN generation for stored biogas/RNG. From our experience implementing biogas pathways, allowing RNG to be stored offsite has posed challenges when overseeing the production of RNG, since the production of RNG from the facility would often not match the number of RINs generated. The information used to generate the RINs was often different from the information used to demonstrate RNG production for the month. The main reason this information did not align under the previous biogas provisions was likely because RNG is typically stored for an undisclosed period of time. Because of how difficult it is to track discrete volumes of RNG that are claimed for RIN generation, production and use information rarely matched up, and the only way to compare RNG production information with RNG use information was to review all of the underlying records for every party in the entire distribution system over the entire period, which could involve the collection and evaluation of hundreds of thousands of records for the production, transfer, and use of each discrete volume of biogas/RNG since the beginning of the program, *i.e.,* 2014. By disallowing storage prior to registration, we can fully utilize the RIN assigned to RNG volumes to track the production and use of RNG and eliminate the risk of noncompliant, stored RNG generating RINs.

As explained in Section X.H.4, as part of biogas regulatory reform we are no longer requiring that biogas and RNG producers demonstrate that there are contracts between each party in the biogas distribution/generation chain in order to demonstrate transportation use. This will streamline registration of facilities, so we believe it is no longer appropriate to allow for RINs to be generated for biogas/RNG produced and stored offsite of the biogas/RNG production facility prior to EPA acceptance of the biogas and RNG producer's registrations. Also, as discussed in Section IX.I, we are further streamlining the registration requirements by no longer requiring RNG producers to supply COAs for biogas and RNG at initial registration. The removal of this COA requirement at initial registration will likely further reduce the amount of time it will take RNG producers to be registered.

We are, however, continuing to allow for the storage onsite of biogas/RNG, consistent with other renewable fuels and biointermediates, produced prior to EPA acceptance of a registration submission if certain conditions are met. Specifically, we are allowing for storage onsite when all of the following conditions are met:

- The stored biogas, RNG, biointermediate, or renewable fuel was produced after an independent third-party engineer has conducted an engineering review for the renewable fuel production or biointermediate production facility.
- The stored biogas, RNG, biointermediate, or renewable fuel was produced in accordance with all applicable regulatory requirements under the RFS program.
- The biogas producer, RNG producer, biointermediate producer, or renewable fuel producer made no change to the facility after the independent third-party engineer completed the engineering review.
- The stored biogas, RNG, biointermediate, or renewable fuel was stored at the facility that produced the biogas, RNG, biointermediate, or renewable fuel.
- The biogas producer, RNG producer, biointermediate producer, or renewable fuel producer maintains custody and title to the stored biogas, RNG, biointermediate, or renewable fuel until EPA accepts the biogas or RNG producer's registration.

These conditions are necessary for biogas/RNG to be stored onsite prior to registration to ensure that RINs are not generated for fuels that fail to meet the applicable Clean Air Act and regulatory requirements for the production of renewable fuels. We believe that so long as the biogas or RNG producer has had a third-party engineer confirm that the facility could produce products consistent with the applicable RFS regulatory requirements and so long as the producer does not modify their facility, the biogas and RNG produced at these facilities should be eligible to generate RINs. These products have to be produced in accordance with the applicable regulatory requirements. We are requiring that the biogas or RNG producer maintain custody of the product because once the product has left its facility, the producer would be less able to remedy issues with the product; this could also result in other parties downstream becoming liable for the product should it not meet applicable regulatory requirements. After EPA has accepted the biogas or RNG producer's registration, the stored products could then be used under the RFS program.

### *O. Single Use for Biogas Production Facilities*

To minimize program complexity and avoid the double-counting of biogas, we are also finalizing as proposed provisions to govern the use of biogas from a biogas production facility. Under these provisions, biogas producers are limited to supplying biogas or treated biogas for a single use (*e.g.,* RNG, renewable CNG/LNG, or to produce a biointermediate). We understand that in real-world applications there may often not be a perfect match between biogas production capacity and the quantity of biogas for a particular use. However, limiting biogas from each biogas production facility to a single use serves the goals of minimizing program complexity and safeguarding against double counting by eliminating the opportunity for double counting in the first place.

We received comments asking that EPA not finalize this proposed condition. Commenters stated that imposing such a condition would preclude significant volumes of biogas from being used at biogas production facilities that had projects that could supply biogas for multiple uses under the RFS program, especially if EPA finalized the eRINs proposal. Furthermore, some commenters suggested that EPA's condition related to a single biogas use precluded the use of biogas for purposes outside of the RFS program.

While we appreciate commenters' perspectives, we have concluded that retaining the proposed condition on single use is necessary given the expansion of the biogas program we are also finalizing in this rule. Allowing only a single use of biogas under the RFS program will significantly reduce the ability for parties to double count biogas for purposes of RIN generation under the RFS program. Were we to allow for multiple uses from a single facility, we would need more enhanced compliance and enforcement mechanisms than were proposed in order to adequately oversee the additional complexity. We intend to monitor the effects of the single use limitation on biogas production facilities and may consider ways to permit multiple uses of biogas at a single facility under the RFS program after we have more experience implementing the new, expanded biogas program.

In response to commenters concerns that we are limiting the ability for biogas producers to supply biogas for purposes outside of the RFS, we are clarifying that parties may use biogas for purposes outside of the RFS program; *i.e.,* the condition on the single use of biogas at a biogas facility only applies to a single use under the RFS program. We discuss related public comments and respond more thoroughly in RTC Section 10.

### *P. Requirements for Parties That Own and Transact RNG RINs*

We are finalizing as proposed the requirement that parties that solely transact assigned RNG RINs (*i.e.,* parties that transact RNG RINs but that do not generate or separate the RNG RINs) must comply with all current regulatory requirements for owning and transacting RINs under the RFS program. The sole difference is that only a party that is a registered RNG RIN separator and has demonstrated that the RNG has been used as renewable CNG/LNG will be allowed to separate the RNG RIN. In other words, parties that simply transact assigned RNG RINs are not allowed to separate RINs, and we intend to design EMTS to prevent them from doing so. As described in more detail in Section IX.H.4, this provision is necessary to ensure that RNG is used as transportation fuel consistent with the CAA and applicable regulatory requirements.

Except for the limitation on RNG RIN separation, we note that we are not otherwise modifying the requirements for parties that own and transact RNG RINs; we are simply highlighting how parties that solely own and transact RNG RINs will operate in the context of the biogas regulatory reform provisions.

## X. Other Changes to Regulations

This section describes the other regulatory changes beyond those already discussed that we are finalizing for the fuel quality and RFS programs. We address comments related to these regulatory changes in RTC Section 11.

### *A. RFS Third-Party Oversight Enhancement*

Independent third-party auditors and engineers play critical roles in ensuring the integrity of the RFS program.[294] The independent third-party engineer ensures that a renewable fuel producer's facility can actually produce renewable fuel in accordance with the RFS regulations and thus generate valid RINs. The independent third-party auditor, when hired by a renewable fuel producer, verifies that the renewable fuel produced adheres to its registered and approved feedstocks and processes, and therefore verifies the RINs generated under the RFS QAP.[295] Given EPA's recent promulgation of a program allowing renewable fuel to be produced from biointermediates,[296] we expect there will be an expansion in the scope and number of regulated entities under the RFS program in the future, making third-party verifications even more critical.

We proposed changes to third-party verifications and submissions in the 2016 Renewables Enhancement Growth and Support (REGS) proposed rule;[297] however, those proposed changes were not finalized. We re-proposed (*i.e.,* proposed anew) some, but not all of those changes in conjunction with this rulemaking and are now finalizing a modified version of those proposed changes in this action.

As we explained in the 2016 REGS proposal, EPA has taken a number of enforcement actions against renewable fuel producers that generated invalid RINs, and the extent of the unlawful and fraudulent activities associated with the RFS program, as demonstrated by these cases, is troubling given the roles that independent third parties play in the RFS program. Because we are concerned that independent third-party auditors and engineers may not be sufficiently mitigating unlawful and fraudulent activities in the RFS program to the extent needed for a successful program, we are strengthening requirements that apply to these entities. Consequently, we are modifying the requirements for independent third-party auditors that use approved QAPs to audit renewable fuel production to verify that RINs are validly generated by the producer. The purpose of these modifications is to protect against conflicts of interest of QAP providers by strengthening the independence requirements for them. We are also making several changes to the requirements for the professional engineer serving as an independent third party conducting an engineering review for a renewable fuel producer as part of their RFS duties in connection to a renewable fuel producer's initial registration and subsequent registration updates.

The changes to the regulations that we are making fall into six areas. First, we are strengthening the independence requirements for third-party engineers by requiring those engineers to comply with similar requirements to those that apply to independent third-party auditors.

Second, we are requiring that the third-party engineer sign an electronic certification when submitting engineering reviews to EPA to ensure that the third-party engineer has personally reviewed the required facility documentation, including site visit requirements, and that the third-party engineer meets the applicable independence requirements. Previously, the third-party engineer signed a certification statement within the engineering review documents. We believe that an electronic certification at the time of submission will help to ensure that the third-party engineer conducts their duties with impartiality and independence.

Third, we are requiring that third-party engineers provide documents and

[294] We note that independent third parties serve a different function than the third parties discussed in Section IX.C. In this case, the independent third party must meet regulatorily specified requirements that ensure that the independent third party will objectively conduct verification activities under the RFS program. Third parties that informally assist compliance by regulated parties are not subject to those same independence requirements.

[295] Independent third-party engineers and auditors are referred to separately based on their roles in the RFS program. In order to participate in the RFS program, renewable fuel producers must have a third-party engineering review of their facility prior to generating RINs, and every three years thereafter. References to third-party professional engineers in this preamble refer to the third parties that conduct those engineering reviews. Third-party auditors verify that the renewable fuel produced by renewable fuel producers adheres to their registered and approved feedstocks and processes to generated QAPed RINs. These auditors may be professional engineers as well, but references to third-party auditors in this preamble refer to third parties (engineers and other types of professionals) that perform that QAP-related function.

[296] 87 FR 39600 (July 1, 2022).

[297] 81 FR 80828 (November 16, 2016).

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.

Fourth, we are requiring that three-year engineering review updates be conducted by a third-party engineer while the facility being reviewed is producing renewable fuel. We believe that the efficacy of a third-party engineer's review is greatly enhanced when the facility is operating under normal conditions and not in a shut down or maintenance posture. Conducting the engineering review while the facility is operational will allow the third-party engineer to accurately and completely verify the elements of the engineering review necessary to certify to EPA that the facility is in compliance with its registration materials.

Fifth, we are specifying that third-party auditors must ensure that personnel involved in third-party audits (including verification activities) are not negotiating for future employment with the owner or operator of the audited party. In the NPRM, we proposed to disallow a person employed by an independent third-party auditor who 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. Several commentors opposed this prohibition and 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. We agree that the proposed prohibition can be more narrowly tailored to address our primary concern, which is auditors negotiating for future employment while conducting auditing activities. We believe that third-party auditors could be unduly influenced in their QAP verification activities if they are negotiating for future employment while providing auditing services, and are finalizing a narrower prohibition that only applies to auditors that are negotiating for future employment with the audited party. This ensures the impartiality needed in third-party auditors without restricting individuals' ability to obtain future employment.

Sixth, we are specifying prohibited acts and liability provisions applicable to third-party engineers to reduce the potential of a conflict of interest with the renewable fuel producer. These requirements will help EPA and obligated parties better ensure that third-party audits and engineering reviews are being correctly conducted, provide greater accountability, and ensure that third-party auditors and engineers maintain a proper level of independence from the renewable fuel producer.

Taken together, we believe these six requirements will help avoid RIN fraud by strengthening third-party verification of renewable fuel producers' registration information. Additional information on third-party auditors and engineers is provided below.

1. Third-Party Auditors

Third-party independence is critical to the success of any third-party compliance program. We believe that the independence requirements applicable to third-party auditors in the RFS program should be clarified and strengthened to further minimize (and hopefully eliminate) any conflicts of interest between auditors and renewable fuel producers that might lead to improper RIN validation. We are clarifying the prohibition against an appearance of a conflict of interest to include:

• Acting impartially when performing all auditing activities.

• Prohibiting independent third-party auditors that were involved in the design or construction of a facility from auditing that facility.

• Prohibiting a person employed by an independent third-party auditor who is negotiating for future employment with the owner or operator of the audited party from participating in that audit.

These provisions are intended to prevent, among other things, third-party auditors that were involved in the design of a facility or who are negotiating for employment with the audited party from conducting QAP verification activities. In both instances, we believe that third-party auditors could be unduly influenced in their QAP verification activities as a result.

In the 2023–2025 NPRM, we proposed to prohibit third parties that offered QAP services from offering other business services to audited parties for a period of at least one year. One commentor stated that this prohibition was overreaching and would stifle the ability of large firms to provide QAP services because large firms often provide other services not associated with the design of the facility or the RFS program (*e.g.,* tax services), which would discourage large firms from providing QAP services. As discussed in RTC Section 11.1, we appreciate the commenter's concern and, therefore, are finalizing a narrower prohibition that only applies to third parties that were involved in the design or construction of the audited facility. This achieves the goal of the proposed provision without unnecessarily limiting the pool of third parties who can qualify as third-party auditors.

2. Third-Party Engineers

Engineering reviews from independent third-party engineers are integral to the successful implementation of the RFS program. Not only do they ensure that RINs are properly categorized, but they also provide a check against fraudulent RIN generation. As we have designed our registration system to accommodate the association between third-party auditors and renewable fuel producers to implement the RFS QAP, we have realized that both the way engineering reviews are conducted and the nature of the relationships among the third-party engineers, affiliates, and renewable fuel producers are analogous to third-party auditors and renewable fuel producers. As a result, we are strengthening the independence requirements for third-party engineers by requiring those engineers to comply with requirements similar to those that apply to independent third-party auditors.

We are also improving the RFS registration requirements for three-year engineering review updates by requiring site visits to take place when the facility is producing renewable fuel. This will provide the regulated community and EPA with greater confidence in the production capabilities of the renewable fuel facility. Since the adoption of the RFS2 requirements in 2010, most engineering reviews have been conducted by a handful of third-party engineers. Some of these engineers are using templates that make it difficult for EPA to determine whether registration information was verified.

We are concerned that, in some instances, the third-party engineers are relying too heavily on information provided by the renewable fuel producers, and not conducting a truly independent verification. In order to provide greater confidence in third-party engineering reviews, we are requiring that the engineering review submission include evidence of a site visit while the facility is producing the renewable fuel that it is registered to produce. We are also incorporating EPA's current interpretation and guidance into the regulations regarding actions that third-party engineers must take to verify information in the renewable fuel producer's registration application. The amendments explain that in order to verify the applicable registration information, the third-party auditor must independently evaluate and confirm the information and cannot rely on representations made by the renewable fuel producer. We are also requiring that the third-party engineer electronically certifies that the third-party meets the independence requirements whenever the third-party submits engineering reviews or engineering review updates to EPA. Previously, the third-party engineer signed a certification statement within the engineering review documents. Requiring the certification to be signed at the time of submission will remind the third-party engineer of the independence requirements prior to submitting the engineering reviews.

We believe these amendments will help provide greater assurance that third-party engineering reviews are based upon independent verification of the required registration information in 40 CFR 80.1450, helping to provide enhanced assurance of the integrity of the registration materials submitted by the facility, as well as the renewable fuel they produce.

Finally, we are specifying prohibited activities for third-party engineers failing to properly conduct an engineering review, or failing to disclose to EPA any financial, professional, business, or other interest with parties for whom the third-party engineer provides services for under the RFS registration requirements. Based on its review of RFS registrations, EPA has concerns that third-party engineers may not be appropriately conducting engineering reviews consistent with EPA's intent because they may not meet the requirements for independence to qualify as a third party. We believe that making third-party engineers more accountable for properly conducting engineering reviews under the regulations and requiring that they interact more directly with EPA will help us to identify potential conflicts of interest and to bring enforcement actions should an issue arise.

During discussions with stakeholders after publication of the NPRM, some parties suggested that EPA delay the implementation date for the enhancements to third-party oversight because third-party engineers will have already conducted three-year engineering site visits for facilities prior to the effective date of the rule that are due January 31, 2024, and it was unclear how these new changes would affect previously conducted site visits by independent third-party engineers that are due January 31, 2024. To address these concerns, we are specifying that the new requirements for independent third-party engineers and for engineering reviews will begin on February 1, 2024. A February 1, 2024, implementation date will ensure that three-year engineering reviews conducted to meet the January 31, 2024, deadline are not impacted by the new regulatory requirements avoiding duplicative effort on the part of independent third-party engineers.

*B. Deadline for Third-Party Engineering Reviews for Three-Year Updates*

We are finalizing with modification our proposal that third-party engineers conduct engineering review site visits no sooner than July 1 of the calendar year prior to the January 31 deadline for three-year registration updates. In response to public comments, we are also finalizing additional flexibility that will allow parties to reset their three-year update due date if they comply with the three-year update requirement before it was due. We believe this flexibility will allow parties to simultaneously comply with the RFS program and CARB's LCFS verification requirements. Finally, in response to public comments requesting more time to comply with the new requirements, we are finalizing that 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 those parties that may have already arranged for engineering review site visits under the previous regulatory requirements.

Previously, renewable fuel producers were required to have a third-party engineer conduct an updated engineering review three years after initial registration. The regulations stated that the three-year engineering review reports were due by January 31 three years after the first year of registration. However, the regulations did not specify when the third-party engineer must conduct the site visit. We received several inquiries from renewable fuel producers and third-party engineers concerning when the third-party engineer must conduct the site visit ahead of the January 31 deadline. We originally published guidance that stated that the site visits for three-year updates should occur no later than 120 days prior to the January 31 deadline. Due to extenuating circumstances, we have on a case-by-case basis allowed for site visits to occur up to a full calendar year prior to the deadline.

However, we continue to 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. To address our concern, we are requiring that the site visit occur no sooner than July 1 of the preceding calendar year. We believe that this amount of time will provide third-party engineers enough time (seven months) to conduct site visits and prepare and submit engineering review reports to EPA without the site visit becoming out-of-date. We believe this additional time is reasonable as the number of facilities that require three-year updates has increased.

We are also specifying which batches of RINs should be included in the $V_{RIN}$ calculation portion of the three-year registration update. Under this provision, third-party engineers must select from batches of renewable fuel produced through at least the second quarter of the calendar year prior to the applicable January 31 deadline for $V_{RIN}$ calculations. We believe this is necessary because some third-party engineers conduct $V_{RIN}$ calculations for facilities' RIN generation materials that only cover two years. Furthermore, we have noticed that the period from which batches are selected for $V_{RIN}$ calculations can vary significantly across third-party engineers and we want to ensure that this portion of the engineering review update is conducted consistently.

We received comments suggesting that we should accept engineering reviews with site visits that occurred within 12 months of the deadline, in part to align with California's verification requirements under their LCFS program. While we appreciate commenters' concerns that there may be overlapping verification requirements for the RFS program and California's LCFS, we note that most renewable fuel producers under the RFS program do not participate in California's program. However, in order to allow parties to utilize a single site visit for both programs, the final rule allows parties to reset their three-year updates, as long as they have complied with the regulatory requirements before the three-year update is due. This would have the added benefit of allowing a party that needed to undergo a new engineering review as required under 40 CFR 80.1450(d)(1) to use that new engineering review to fulfil their three-year engineering review update (assuming all applicable requirements for the three-year update are met).

Several commenters suggested that we postpone the implementation date for these provisions to avoid parties having to redo their three-year updates and engineering reviews because the regulatory requirements changed in the middle of a three-year update cycle. We agree with commenters' concerns and note that it was not our intent to require parties to comply with two sets of regulatory requirements for the same three-year update. Therefore, to address commenters' concerns and clarify our intent, we are requiring that the new deadline for three-year update site visits and VRIN requirements begins after the conclusion of the compliance year 2023 three-year update deadline (*i.e.,* February 1, 2024). We believe this implementation date will minimize the effects of these changes on parties that have already started complying with previous three-year update requirements and will allow for a smooth transition.

*C. RIN Apportionment in Anaerobic Digesters*

In the Pathways II rule, we created a pathway to allow D3 RINs to be generated for renewable CNG/LNG produced from biogas from digester types that process only predominately cellulosic [298] feedstocks (*i.e.,* municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters), as well as from the cellulosic components of biomass processed in other waste digesters.[299] We also created a renewable CNG/LNG pathway to allow for D5 RINs to be generated for biogas produced from other waste digesters.[300] If a party simultaneously converts a predominately cellulosic feedstock and a non-predominantly cellulosic feedstock in a waste digester, it must apportion the resulting RINs under the appropriate D3 and D5 pathways accordingly. To support this calculation, we required parties to calculate the cellulosic converted fraction (*i.e.,* the portion of a cellulosic feedstock that is converted into renewable fuel) based on measurements of cellulose obtained using a method that produces reasonably accurate results. For a heterogeneous feedstock such as separated food waste—which may be simultaneously converted with cellulosic feedstocks in waste digesters—the cellulosic content can vary widely between batches, making it very difficult for renewable fuel producers to determine the cellulosic content of the feedstock with any degree of accuracy.

Since the Pathways II rule was finalized, stakeholders have inquired how to apportion RINs in the specific case wherein feedstocks that are not predominantly cellulosic—specifically, separated food waste—are simultaneously converted with predominantly cellulosic feedstocks into biogas in a digester.[301] EPA's previous registration and RIN apportionment equations were designed assuming that the converted fractions of the cellulosic and non-cellulosic feedstocks could be accurately determined through chemical testing. However, apportioning RINs for biogas produced from co-processed feedstocks is distinct from apportioning RINs for other co-processed cellulosic and non-cellulosic feedstocks (*e.g.,* corn kernel fiber co-processed with corn starch). In the NPRM, we explained that some of the existing requirements are unnecessary or otherwise inappropriate for these circumstances and that there are features of co-processing in a digester that make it reasonable to consider a different regulatory approach to RIN apportionment. The feedstocks in question are generated as physically separate streams such that the mass, moisture content, and methane production potential of each feedstock can be determined before mixing, a possibility that was not contemplated by the previous apportionment equations. Further, we understand that parties interested in co-processing predominantly cellulosic feedstocks with separated food waste are not planning on claiming any credit for the cellulosic components of the food waste due to challenges accurately measuring cellulosic content of the variable food waste feedstock, which means that chemical analysis of the cellulosic content of the food waste feedstock and digestate is not required. Another factor that reduces the risk of D3 RINs being generated from non-cellulosic feedstock is that mixing of non-cellulosic food waste in anaerobic digestion does not lead to a decrease in biogas production relative to when the feedstocks are processed separately,[302] so the biogas production from the cellulosic feedstock processed alone provides an accurate or conservative estimate of the same feedstock's biogas production when mixed with non-cellulosic feedstocks.

In this action we are finalizing as proposed specific equations to determine feedstock energy for when predominantly cellulosic and non-predominantly cellulosic feedstocks are simultaneously converted in anaerobic digesters. We have made slight technical adjustments to these equations and changed their location relative to what was proposed to address commenter concerns. The cellulosic feedstock energy equation is similar to the existing, broader equations, with a few modifications. The new equation uses a volatile solids measurement since non-volatile solids do not generally produce biogas, increasing the accuracy over the existing equation. For calculating total solids and volatile solids, we are requiring the use of American Public Health Association method number 2540, which is already used by the wastewater treatment industry in their operations of anaerobic digesters. The non-predominantly cellulosic biogas is the difference between total biogas produced and cellulosic biogas as calculated by the cellulosic feedstock apportionment equation. We believe these equations will ensure that cellulosic RINs are only generated for predominately cellulosic feedstocks because they make a conservative assumption of the cellulosic biogas production and ensure that the biogas produced from non-predominantly cellulosic feedstocks generates entirely non-cellulosic RINs. Along with this updated equation, we are requiring biogas producers to keep records of feedstocks necessary to verify apportionment calculations.

To support this apportionment, we are finalizing that at registration biogas producers provide the converted fraction of the predominantly cellulosic feedstock used in an anerobic digester when it is simultaneously converted with a non-predominantly cellulosic feedstock as well as relevant supporting data. Instead of chemical data supporting a cellulosic converted fraction as required under the existing regulations, which will continue to apply for situations other than anaerobic digesters, we are requiring that, at registration, a facility producing biogas from anaerobic digestion either choose a predetermined, conservative value for converted fraction (explained in more detail below) or provide the following:

• Operational data showing the biogas yield from digesters which process solely the cellulosic feedstock(s) and which operate under similar conditions as the digesters addressed in the registration.

[298] A predominately cellulosic feedstock is a feedstock with an adjusted cellulosic content of greater than 75 percent.

[299] See row Q in Table 1 to 40 CFR 80.1426; 79 FR 42168 (July 18, 2014). D3 RINs may also be generated for renewable CNG/LNG produced from biogas from landfills—the landfill biogas pathway is not implicated by these changes.

[300] See row T in Table 1 to 40 CFR 80.1426; 79 FR 42168 (July 18, 2014). This pathway must be used if the feedstock being processed in a digester is not predominantly cellulosic.

[301] See Byron Bunker (EPA), ''Reply to American Biogas Council on the Treatment of Agricultural Digesters under the Renewable Fuel Standard (RFS) Program,'' March 15, 2017.

[302] Karki et al. Bioresource Technology 330 (2021) 125001. DOI: 10.1016/j.biortech.2021.125001.

• A description including any calculations demonstrating how the data were used to determine the cellulosic converted fraction.

• The cellulosic converted fraction that will be used in the RIN apportionment.

Operational data used to determine the cellulosic converted fraction will necessarily be obtained at a particular range of temperatures, pressures, residence times, feedstock composition, and other process variables. Since biogas production can change based on processing conditions, we are requiring a registrant to identify the conditions in its registration under which the facility will need to operate to properly apportion RINs. In specifying those processing conditions, we are requiring parties to place limitations on a combination of temperature, amount of each cellulosic feedstock source, solids retention time, hydraulic retention time, or other processing conditions established at registration which may impact the conversion of the predominantly cellulosic feedstock. These limitations must be based on the data used to derive the cellulosic converted fraction so that when it is simultaneously converting multiple feedstocks, the facility is operating under conditions essentially the same as those for the digesters from which the cellulosic converted fraction was derived. For example, a registrant that calculates a cellulosic converted fraction from historical data of a given digester processing a single type of cellulosic feedstock could use that historical operational data to identify the limitations on temperature, residence times, and other operational variables such that the converted fraction remains valid.

As an alternative to specifying operational data, we are allowing registrants to select a standard converted fraction value specified in the regulations for the specific cellulosic feedstock which they are simultaneously converting with a non-predominantly cellulosic feedstock in anaerobic digesters. We are providing specific standard values for four cellulosic feedstocks (bovine manure, chicken manure, swine manure, and WWTP sludge), which are 50 percent of the measured biochemical methane potential (BMP) obtained from published literature.[303] BMP typically results in a higher converted fraction than when the same feedstock is processed in industrial scale digesters. One study that looked at two digesters over the course of less than a year identified sustained periods where full scale digesters produced over 30 percent less methane than predicted by BMP and recommended that designers of digestion systems should assume 10–20 percent lower methane production in full scale digesters than from BMP.[304] Given the limited types of feedstocks, the limited number of digesters evaluated in this study, and the different goals behind the recommendations,[305] we chose a more conservative estimate of 50 percent lower methane production and added specific processing requirements to ensure that D3 RINs generated meet the statutory goal.[306] In the NPRM, we requested comments for other default values of converted fractions. We received multiple comments suggesting that EPA use a conservative default value for cellulosic converted fraction that is 80% of the biomethane potential instead of 50% of the biomethane potential which we proposed. However, as discussed in more detail in the RTC document, the commenters did not provide necessary detail or representative data to justify a higher value, nor did they explain why the higher value was necessary given the ability to submit operational data at registration to establish a higher value. Given these factors, we are finalizing as proposed that the conservative estimates are 50 percent of the biomethane potential. Additionally, one commenter identified a discrepancy between higher heating and lower heating values, and we have corrected the default cellulosic converted fraction to use higher heating values, consistent with the equations in which the value is used.

As with other biogas, biogas produced from simultaneously converting predominantly cellulosic and non-predominantly cellulosic feedstocks is also eligible to be used as renewable CNG/LNG; a biointermediate; or other renewable fuel. We are requiring that the different D-codes be tracked through PTDs from biogas producers and RNG producers, as well as reporting of D-code information into EMTS. Under this approach, biogas producers will specify the proportion of biogas by D-code on their PTDs. The parties using the biogas to generate RINs for RNG (as discussed in Section IX) will use this proportion to calculate the appropriate number of D3 and D5 RINs.

*D. BBD Conversion Factor for Percentage Standard*

In the 2020–2022 proposed rule, we proposed a change to the conversion factor used in the calculation of applicable percentage standards for BBD.[307] We did not finalize that proposed change in the 2020–2022 final rule. We are now finalizing that change to be implemented for compliance years 2023 and beyond, and we are including data from 2022 in the determination of the appropriate revised conversion factor.

In the 2010 RFS2 rule, we determined that because the BBD standard was a ''diesel'' standard, its volume must be met on a biodiesel-equivalent energy basis.[308] In contrast, the other three standards (cellulosic biofuel, advanced biofuel, and total renewable fuel) must be met on an ethanol-equivalent energy basis. At that time, biodiesel was the only advanced renewable fuel that could be blended into diesel fuel, qualified as an advanced biofuel, and was available at greater than de minimis quantities.

When we established the formula for calculating the applicable percentage standards for BBD in 2010, the formula needed to accommodate the fact that the volume requirement for BBD would be based on biodiesel equivalence while the other three volume requirements would be based on ethanol equivalence. Given the nested nature of the standards, however, RINs representing BBD would also need to be valid for complying with the advanced biofuel and total renewable fuel standards. To this end, we designed the formula for calculating the percentage standard for BBD to include a factor that would convert biodiesel volumes into their ethanol equivalent. This factor was the same as the Equivalence Value (EqV) for biodiesel, 1.5, as discussed in the 2007

[303] Dairy manure value comes from Labatut et al. (2011) Bioresource Technology, 102, p. 2255–2264. DOI: 10.1016/j.biortech.2010.10.035. Swine manure data comes from Vedrenne et al. (2008) Bioresource Technology, 99, p. 146–155. DOI: 10.1016/j.biortech.2006.11.043. Chicken manure data comes from Li et al. (2013) Applied Biochemistry Biotechnology 171, p. 117–127. DOI: 10.1007/s12010–013–0335–7. Municipal sludge data comes from Holliger et al. (2017) Frontiers in Energy Research, 5, 12. DOI: 10.3389/fenrg.2017.00012. Values were converted using the ideal gas law at the stated or inferred conditions and 21,496 Btu lower heating value methane per lb methane.

[304] Holliger et al. (2017) Frontiers in Energy Research, 5, 12. DOI: 10.3389/fenrg.2017.00012.

[305] When designing a gas treatment system, one may use a slight overestimate of biogas production to maximize RNG production. Overestimating is less of a problem in designing a gas treatment system than it is in the RFS program, since overestimating production of biogas will lead to invalidly generated RINs.

[306] See memo ''Final calculation of cellulosic converted fraction values from biochemical methane potential,'' available in the docket for this action.

[307] 86 FR 72474 (December 21, 2021).

[308] See 75 FR 14670, 14682 (March 26, 2010).

RFS1 final rule.[309] The resulting formula [310] (incorporating the recent modification to the definitions of $GE_i$ and $DE_i$) [311] is shown below:

$$Std_{BBD,i} = 100 \times \frac{RFV_{BBD,i} \times 1.5}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

Where:

$Std_{BBD,i}$ = The biomass-based diesel standard for year i, in percent.

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallons.

$G_i$ = Amount of gasoline projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons.

$D_i$ = Amount of diesel projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons.

$RG_i$ = Amount of renewable fuel blended into gasoline that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons.

$RD_i$ = Amount of renewable fuel blended into diesel that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons.

$GS_i$ = Amount of gasoline projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

RGSi = Amount of renewable fuel blended into gasoline that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

$DS_i$ = Amount of diesel projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

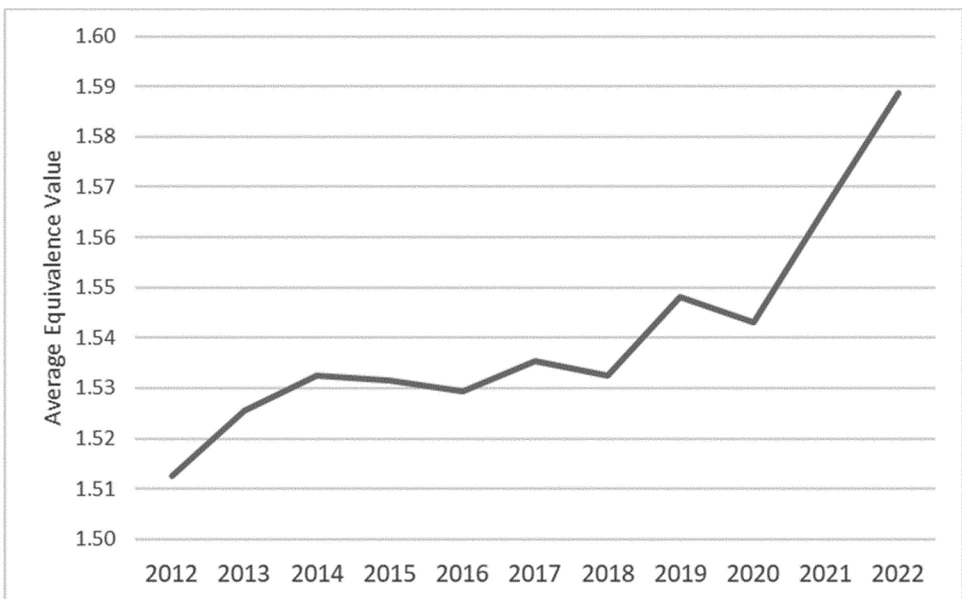
$RDS_i$ = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

$GE_i$ = The total amount of gasoline projected to be exempt in year i, in gallons, per §§ 80.1441 and 80.1442.

$DE_i$ = The total amount of diesel projected to be exempt in year i, in gallons, per §§ 80.1441 and 80.1442.

In the years following 2010 when the percentage standard formula for BBD was first promulgated, advanced renewable diesel production has grown. Most renewable diesel has an EqV of 1.7, and its growing presence in the BBD pool means that the average EqV of BBD has also grown.[312]

**Figure X.D-1: Average EqV for BBD Containing Both Biodiesel and Renewable Diesel**




**Source**: Consumption of Biodiesel and Renewable Diesel with D4 RINs according to Data from EMTS

Because the formula currently specified in the regulations for calculation of the BBD percentage standard assumes that all BBD used to satisfy the BBD standard is biodiesel, it biases the resulting percentage standard low, given that in reality there is some renewable diesel in BBD. The bias is small, on the order of two percent, and has not impacted the supply of BBD since it is the higher advanced biofuel standard—rather than the BBD standard—that has driven the demand for BBD. Nevertheless, we believe that it is appropriate to modify the factor used in the formula to more accurately reflect the amount of renewable diesel in the BBD pool.

The average EqV of BBD appears to have grown over time without stabilizing. This trend has continued and is consistent with the growth in facilities producing renewable diesel.[313] We proposed to replace the factor of 1.5 in the percentage standard formula for BBD with a factor of 1.57 based on the average EqV for BBD in 2021, while also

[309] See 72 FR 23900, 23921 at Table III.B.4–1 (May 1, 2007).

[310] See 40 CFR 80.1405(c).

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

[312] Under 40 CFR 80.1415(b)(4), renewable diesel with a lower heating value of at least 123,500 Btu/gallon is assigned an EqV of 1.7. A minority of renewable diesel has a lower heating value below 123,500 BTU/gallon and is therefore assigned an EqV of 1.5 or 1.6 based on applications submitted under 40 CFR 80.1415(c)(2).

[313] See RIA Chapter 5.2.

noting that ‘‘we believe that the factor used in the formula for calculating the percentage standard for BBD should be at least 1.57.’’ [314] Commenters were generally supportive of this change, with some suggesting the factor should be higher than proposed, and others suggesting we should be open to revisiting this factor again in the future as renewable diesel production increases. Based on the updated data for 2022 shown in Figure X.D–1 showing an average EqV for BBD of 1.59 in 2022, we now believe that the factor used in the formula for calculating the percentage standard for BBD should be at least 1.59. However, we also believe that maintaining consistency with the rounding protocol adopted for EqVs in 2007 is important. As described in the RFS1 rule, all EqVs are rounded to the first decimal place.[315] Applying that rounding protocol here results in factor of 1.6. This is slightly higher than the proposed value of 1.57, but is more consistent with the additional data for 2022 and application of the aforementioned rounding protocol. We are therefore replacing the factor of 1.5 in the percentage standard formula for BBD with a factor of 1.6.[316] Note that we are not changing any other aspect of the percentage standard formula for BBD.

*E. Flexibility for RIN Generation*

We are revising 40 CFR 80.1426 to simplify and clarify the requirement that renewable fuel producers and importers may only generate RINs if they meet all applicable requirements under the RFS program for the generation of RINs. The regulations EPA promulgated in the 2010 RFS2 final rule at 40 CFR 80.1426(a)(1), (a)(2), and (b) state, in part, that renewable fuel producers ‘‘must’’ generate RINs if they meet certain requirements, and 40 CFR 80.1426(c), in turn, prohibits the generation of RINs if a renewable fuel producer cannot demonstrate that they meet the requirements in 40 CFR 80.1426(a)(1), (a)(2), and (b). That rule retained the word ‘‘must’’ from the RFS1 regulations but also made it clear that parties cannot generate RINs for biofuel if the feedstock used to produce that biofuel does not satisfy the renewable biomass requirements or if the renewable fuel producer has not met all other applicable requirements, including registration, reporting, and recordkeeping requirements.[317] EPA’s longstanding interpretation of these regulatory requirements is that renewable fuel producers that do not want to generate RINs can choose to not register, keep records, or report to EPA. In light of this approach, we have determined that a more straightforward approach will be to revise the regulations to allow, rather than require, RINs to be generated for qualifying renewable fuel. Thus, we are revising 40 CFR 80.1426(a)(1), (a)(2) and (b) to state that RINs ‘‘may only’’ be generated if certain requirements are met. We are also removing the provisions for small volume renewable fuel producers at 40 CFR 80.1426(c)(2), (c)(3), and 40 CFR 80.1455 because those provisions are no longer necessary. If any renewable fuel producer, regardless of size, has the ability to choose to generate RINs, then there is no longer a need to provide flexibility for small producers because they will only choose to generate RINs if it were economically beneficial to do so.

*F. Changes to Tables in 40 CFR 80.1426*

We are making changes to Tables 1 through 4 to 40 CFR 80.1426 in order to conform with current guidelines from the Office of Federal Register (OFR).[318] These tables were designated to 40 CFR 80.1426 and we refer to them as ‘‘Table 1 to 40 CFR 80.1426,’’ ‘‘Table 2 to 40 CFR 80.1426,’’ etc. Under OFR’s guidelines, this way of referring to the tables meant that they should be located at the very end of 40 CFR 80.1426. However, Tables 1 and 2 were located after 40 CFR 80.1426(f)(1)(vi), Table 3 was located in 40 CFR 80.1426(f)(3)(v), and Table 4 was located in 40 CFR 80.1426(f)(3)(vi)(A).

In order to conform with OFR’s guidelines, we are moving Tables 1 and 2 to the end of 40 CFR 80.1426, consistent with their current designation. Since we are not changing the designations or contents of these tables as part of this move, all of the existing references to these tables throughout 40 CFR part 80, subpart M, as well as all references in existing EPA actions and documents (including **Federal Register** notices, guidance documents, and adjudications) will remain accurate and valid. In contrast, for Tables 3 and 4, we are creating new provisions within the regulations into which we are moving and consolidating the formulas in these tables. Specifically, we are moving and consolidating the five formulas previously in Table 3 into 40 CFR 80.1426(f)(3)(v), and moving and consolidating the five formulas previously in Table 4 into 40 CFR 80.1426(f)(3)(vi)(A). The formulas themselves remain unchanged and since there are no other references to these tables outside of the paragraphs in which they were located, no additional revisions are necessary to implement this change.

*G. Prohibition on RIN Generation for Fuels Not Used in the Covered Location*

We are revising 40 CFR 80.1426(c) and 40 CFR 80.1431 to reiterate that parties (*e.g.,* foreign RIN-generating renewable fuel producers and importers) cannot generate RINs for renewable fuel unless it was produced for use in the covered location. The CAA and RFS regulations already limit RIN generation to renewable fuel produced for use in the United States, and these amendments are intended to address any potential confusion on the part of stakeholders. The amendments specify that RINs cannot be generated for renewable fuel that is not produced for use in in the covered location and make such RINs invalid. We note that it is a prohibited activity under 40 CFR 80.1460(b)(2) to generate or transfer invalid RINs, and this revision reinforces that generating RINs for fuel not produced for use in the covered location is a prohibited activity.

*H. Separated Food Waste Recordkeeping Requirements*

Under the CAA, qualifying renewable fuel must be produced from renewable biomass.[319] To ensure that RIN-generating renewable fuels satisfy this requirement, RFS regulations contain, among other things, recordkeeping provisions that 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 if RINs are generated.’’ [320] In addition to the generally applicable requirements, the RFS regulations also contain provisions for specific types of feedstocks where necessary to ensure that their use is consistent with the statutory and regulatory definitions of renewable biomass.

[314] 87 FR 80582, 80686 (December 30, 2022).

[315] 72 FR 23921, May 1, 2007.

[316] While we are revising the factor of 1.5 in the percentage standard formula for BBD, we have included all four of the percentage standard formulas in our amendatory text for 40 CFR 80.1405(c). This is due to the manner in which the original formulas were published in the CFR, which does not allow for revisions to a single formula without republishing all of the formulas. We are not modifying any aspect of these formulas beyond the change to the factor of 1.5 in the BBD formula.

[317] 40 CFR 80.1426(a)(1)(iii).

[318] Office of the Federal Register, National Archives and Records Administration, ‘‘Document Drafting Handbook,’’ August 2018 Edition (Revision 1.4), January 7, 2022.

[319] CAA section 211(o)(1)(J).

[320] 40 CFR 80.1454(d).

One such set of feedstock-specific requirements exists for separated food waste used to produce renewable fuel. In 2010, EPA promulgated a requirement that renewable fuel producers using separated food waste submit, at the time of their registration with EPA to generate RINs: (1) The location of any facility from which the waste stream consisting solely of separated food waste is collected; and (2) A separated food waste plan.[321] However, an unintended effect of requiring renewable fuel producers to submit the locations of the facilities from which separated food waste was collected as part of their facility registration was that producers were required to update their information with EPA every time their feedstock suppliers changed. EPA recognized this could be burdensome for producers and, in 2016, proposed to revise the regulations to remove this provision as a registration requirement and to simply rely on the corresponding recordkeeping requirement.[322] At that time, we noted that renewable fuel producers were also required to retain this information under the recordkeeping requirements under 40 CFR 80.1454.[323]

In 2020, we finalized the removal of this registration requirement and also reiterated that, pursuant to the existing recordkeeping provisions at 40 CFR 80.1454(d), renewable fuel producers were still required to ''keep documents associated with feedstock purchases and transfers that identify where the feedstocks were produced; these documents must be sufficient to verify that the feedstocks meet the definition of renewable biomass.'' [324] To emphasize that this requirement remained in the regulations in light of removing the corresponding registration requirement, we also promulgated a provision at 40 CFR 80.1454(j)(1)(ii) requiring renewable fuel producers to keep documents demonstrating the location of any establishment from which the separated food waste stream is collected.

The Clean Fuels Alliance America challenged EPA's promulgation of the separated food waste recordkeeping provision at 40 CFR 80.1454(j)(1)(ii). Petitioners alleged the requirement that renewable fuel producers keep records demonstrating the location of any establishment from which separated food waste is collected is arbitrary and capricious and that renewable fuel producers ''had no opportunity to comment because EPA failed to mention this new recordkeeping requirement in the proposed rule.'' [325]

In the proposal for this action, we emphasized that 40 CFR 80.1454(d), which was introduced in 2010, requires 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. However, recognizing that affected stakeholders may have had suggestions for how to better apply this requirement specifically to separated food waste feedstocks, we sought comment on the separated food waste-specific recordkeeping requirement in 40 CFR 80.1454(j)(1)(ii).[326] In particular, we sought comment on how renewable fuel producers using separated food waste as feedstocks could best implement, in a manner consistent with standard business practices within the industry, the requirement to keep records demonstrating where their feedstocks were produced and that the records would be sufficient to verify that the feedstocks meet the definition of renewable biomass. Based on previous discussions with third party feedstock suppliers, independent auditors, and renewable fuel producers we did not propose to modify the provisions of 40 CFR 80.1454. After review and consideration of the comments received on this action, we are not finalizing any of the modifications to the language from those comments. However, we are finalizing the alternative approach that we did propose with modifications based on the comments we received as described below.

We understand there is a desire for independent auditors to play a role in satisfying the requirement that renewable fuel producers keep records demonstrating the location of any establishment from which separate food waste is collected. Specifically, stakeholders have requested that, rather than renewable fuel producers holding the records themselves, independent auditors be allowed to verify the records directly from the feedstock aggregator. While the regulations require the renewable fuel producer to keep the records on the feedstock source and amount as specified under 40 CFR 80.1454(j), as further explained below, we are providing an option to allow independent auditors to verify records held by the feedstock aggregator by leveraging the biointermediates provisions of the RFS program. While most interest in this provision centers around used cooking oil collection, we believe this option can also be useful to third-party collectors of separated yard waste, separated food waste, and separated municipal solid waste.

Under the new option, instead of the renewable fuel producers holding records demonstrating that the feedstock used to produce renewable fuel is renewable biomass, feedstock aggregators may hold them provided that alternative regulatory requirements for the renewable fuel producer and feedstock aggregator are met. The alternative requirements needed to be met are summarized as follows:

- The feedstock aggregator will need to register with EPA and must keep all applicable records of feedstock collection.
- The renewable fuel producer will need to participate in the QAP program.
- PTDs will need to be supplied to the transferee for feedstocks after leaving the feedstock aggregator that include the volume, date, location at time of transfer, and transferor and transferee information.

The feedstock aggregator and the renewable fuel producer that processes those feedstocks will also be subject to the same liability provisions that apply to biointermediate producers and renewable fuel producers that process biointermediates. We note that under the RFS program, other than the limited alternative that we are finalizing in this action, renewable fuel producers must keep records to demonstrate that their renewable fuels are produced from renewable biomass as specified under 40 CFR 80.1454, as applicable. We are finalizing the alternative approach to address the specific circumstance where it is impractical for renewable fuel producers to provide the records specified under the recordkeeping requirements. We also note that if the records do not demonstrate the feedstock is renewable biomass, then the recordkeeping requirement is not met regardless of who is holding the records.

We received comments that having both the renewable fuel producer and feedstock aggregator be subject to QAP would be overly burdensome. We did not intend to have the feedstock aggregator directly participate in the QAP program like a biointermediate

[321] 40 CFR 80.1450(b)(1)(vii)(B).

[322] 81 FR 80828, 80902–03 (November 16, 2016).

[323] *Id.* (''The recordkeeping section of the regulations requires 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 the feedstocks meet the definition of renewable biomass.'').

[324] 85 FR 7016, 7062 (February 6, 2020).

[325] *RFS Power Coalition* v. *U.S. EPA,* No. 20–1046 (D.C. Cir.), Doc. # 1882940 at 38–39, filed Jan. 29, 2021.

[326] We are not reopening the requirement at 40 CFR 80.1454(d).

producer as proposed in the NRPM, and we recognize that imposing direct participation of the feedstock aggregator could significantly increase the burden associated with the proposed option on feedstock aggregators. Based on these comments, we are requiring that only the renewable fuel producer needs to participate in the QAP program (instead of the proposed requirement to have the aggregator also participate). To ensure adequate oversight, we are also requiring that the QAP plan include a description of how the third-party auditor will audit each feedstock aggregator.

We also received comments asking for clarity regarding which obligations apply to feedstock suppliers versus feedstock aggregators. We intended the regulations to cover feedstock aggregators, not feedstock suppliers. We have clarified this in the regulations by updating the language and adding new definitions for feedstock aggregator and feedstock supplier.

Some commenters inquired about third parties holding records on behalf of the feedstock renewable fuel producer.[327] Under EPA's fuels programs, which includes the RFS program, we do not specify how parties must employ persons to fulfill their regulatory burdens so long as the specified party meets all applicable regulatory requirements. We believe that a party may arrange for a contractor to perform actions that meet regulatory requirements (*e.g.,* taking samples, analyzing samples, and reporting results to EPA) so long as that contractor adheres to the regulatory requirements, is acting on behalf of the regulated party, and the party understands that they will remain liable for ensuring the applicable regulatory requirements have been met. We believe this same arrangement is allowed for the separated food waste recordkeeping requirements. We want to reiterate, however, that the regulated party is liable for meeting the CAA and regulatory requirements and for any action of any party working on their behalf, whether it is a contractor, subcontractor, or other entity. The renewable fuel producer must make or arrange for the records to be made available to EPA upon request consistent with the regulatory requirements at 40 CFR 80.1454(t). Since the parties that are completing work on behalf of the regulated party are not independent of the company, they do not meet the independence requirements for QAP auditors or attest auditors, so they cannot audit the company in these roles. With the important conditions described here, we believe EPA's acceptance of contractors to conduct work on behalf of regulated parties addresses the commenters request to describe more clearly the circumstances when a contractor may hold the required feedstock records on behalf of a renewable fuel producer.

Since the feedstock aggregators are not substantially altering the feedstock before transferring the feedstock, we believe fewer requirements are necessary than for biointermediates to provide sufficient oversight of the feedstock and renewable fuel production process. Specifically, we are not requiring that the feedstock aggregator supply an engineering review, separated food waste plan, separated yard waste plan, or separated MSW plan as a part of registration. However, the renewable fuel producer will still need to supply these documents as part of their registration. In addition, the feedstock is not considered a biointermediate, so the feedstock aggregator can sell feedstock to a biointermediate producer, which could then sell a biointermediate to a renewable fuel facility.

### *I. Definition of Ocean-Going Vessels*

We are revising the definition of ''fuel used in ocean-going vessels'' as proposed with slight modification to ensure that obligated parties include diesel fuel in their RVOs in a consistent manner and as required by the CAA and so that renewable fuel producers know which fuels used in marine applications are eligible for RIN generation.

Fuel used in ocean-going vessels is explicitly excluded from the CAA's definition of ''transportation fuel,'' [328] and does not need to be included in RVO calculations.[329] Relatedly, renewable fuel producers cannot generate RINs on renewable fuel used in ocean-going vessel because such fuel is not considered transportation fuel.[330] The RFS regulations defined the term ''[f]uel for use in an ocean-going vessel'' to mean: ''(1) any marine residual fuel (whether burned in ocean waters, Great Lakes, or other internal waters); (2) Emission Control Area (ECA) marine fuel, pursuant to § 80.2 and 40 CFR 1090.80 (whether burned in ocean waters, Great Lakes, or other internal waters); and (3) Any other fuel intended for use only in ocean-going vessels.'' [331] The term ''ocean-going vessels'' referenced in sub-prong (3), however, was not further defined in the regulations.

In the RFS2 final rule, we stated that EISA specifies that ''transportation fuels'' do not include fuels for use in ocean-going vessels and that we were interpreting that ''fuels for use in ocean-going vessels'' means residual or distillate fuels other than motor vehicle, nonroad, locomotive, or marine diesel fuel (MVNRLM) intended to be used to power large ocean-going vessels (*e.g.,* those vessels that are powered by Category 3 (C3), and some Category 2 (C2), marine engines and that operate internationally).[332] This statement made clear that vessels powered by C3 marine engines are ocean-going vessels and that fuel supplied to those vessels does not need to be included in obligated parties' RVO calculations.

We further explained the reference to ''and some Category (C2) marine engines'' in the RFS2 RTC document, in which we noted that while Category 1 (C1) and C2 engines are generally required to use MVNLRM diesel fuel (*i.e.,* transportation fuel), we had, at the time, recently established new standards for C3 marine engines that allowed C1 and C2 auxiliary engines equipped on vessels powered by C3 marine engines to utilize fuels other than MVNRLM diesel fuel.[333] We noted further that this could result in a vessel carrying three fuels: MVNRLM, ECA marine fuel, and residual fuels, and the latter two would not be considered transportation fuel under the program. In other words, the reference to ''and some Category (C2) marine engines'' in the RFS2 final rule refers to auxiliary engines equipped on vessels that are primarily powered by C3 marine engines.

Since the RFS2 regulations were promulgated, we have received several questions from the regulated community on the subject of what constitutes an ocean-going vessel, and what fuel must be included in obligated parties' RVO calculations. To address this, we proposed to define ocean-going vessels as ''vessels that are primarily (*i.e.,* ≥75 percent) propelled by engines meeting the definition of 'Category 3' in 40 CFR 1042.901.'' In other words, if a vessel is primarily propelled by C3 marine engines, it is an ocean-going vessel. Further, fuel used in Category 1 (C1) and Category 2 (C2) auxiliary engines installed on ocean-going vessels—which

[327] Commenters recommended this in part because they would like to use third-party tracking software to manage the collection and disclosure of data.

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

[329] 40 CFR 80.1407(f)(8).

[330] 40 CFR 80.1426(a)(1)(iv).

[331] 40 CFR 80.1401.

[332] 75 FR 14670, 14721 (March 26, 2010).

[333] U.S. EPA, Renewable Fuel Standards Program (RFS2) Summary and Analysis of Comments, at 3–198–3–200. (February 2010).

are often used for purposes other than propulsion—do not need to be included in obligated parties' RVO calculations because the inquiry turns on the type of engine that primarily propels the vessel, not the actual engines that use the fuel. On the other hand, if a vessel is primarily propelled by C1 or C2 marine engines, they are not ocean-going vessels regardless of whether those vessels operate on international waters, and fuel supplied to these vessels must be included in obligated parties' RVO calculations.

We received one comment on the proposed definition of ''ocean-going vessel.'' The commentor stated that is unclear from the proposed definition how an obligated party supplying marine fuel would have knowledge about the percentage of propulsion provided by a vessel's various Category 1, 2, or 3 engines. 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 primary type of engine used to propel a vessel. 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 that 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.''

We are also revising the definitions of MVNRLM diesel fuel and ECA marine fuel to be consistent with the flexibilities that allow for the exclusion of certified NTDF from refiners' RVOs [334] and the flexibilities to certify diesel fuel for multiple purposes as allowed under EPA's fuel quality regulations.[335] Specifically, we are removing the restriction that fuel that meets the requirements of MVNRLM diesel fuel cannot be ECA marine fuel, as this exclusion conflicts with the designation provisions in 40 CFR part 1090.[336]

The previous definitions for MVNRLM diesel fuel and ECA marine fuel excluded fuel that conforms to the requirements of MVNRLM diesel fuel from the definition of ECA marine fuel, without regard to its actual use. Under this language, obligated parties who produced 15 ppm diesel fuel had to include the designated MVNRLM diesel fuel in their RVO calculations even if the fuel was designated and used as ECA marine fuel. In the 2020 annual rule, we intended that obligated parties could use the certified NTDF provisions to exclude ECA marine fuel used in ocean-going vessels but did not revise the definitions of MVNRLM diesel fuel and ECA marine fuel consistent with our intent. In this action, we are amending the definitions of MVNRLM diesel fuel and ECA marine fuel to clarify that 15 ppm distillate fuel that is properly designated as certified NTDF may also be designated as ECA marine fuel and excluded from a producer or importer's RVO calculations.

### *J. Bond Requirement for Foreign RIN-Generating Renewable Fuel Producers and Foreign RIN Owners*

We are finalizing two changes to the bonding requirements for foreign RIN-generating renewable fuel producers and foreign RIN owners. First, we are increasing the amount of the foreign bond amount from $0.01 to $0.22 per RIN. The bond requirement previously applicable to foreign RIN-generating renewable fuel producers and foreign RIN owners was developed in the RFS1 rule to deter noncompliance and to assist with the collection of any judgments that result from a foreign RIN-generating renewable fuel producer's noncompliance with the RFS regulations.[337] In that rulemaking, the bond was set to $0.01 per RIN, when the expected value of RINs was much lower. Since 2013, RIN prices have hovered significantly above $0.01, and recently, RINs in all categories have consistently sold above $1.00 per RIN.[338] As explained in the 2023–2025 NPRM, the increased value of RINs makes a bond requirement of $0.01 per RIN neither sufficient to deter potential noncompliance nor likely to yield bonds of sufficient size to satisfy judicial or administrative judgments against foreign RIN-generating renewable fuel producers or foreign RIN owners. For these reasons, we are raising the bond requirement to more accurately reflect the current value of RINs, so that bonds can serve their intended purposes. While we had proposed raising the bond requirement to $0.30 per RIN—which was 10 percent of the price of a D3 RIN at the time of the proposal—after considering the comments received, we have re-calculated the amount to $0.22 per RIN, which is 10 percent of the average price of a D3 RIN for the most recent, full five-year period (2018–2022).[339] This approach accounts for recent fluctuations in price over a longer and representative time period.

Second, we are removing the option to make a direct payment to the U.S. Treasury under 40 CFR 80.1466(h) and are adopting the surety bond as the sole method to fulfill the foreign bond requirement. We have considered a variety of options used by other EPA programs and by other Federal agencies, including examining the financial assurance methods used by EPA for the Resource Conservation and Recovery Act (RCRA) and for the Transition Program for Equipment Manufacturers (TPEM) program. We also considered approaches used by other federal agencies, such as the Alcohol and Tobacco Trade Board (TTB) brewer's bonds, including surety and collateral (''cash'') bonds. Our inquiry led us to conclude that alternative approaches either do not work with the RFS program or are too burdensome to implement, and that the surety bond approach is the most appropriate and workable for the RFS program.

The effective date for the new bonding provisions will be April 1, 2024. We are giving a later effective date because we appreciate that parties may need this additional time to come into compliance with these new bonding requirements.

[334] 40 CFR 80.1407(f)(11).

[335] 40 CFR 1090.1015(a).

[336] We note that we are not changing the treatment of certified NTDF under the RFS program in this action.

[337] 72 FR 24007 (May 1, 2007).

[338] See RFS pricing data available at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.*

[339] We selected average D3 RIN prices over the previous five years to smooth out fluctuations in RIN prices over time. We did not base our bond amount on projected RIN prices because estimating future RIN prices involves a lot of uncertainty and would not necessarily provide a more appropriate bond price. We pegged our bond prices to D3 RINs because D3 RINs have historically been the most valuable, and the purpose of the change is to ensure that bond prices serve as a sufficient deterrent to non-compliance by foreign parties. Pegging the price to a less valuable RIN would erode the efficacy of the deterrent. We chose 10 percent because we believed a higher percentage may be too costly for foreign RIN generators/owners to participate in the program. Percentages lower than 10 percent would have resulted in an insufficient deterrent against non-compliance.

*K. Definition of Produced From Renewable Biomass*

We are not finalizing at this time a definition of produced from renewable biomass or the related amendments to the regulatory provisions related to co-processed fuels. CAA section 211(o)(1)(J) defines 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.'' [340] However, neither the CAA nor EPA regulations define what it means for a fuel to be produced from renewable biomass. In the 2020–2022 NPRM, we proposed to define in 40 CFR 80.1401 that ''produced from renewable biomass'' means the energy in the finished fuel comes from renewable biomass. After reviewing comments on that proposal, we decided not to finalize a definition for ''produced from renewable biomass'' in that action. In the 2023–2025 NPRM, we re-proposed the definition of ''produced from renewable biomass'' again based on the energy content approach that was in the 2020–2022 NPRM. We also sought comment on alternative definitions and ways that renewable fuel producers could demonstrate that the fuel they produce meets this statutory requirement. These included both a ''mass-based'' definition where the mass in the finished fuel comes from the renewable biomass, as well as a ''broad'' approach whereby either the energy or the mass could come from the renewable biomass.

We received near universal support from stakeholders in comment on the proposal for the broad approach. In order to allow us more time to fully consider the comments received, as well as to determine what would be needed to implement such a broad approach, we are not finalizing a definition of ''produced from renewable biomass'' in this action. Nevertheless, we still believe a definition of ''produced from renewable biomass'' would be useful because we have received multiple questions from stakeholders on this aspect of the renewable fuel definition. Clarifying what it means for a fuel to be produced from renewable biomass will reduce confusion on this issue and avoid a situation where a party expends resources on researching or developing a new fuel technology with the hopes of generating RINs only to later discover that the fuel does not qualify as having been produced from renewable biomass.

Given that we are not finalizing this definition in this action, we are also not finalizing the proposed changes to corresponding regulations in 80.1426(f)(4) nor are we finalizing the proposed changes to the definition of co-processed fuel or co-processed intermediate.

*L. Technical Amendments*

We are making numerous technical amendments to the RFS and fuel quality regulations. These amendments are being made to correct minor inaccuracies and clarify the current regulations. These changes are described in Table X.L–1.

TABLE X.L–1—MISCELLANEOUS TECHNICAL CORRECTIONS AND CLARIFICATIONS TO RFS AND FUEL QUALITY REGULATIONS

| Part and section of Title 40 | Description of revision |
|---|---|
| 80.2 | Adding definition of business days consistent with the definition at 40 CFR 1090.80. |
| 80.2 | Clarifying the definition of renewable fuel to specify that fuel must be used in the covered location. |
| 80.4; 80.7; 80,11; 80.1415; 80.1416; 80.1426; 80.1431; 80.1441; 80.1443; 80.1449 through 80.1454; 80.1456; 80.1466; 80.1467; 80.1469; 80.1474; and 80.1478. | Removing all references to "the Administrator" and replacing them with "EPA." |
| 80.2, 80.1408, and 1090.1015 | Amending the definition of certified non-transportation distillate fuel (NTDF) at 40 CFR 80.2 and the diesel fuel designation requirements under 40 CFR 1090.1015 to clarify that the certified NTDF provisions at 40 CFR 80.1408 may be used for NTDF other than heating oil or ECA marine fuel. |
| 80.2 and 80.1453(a)(12) | Clarifying that renewable naphtha may be blended to make E85. |
| 80.1450(b)(1)(viii)(E) | Clarifying that independent third-party engineers must visit material recovery facilities as part of the engineering review for facilities that produce renewable fuels from separated MSW. |
| 80.1469(c)(6) | Clarifying that independent third-party auditors must review all relevant documentation required under the RFS program when verifying elements under the QAP program. |
| 1090.55(c) | Amending to correct cross-reference from 40 CFR part 32 to 2 CFR part 1532. |
| 1090.80 | Amending to correct the list of states that are part of PADD II. |
| 1090.805(a)(1)(iv) | Clarifying that RCOs may add a delegate, as allowed under 1090.800(d). |
| 1090.1830(a)(3) | Amending to add a missing word. |

## XI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders*.

*A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review*

Under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094, this action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to suggestions or recommendations received as part of the Executive Order 12866 review process have been documented in the docket. EPA prepared an analysis of potential costs and benefits associated with this action. This analysis is presented in the RIA, available in the docket for this action.

*B. Paperwork Reduction Act (PRA)*

The information collection activities in this rule have been submitted for

[340] CAA section 211(o)(2)(A)(i) adds the requirement that renewable fuel must have ''lifecycle [GHG] emissions that are at least 20 percent less than baseline lifecycle [GHG] emissions'' (unless exempted under the statutory grandfather provision as implemented in 40 CFR 80.1403).

approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that EPA prepared has been assigned EPA ICR number 2722.02. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

We are finalizing compliance provisions necessary to ensure that the production, distribution, and use of biogas, RNG, and RINs are consistent with Clean Air Act requirements under the RFS program. These compliance provisions include registration, reporting, product transfer documents (PTDs), and recordkeeping requirements. The information requirements are under 40 CFR part 80, subparts E and M, and 40 CFR part 1090. Interested parties may wish to review the following related ICRs: Fuels Regulatory Streamlining (Final Rule), OMB Control Number 2060–0731, expires January 31, 2024; Renewable Fuel Standard (RFS) Program: RFS Final Rules, OMB Control No. 2060–0740, expires October 31, 2025; and Renewable Fuel Standard (RFS) Program (Renewal), OMB Control Number 2060–0725, expires November 30, 2025.

*Respondents/affected entities:* Biogas producers; RNG producers; RNG importers; biogas closed-distribution RIN generators; QAP providers; RIN separators; parties including renewable fuel producers, biointermediate producers, or feedstock aggregators who use alternative recordkeeping under 80.1479; producers of renewable fuel from biogas used as a biointermediate or RNG used as a feedstock; and third parties, including third-party engineers and attest auditors.

*Respondent's obligation to respond:* Mandatory, under 40 CFR parts 80 and 1090.

*Estimated number of respondents:* 7,835.

*Frequency of response:* On occasion, monthly, quarterly, or annually.

*Total estimated burden:* 82,441 hours (per year). Burden is defined at 5 CFR 1320.3(b).

*Total estimated cost:* $5,684,472 (per year), of which $5,659,472 is purchased services, and which includes $25,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, EPA will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

### *C. Regulatory Flexibility Act (RFA)*

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA.

For the biogas regulatory reform provisions, we are modifying the previous biogas provisions to make compliance less burdensome for regulated parties. With respect to the other amendments to the RFS and fuel quality regulations, this action makes minor corrections and modifications to those regulations. As such, we do not anticipate that there will be any significant adverse economic impact on directly regulated small entities as a result of these revisions.

The small entities directly regulated by the annual percentage standards associated with the RFS volumes are small refiners that produce gasoline or diesel fuel, which are defined by the Small Business Administration (SBA) at 13 CFR 121.201. To evaluate the impacts of the 2023–2025 volume requirements on small entities, we have conducted a screening analysis [341] to assess whether we should make a finding that this action will not have a significant economic impact on a substantial number of small entities. Currently available information shows that the impact on small entities from implementation of this rule will not be significant. We have reviewed and assessed the available information, which shows that obligated parties, including small entities, are able to recover the cost of acquiring the RINs necessary for compliance with the RFS standards through higher sales prices of the petroleum products they sell than would be expected in the absence of the RFS program.[342] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs. The costs of the RFS program are thus being passed on to consumers in a highly competitive marketplace.

While the rule will not have a significant economic impact on a substantial number of small entities, there are existing compliance flexibilities in the program that are available to small entities. These flexibilities include being able to comply through RIN trading rather than renewable fuel blending, 20 percent RIN rollover allowance (up to 20 percent of an obligated party's RVO can be met using previous-year RINs), and deficit carry-forward (the ability to carry over a deficit from a given year into the following year, provided that the deficit is satisfied together with the next year's RVO). In the 2010 RFS2 final rule, we discussed other potential small entity flexibilities that had been suggested by the Small Business Regulatory Enforcement Fairness Act (SBREFA) panel or through comments, but we did not adopt them, in part because we had serious concerns regarding our authority to do so.[343]

In sum, this rule will not change the compliance flexibilities currently offered to small entities under the RFS program and available information shows that the impact on small entities from implementation of this rule will not be significant.

### *D. Unfunded Mandates Reform Act (UMRA)*

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, for state, local, or tribal governments. This action imposes no enforceable duty on any state, local or tribal governments. This action contains a federal mandate under UMRA that may result in expenditures of $100 million or more for the private sector in any one year. Accordingly, the costs associated with this rule are discussed in Section IV and in the RIA.

This action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

### *E. Executive Order 13132: Federalism*

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

### *F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

This action does not have tribal implications as specified in Executive Order 13175. This action will be implemented at the Federal level and affects transportation fuel refiners,

[341] See RIA Chapter 11.

[342] For a further discussion of the ability of obligated parties—including small refiners—to recover the cost of RINs, see April 2022 SRE Denial Action and June 2022 SRE Denial Action.

[343] 75 FR 14858–62 (March 26, 2010).

blenders, marketers, distributors, importers, exporters, and renewable fuel producers and importers. Tribal governments will be affected only to the extent they produce, purchase, or use regulated fuels. Thus, Executive Order 13175 does not apply to this action.

*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866, and EPA believes that the environmental health or safety risks of the pollutants impacted by this action may have a disproportionate effect on children. The 2021 Policy on Children's Health also applies to this action.[344]

Children make up a substantial fraction of the U.S. population, and often have unique factors that contribute to their increased risk of experiencing a health effect from exposures to ambient air pollutants because of their continuous growth and development. Children are more susceptible than adults to many air pollutants because they have: (1) A developing respiratory system; (2) Increased ventilation rates relative to body mass compared with adults; (3) An increased proportion of oral breathing, particularly in boys, relative to adults; and (4) Behaviors that increase chances for exposure. Even before birth, the developing fetus may be exposed to air pollutants through the mother that affect development and permanently harm the individual when the mother is exposed. Certain motor vehicle emissions present greater risks to children as well. Early life stages (*e.g.,* children) are thought to be more susceptible to tumor development than adults when exposed to carcinogenic chemicals that act through a mutagenic mode of action.[345] Exposure at a young age to these carcinogens could lead to a higher risk of developing cancer later in life.

[344] U.S. Environmental Protection Agency (2021). 2021 Policy on Children's Health. Washington, DC. *https://www.epa.gov/system/files/documents/2021-10/2021-policy-on-childrens-health.pdf.*

[345] U.S. Environmental Protection Agency. (2005). Supplemental guidance for assessing susceptibility from early-life exposure to carcinogens. Washington, DC: Risk Assessment Forum. EPA/630/R–03/003F. *https://www.epa.gov/sites/default/files/2013-09/documents/childrens_supplement_final.pdf.*

The biofuel volumes associated with this rulemaking may reduce GHGs, potentially mitigating the impacts of climate change on children. Because children have greater susceptibility to the impacts of a changing climate, as referenced in RIA Chapter 9.6, these standards could have particular benefits for children's health.[346] As discussed in RIA Chapter 4, the biofuel volumes associated with the rulemaking may also impact other air pollutant emissions both positively and negatively. Because of their greater susceptibility to air pollution and their increased time spent outdoors these standards could also have more pronounced impacts on children's health.

*H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use*

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This action establishes the required renewable fuel content of the transportation fuel supply for 2023, 2024, and 2025 pursuant to the CAA. The RFS program and this rule are designed to achieve positive effects on the nation's transportation fuel supply by increasing energy independence and security.

*I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51*

This action involves technical standards. In accordance with the requirements of 1 CFR 51.5, we are incorporating by reference the use of test methods and standards from the American Petroleum Institute (API), American Public Health Association (APHA), ASTM International (ASTM), and European Committee for Standardization (CEN). A detailed discussion of these test methods and standards can be found in Sections IX.I and X.C. The standards and test methods referenced in this action may be obtained through the following avenues:

For API standards, copies of these materials may be obtained from the API website (*www.api.org*) or by calling API at (202) 682–8000. API standards referenced in this rule are also available for public review in read-only format in the API IBR Reading Room at *publications.api.org*.

[346] The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment, USGCRP 2016.

For APHA standards, copies of these materials may be obtained from the standard methods website (*www.standardmethods.org*) or by calling APHA at (202) 777–2742.

For ASTM standards, copies of these materials may be obtained from the ASTM website (*www.astm.org*) or by calling ASTM at (877) 909–2786. ASTM standards referenced in this rule are also available for public review in read-only format in the ASTM Reading Room at *www.astm.org/epa.htm*.

For CEN standards, copies of these materials may be obtained from the CEN website (*www.cencenelec.eu*) or by calling CEN at + 32 2 550 08 11.

To meet the Office of the Federal Register requirements for incorporation by reference structure and formatting requirements, EPA is moving the centralized IBR section (§ 80.1468, which applies to all of part 80) out of subpart M and into subpart A (which also applies to all of part 80). EPA is also adding standards that were approved for § 80.8 but never consolidated in the original centralized IBR section into the new centralized section at § 80.12.

In addition to the standards and test methods listed below, ASTM D1250, ASTM D4442, ASTM D4444, ASTM D6866, and ASTM E870 are also referenced in the regulatory text of this final rule. They were approved for IBR for the sections referenced as of July 1, 2022, and no changes are being made aside from those described to the centralized IBR section. ASTM D4057, ASTM D4177, ASTM D5842, and ASTM D5854 are also referenced in the regulatory text of this final rule. They were approved for IBR for the sections referenced as of April 28, 2014, and no changes are being made aside from those described to the centralized IBR section. ASTM E711 is also referenced in the regulatory text of this final rule. It was approved for IBR for the section referenced as of July 1, 2010, and no changes are being made aside from those described to the centralized IBR section.

TABLE XI.I–1—STANDARDS AND TEST METHODS TO BE INCORPORATED BY REFERENCE

| Organization and standard or test method | Description |
|---|---|
| API MPMS 14.1–2016, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016. | Standard describing how to collect, handle, and transfer gas samples for chemical analysis. |
| API MPMS 14.3.1–2012, Manual of Petroleum Measurement Standards Chapter 14.3.1—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022. | Standard describing engineering equations, installation requirements, and uncertainty estimations of square-edged orifice meters in measuring the flow of natural gas and similar fluids. |
| API MPMS 14.3.2–2016, Manual of Petroleum Measurement Standards Chapter 14.3.2—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016. | Standard describing design and installation of square-edged orifice meters for measuring flow of natural gas and similar fluids. |
| API MPMS 14.3.3–2013, Manual of Petroleum Measurement Standards Chapter 14.3.3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021. | Standard describing applications using square-edged orifice meters for measuring flow of natural gas and similar fluids. |
| API MPMS 14.3.4–2019, Manual of Petroleum Measurement Standards Chapter 14.3.4—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019. | Standard describing the development of equations for coefficient of discharge, including a calculation procedure, for square-edged orifice meters measuring flow of natural gas and similar fluids. |
| API MPMS 14.12–2017, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluid Measurement Section 12—Measurement of Gas by Vortex Meters, 1st Edition, March 2017. | Standard describing the calculation of flow using gas vortex meters for measuring the flow of natural gas and similar fluids. |
| APHA SM 2540, Solids, revised June 10, 2020 | Standard describing how to measure the total solids, volatile solids, and other solid properties of wastewater sludge and similar substances. |
| ASTM D975–21, Standard Specification for Diesel Fuel, approved August 1, 2021. | Diesel fuel specifications that must be met to qualify for RINs for renewable fuels. |
| ASTM D3588–98(R2017)e1, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, approved April 1, 2017. | Calculation protocol for aggregate properties of gaseous fuels from compositional measurements. |
| ASTM D4888–20, Standard Test Method for Water Vapor in Natural Gas Using Length-of-Stain Detector Tubes, approved December 15, 2020. | Standard specifying how to measure water vapor concentration in gaseous fuel samples |
| ASTM D5504–20, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, approved November 1, 2020. | Standard specifying how to measure sulfur-containing compounds in a gaseous fuel sample. |
| ASTM D6751–20a, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved August 1, 2020. | Biodiesel fuel specifications that must be met to qualify for RINs for renewable fuels. |
| ASTM D6866–22, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved March 15, 2022. | Radiocarbon dating test method to determine the renewable content of biogas and RNG. |
| ASTM D7164–21, Standard Practice for On-line/At-line Heating Value Determination of Gaseous Fuels by Gas Chromatography, approved April 1, 2021. | Standard specifying how to use and maintain an on-line gas chromatogram for determining heating value of a gaseous fuel. |
| ASTM D8230–19, Standard Test Method for Measurement of Volatile Silicon-Containing Compounds in a Gaseous Fuel Sample Using Gas Chromatography with Spectroscopic Detection, approved June 1, 2019. | Standard specifying how to measure silicon-containing compounds in a gaseous fuel sample. |
| EN 17526:2021(E), Gas meter—Thermal-mass flow-meter based gas meter, approved July 11, 2021. | Standard specifying the measurement of flow using a thermal mass flow meter. |

### *J. Executive Orders 12898 (Federal Actions To Address Environmental Justice in Minority Populations, and Low-Income Populations) and 14096 (Revitalizing Our Nation's Commitment to Environmental Justice for All)*

Executive Order 12898 (59 FR 7629, February 16, 1994) directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on communities with environmental justice concerns.

EPA believes that the human health and environmental conditions that exist prior to this action result in disproportionate and adverse effects on communities with environmental justice concerns. A summary of our approach for considering potential EJ concerns as a result of this action can be found in Sections I.B and IV.E, and our EJ analysis (including a discussion of this action's potential impacts on GHGs, air quality, water quality, and fuel and food prices) can be found in RIA Chapter 9.

EPA believes that this action may result in some new disproportionate and adverse effects on communities with environmental justice concerns, while also mitigating some effects on these populations. Some of these effects are not practicable to assess. This rule will reduce GHG emissions, which will benefit communities with environmental justice concerns. The manner in which the market responds to the provisions in this rule could also have non-GHG impacts. Replacing petroleum fuels with renewable fuels can also have localized impacts on water and air exposure for communities living near facilities that produce renewable fuel, gasoline, or diesel fuel. Replacing petroleum fuels with renewable fuels is projected to have marginal impacts on food and fuel prices. These price impacts may have disproportionate impacts on low-income populations who spend a larger proportion of their income on food and fuel. EPA received public comment from several groups concerned about the use of biogas in the RFS, particularly from landfills and concentrated animal feeding operations. EPA solicited further discussion from these groups when considering the environmental justice impacts of this rule. The majority of the comments and feedback received was focused on potential impacts of the proposed renewable electricity provisions, which we have decided not to finalize with this action. However, EPA will continue to engage with stakeholders on impacts of the RFS program related to biogas use and expansion.

*K. Congressional Review Act (CRA)*

This action is subject to the CRA, and EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is a ''major rule'' as defined by 5 U.S.C. 804(2).

## XII. Statutory Authority

Statutory authority for this action comes from sections 114, 203–05, 208, 211, and 301 of the Clean Air Act, 42 U.S.C. 7414, 7522–24, 7542, 7545, and 7601.

## List of Subjects

*40 CFR Part 80*

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Oil imports, Petroleum, Renewable fuel.

*40 CFR Part 1090*

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Oil imports, Petroleum, Renewable fuel.

**Michael S. Regan,**
*Administrator.*

For the reasons set forth in the preamble, EPA amends 40 CFR parts 80 and 1090 as follows:

## PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

■ 1. The authority citation for part 80 continues to read as follows:

**Authority:** 42 U.S.C. 7414, 7521, 7542, 7545, and 7601(a).

## Subpart A—General Provisions

■ 2. Revise § 80.2 to read as follows:

### § 80.2 Definitions.

The definitions of this section apply in this part unless otherwise specified. Note that many terms defined here are common terms that have specific meanings under this part.

*Actual peak capacity* means 105% of the maximum annual volume of renewable fuels produced from a specific renewable fuel production facility on a calendar year basis.

(1) For facilities that commenced construction prior to December 19, 2007, the actual peak capacity is based on the last five calendar years prior to 2008, unless no such production exists, in which case actual peak capacity is based on any calendar year after startup during the first three years of operation.

(2) For facilities that commenced construction after December 19, 2007 and before January 1, 2010, that are fired with natural gas, biomass, or a combination thereof, the actual peak capacity is based on any calendar year after startup during the first three years of operation.

(3) For all other facilities not included above, the actual peak capacity is based on the last five calendar years prior to the year in which the owner or operator registers the facility under the provisions of § 80.1450, unless no such production exists, in which case actual peak capacity is based on any calendar year after startup during the first three years of operation.

*Adjusted cellulosic content* means the percent of organic material that is cellulose, hemicellulose, and lignin.

*Advanced biofuel* means renewable fuel, other than ethanol derived from cornstarch, that has lifecycle greenhouse gas emissions that are at least 50 percent less than baseline lifecycle greenhouse gas emissions.

*Agricultural digester* means an anaerobic digester that processes only animal manure, crop residues, or separated yard waste with an adjusted cellulosic content of at least 75%. Each and every material processed in an agricultural digester must have an adjusted cellulosic content of at least 75%.

*Algae grown photosynthetically* are algae that are grown such that their energy and carbon are predominantly derived from photosynthesis.

*Annual cover crop* means an annual crop, planted as a rotation between primary planted crops, or between trees and vines in orchards and vineyards, typically to protect soil from erosion and to improve the soil between periods of regular crops. An annual cover crop has no existing market to which it can be sold except for its use as feedstock for the production of renewable fuel.

*Approved pathway* means a pathway listed in table 1 to § 80.1426 or in a petition approved under § 80.1416 that is eligible to generate RINs of a particular D code.

*Areas at risk of wildfire* are those areas in the ''wildland-urban interface'', where humans and their development meet or intermix with wildland fuel. Note that, for guidance, the SILVIS laboratory at the University of Wisconsin maintains a website that provides a detailed map of areas meeting this criteria at: *www.silvis.forest.wisc.edu/projects/US_WUI_2000.asp.* The SILVIS laboratory is located at 1630 Linden Drive, Madison, Wisconsin 53706 and can be contacted at (608) 263–4349.

*A–RIN* means a RIN verified during the interim period by a registered independent third-party auditor using a QAP that has been approved under § 80.1469(a) following the audit process specified in § 80.1472.

*Assigned RIN* means a RIN assigned to a volume of renewable fuel or RNG pursuant to § 80.1426(e) or § 80.125(c), respectively, with a K code of 1.

*Audited facility* means any facility audited under an approved quality assurance plan under this part.

*Audited party* means a party that pays for or receives services from an independent third party under this part.

*Baseline lifecycle greenhouse gas emissions* means the average lifecycle greenhouse gas emissions for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005.

*Baseline volume* means the permitted capacity or, if permitted capacity cannot be determined, the actual peak capacity or nameplate capacity as applicable pursuant to § 80.1450(b)(1)(v)(A) through (C), of a specific renewable fuel production facility on a calendar year basis.

*Batch pathway* means each combination of approved pathway, equivalence value as determined under § 80.1415, and verification status for which a facility is registered.

*Biocrude* means a liquid biointermediate that meets all the following requirements:

(1) It is produced at a biointermediate production facility using one or more of the following processes:

(i) A process identified in row M under table 1 to § 80.1426.

(ii) A process identified in a pathway listed in a petition approved under § 80.1416 for the production of renewable fuel produced from biocrude.

(2) It is to be used to produce renewable fuel at a refinery as defined in 40 CFR 1090.80.

*Biodiesel* means a mono-alkyl ester that meets ASTM D6751 (incorporated by reference, see § 80.12).

*Biodiesel distillation bottoms* means the heavier product from distillation at a biodiesel production facility that does not meet the definition of biodiesel.

*Biogas* means a mixture of biomethane, inert gases, and impurities that meets all the following requirements:

(1) It is produced through the anaerobic digestion of renewable biomass under an approved pathway.

(2) Non-renewable components have not been added.

(3) It requires removal of additional components to be suitable for its designated use (*e.g.,* as a biointermediate, to produce RNG, or to produce biogas-derived renewable fuel).

*Biogas closed distribution system* means the infrastructure contained between when biogas is produced and when biogas or treated biogas is used to produce biogas-derived renewable fuel within a discrete location or series of locations that does not include placement of biogas, treated biogas, or RNG on a natural gas commercial pipeline system.

*Biogas closed distribution system RIN generator* means any party that generates RINs for renewable CNG/LNG in a biogas closed distribution system.

*Biogas-derived renewable fuel* means renewable CNG/LNG or any other renewable fuel that is produced from biogas or RNG, including from biogas used as a biointermediate.

*Biogas producer* means any person who owns, leases, operates, controls, or supervises a biogas production facility.

*Biogas production facility* means any facility where biogas is produced from renewable biomass under an approved pathway.

*Biogas used as a biointermediate* means biogas or treated biogas that a renewable fuel producer uses to produce renewable fuel other than renewable CNG/LNG at a separate facility from where the biogas is produced.

*Biointermediate* means any feedstock material that is intended for use to produce renewable fuel and meets all the following requirements:

(1) It is produced from renewable biomass.

(2) It has not previously had RINs generated for it.

(3) It is produced at a facility registered with EPA that is different than the facility at which it is used as feedstock material to produce renewable fuel.

(4) It is produced from the feedstock material identified in an approved pathway, will be used to produce the renewable fuel listed in that approved pathway, and is produced and processed in accordance with the process(es) listed in that approved pathway.

(5) Is one of the following types of biointermediate:

(i) Biocrude.

(ii) Biodiesel distillate bottoms.

(iii) Biomass-based sugars.

(iv) Digestate.

(v) Free fatty acid (FFA) feedstock.

(vi) Glycerin.

(vii) Soapstock.

(viii) Undenatured ethanol.

(ix) Biogas used to make a renewable fuel other than renewable CNG/LNG.

(6) It is not a feedstock material identified in an approved pathway that is used to produce the renewable fuel specified in that approved pathway.

*Biointermediate import facility* means any facility as defined in 40 CFR 1090.80 where a biointermediate is imported from outside the covered location into the covered location.

*Biointermediate importer* means any person who owns, leases, operates, controls, or supervises a biointermediate import facility.

*Biointermediate producer* means any person who owns, leases, operates, controls, or supervises a biointermediate production facility.

*Biointermediate production facility* means all of the activities and equipment associated with the production of a biointermediate starting from the point of delivery of feedstock material to the point of final storage of the end biointermediate product, which are located on one property, and are under the control of the same person (or persons under common control).

*Biomass-based diesel* means a renewable fuel that has lifecycle greenhouse gas emissions that are at least 50 percent less than baseline lifecycle greenhouse gas emissions and meets all of the requirements of paragraph (1) of this definition:

(1)(i) Is a transportation fuel, transportation fuel additive, heating oil, or jet fuel.

(ii) Meets the definition of either biodiesel or non-ester renewable diesel.

(iii) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79, if the fuel or fuel additive is intended for use in a motor vehicle.

(2) Renewable fuel produced from renewable biomass that is co-processed with petroleum is not biomass-based diesel.

*Biomass-based sugars* means sugars (*e.g.,* dextrose, sucrose, etc.) extracted from renewable biomass under an approved pathway, other than through a form change specified in § 80.1460(k)(2).

*Biomethane* means methane produced from renewable biomass.

*B–RIN* means a RIN verified during the interim period by a registered independent third-party auditor using a QAP that has been approved under § 80.1469(b) following the audit process specified in § 80.1472.

*Business day* has the meaning given in 40 CFR 1090.80.

*Canola/Rapeseed oil* means either of the following:

(1) *Canola oil* is oil from the plants *Brassica napus, Brassica rapa, Brassica juncea, Sinapis alba,* or *Sinapis arvensis,* and which typically contains less than 2 percent erucic acid in the component fatty acids obtained.

(2) *Rapeseed oil* is the oil obtained from the plants *Brassica napus, Brassica rapa,* or *Brassica juncea.*

*Carrier* means any distributor who transports or stores or causes the transportation or storage of gasoline or diesel fuel without taking title to or otherwise having any ownership of the gasoline or diesel fuel, and without altering either the quality or quantity of the gasoline or diesel fuel.

*Category 3 (C3) marine vessels,* for the purposes of this part 80, are vessels that are propelled by engines meeting the definition of ''Category 3'' in 40 CFR 1042.901.

*CBOB* means gasoline blendstock that could become conventional gasoline solely upon the addition of oxygenate.

*Cellulosic biofuel* means renewable fuel derived from any cellulose, hemicellulose, or lignin that has lifecycle greenhouse gas emissions that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.

*Cellulosic biogas feedstock* means an individual feedstock used to produce biogas that contains at least 75%

average adjusted cellulosic content and whose batch pathway has been assigned a D code of 3 or 7.

*Cellulosic diesel* is any renewable fuel which meets both the definitions of cellulosic biofuel and biomass-based diesel. Cellulosic diesel includes heating oil and jet fuel produced from cellulosic feedstocks.

*Certified non-transportation 15 ppm distillate fuel* or *certified NTDF* means distillate fuel that meets all the following:

(1) The fuel has been certified under 40 CFR 1090.1000 as meeting the ULSD standards in 40 CFR 1090.305.

(2) The fuel has been designated under 40 CFR 1090.1015 as certified NTDF.

(3) The fuel has also been designated under 40 CFR 1090.1015 as 15 ppm heating oil, 15 ppm ECA marine fuel, or other non-transportation fuel (*e.g.,* jet fuel, kerosene, or distillate global marine fuel).

(4) The fuel has not been designated under 40 CFR 1090.1015 as ULSD or 15 ppm MVNRLM diesel fuel.

(5) The PTD for the fuel meets the requirements in § 80.1453(e).

*Combined heat and power (CHP),* also known as cogeneration, refers to industrial processes in which waste heat from the production of electricity is used for process energy in a biointermediate or renewable fuel production facility.

*Continuous measurement* means the automated measurement of specified parameters of biogas, treated biogas, or natural gas as follows:

(1) For in-line GC meters, automated measurement must occur and be recorded no less frequent than once every 15 minutes.

(2) For flow meters, automated measurement must occur no less frequent than once every 6 seconds, and weighted totals of such measurement must be recorded at no more than 1 minute intervals.

(3) For all other meters, automated measurement and recording must occur at a frequency specified at registration.

*Contractual affiliate* means one of the following:

(1) Two parties are contractual affiliates if they have an explicit or implicit agreement in place for one to purchase or hold RINs on behalf of the other or to deliver RINs to the other. This other party may or may not be registered under the RFS program.

(2) Two parties are contractual affiliates if one RIN-owning party purchases or holds RINs on behalf of the other. This other party may or may not be registered under the RFS program.

*Control area* means a geographic area in which only oxygenated gasoline under the oxygenated gasoline program may be sold or dispensed, with boundaries determined by Clean Air Act section 211(m) (42 U.S.C. 7545(m)).

*Control period* means the period during which oxygenated gasoline must be sold or dispensed in any control area, pursuant to Clean Air Act section 211(m)(2) (42 U.S.C. 7545(m)(2)).

*Conventional gasoline (CG)* means any gasoline that has been certified under 40 CFR 1090.1000(b) and is not RFG.

*Co-processed* means that renewable biomass or a biointermediate was simultaneously processed with fossil fuels or other non-renewable feedstock in the same unit or units to produce a fuel that is partially derived from renewable biomass or a biointermediate.

*Co-processed cellulosic diesel* is any renewable fuel that meets the definition of cellulosic biofuel and meets all the requirements of paragraph (1) of this definition:

(1)(i) Is a transportation fuel, transportation fuel additive, heating oil, or jet fuel.

(ii) Meets the definition of either biodiesel or non-ester renewable diesel.

(iii) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79, if the fuel or fuel additive is intended for use in a motor vehicle.

(2) Co-processed cellulosic diesel includes all the following:

(i) Heating oil and jet fuel produced from cellulosic feedstocks.

(ii) Cellulosic biofuel produced from cellulosic feedstocks co-processed with petroleum.

*Corn oil extraction* means the recovery of corn oil from the thin stillage and/or the distillers grains and solubles produced by a dry mill corn ethanol plant, most often by mechanical separation.

*Corn oil fractionation* means a process whereby seeds are divided in various components and oils are removed prior to fermentation for the production of ethanol.

*Corporate affiliate* means one of the following:

(1) Two RIN-holding parties are corporate affiliates if one owns or controls ownership of more than 20 percent of the other.

(2) Two RIN-holding parties are corporate affiliates if one parent company owns or controls ownership of more than 20 percent of both.

*Corporate affiliate group* means a group of parties in which each party is a corporate affiliate to at least one other party in the group.

*Covered location* means the contiguous 48 states, Hawaii, and any state or territory that has received an approval from EPA to opt-in to the RFS program under § 80.1443.

*Crop residue* means biomass left over from the harvesting or processing of planted crops from existing agricultural land and any biomass removed from existing agricultural land that facilitates crop management (including biomass removed from such lands in relation to invasive species control or fire management), whether or not the biomass includes any portion of a crop or crop plant. Biomass is considered crop residue only if the use of that biomass for the production of renewable fuel has no significant impact on demand for the feedstock crop, products produced from that feedstock crop, and all substitutes for the crop and its products, nor any other impact that would result in a significant increase in direct or indirect GHG emissions.

*Cropland* is land used for production of crops for harvest and includes cultivated cropland, such as for row crops or close-grown crops, and non-cultivated cropland, such as for horticultural or aquatic crops.

*Diesel fuel* means any of the following:

(1) Any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is one of the following:

(i) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel.

(ii) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (*e.g.,* biodiesel fuel).

(iii) A mixture of fuels meeting the criteria of paragraphs (1)(i) and (ii) of this definition.

(2) For purposes of subpart M of this part, any and all of the products specified at § 80.1407(e).

*Digestate* means the material that remains following the anaerobic digestion of renewable biomass in an anaerobic digester. Digestate must only contain the leftovers that were unable to be completely converted to biogas in an anaerobic digestor that is part of an EPA-accepted registration under § 80.1450.

*Distillate fuel* means diesel fuel and other petroleum fuels that can be used in engines that are designed for diesel fuel. For example, jet fuel, heating oil, kerosene, No. 4 fuel, DMX, DMA, DMB, and DMC are distillate fuels; and natural gas, LPG, gasoline, and residual fuel are not distillate fuels. Blends containing residual fuel may be distillate fuels.

*Distillers corn oil* means corn oil recovered at any point downstream of when a dry mill ethanol or butanol plant grinds the corn, provided that the corn starch is converted to ethanol or butanol, the recovered oil is unfit for human food use without further refining, and the distillers grains remaining after the dry mill and oil recovery processes are marketable as animal feed.

*Distillers sorghum oil* means grain sorghum oil recovered at any point downstream of when a dry mill ethanol or butanol plant grinds the grain sorghum, provided that the grain sorghum is converted to ethanol or butanol, the recovered oil is unfit for human food use without further refining, and the distillers grains remaining after the dry mill and oil recovery processes are marketable as animal feed.

*Distributor* means any person who transports or stores or causes the transportation or storage of gasoline or diesel fuel at any point between any gasoline or diesel fuel refinery or importer's facility and any retail outlet or wholesale purchaser-consumer's facility.

*DX RIN* means a RIN with a D code of X, where X is the D code of the renewable fuel as identified under § 80.1425(g), generated under § 80.1426, and submitted under § 80.1452. For example, a D6 RIN is a RIN with a D code of 6.

*ECA marine fuel* is diesel, distillate, or residual fuel that meets the criteria of paragraph (1) of this definition, but not the criteria of paragraph (2) of this definition.

(1) All diesel, distillate, or residual fuel used, intended for use, or made available for use in Category 3 marine vessels while the vessels are operating within an Emission Control Area (ECA), or an ECA associated area, is ECA marine fuel, unless it meets the criteria of paragraph (2) of this definition.

(2) ECA marine fuel does not include any of the following fuel:

(i) Fuel used by exempted or excluded vessels (such as exempted steamships), or fuel used by vessels allowed by the U.S. government pursuant to MARPOL Annex VI Regulation 3 or Regulation 4 to exceed the fuel sulfur limits while operating in an ECA or an ECA associated area (see 33 U.S.C. 1903).

(ii) Fuel that conforms fully to the requirements of this part for MVNRLM diesel fuel (including being designated as MVNRLM).

(iii) Fuel used, or made available for use, in any diesel engines not installed on a Category 3 marine vessel.

*Ecologically sensitive forestland* means forestland that meets either of the following criteria:

(1) An ecological community with a global or state ranking of critically imperiled, imperiled or rare pursuant to a State Natural Heritage Program. For examples of such ecological communities, see ''Listing of Forest Ecological Communities Pursuant to 40 CFR 80.1401; S1–S3 communities,'' which is number EPA–HQ–OAR–2005–0161–1034.1 in the public docket, and ''Listing of Forest Ecological Communities Pursuant to 40 CFR 80.1401; G1–G2 communities,'' which is number EPA–HQ–OAR–2005–0161–2906.1 in the public docket. This material is available for inspection at the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The telephone number for the Air Docket is (202) 566–1742.

(2) Old growth or late successional, characterized by trees at least 200 years in age.

*End of day* means 7 a.m. Coordinated Universal Time (UTC).

*Energy cane* means a complex hybrid in the Saccharum genus that has been bred to maximize cellulosic rather than sugar content. For the purposes of this part:

(1) Energy cane excludes the species *Saccharum spontaneum,* but may include hybrids derived from *S. spontaneum* that have been developed and publicly released by USDA; and

(2) Energy cane only includes cultivars that have, on average, at least 75% adjusted cellulosic content on a dry mass basis.

*EPA Moderated Transaction System (EMTS)* means a closed, EPA moderated system that provides a mechanism for screening and tracking RINs under § 80.1452.

*Existing agricultural land* is cropland, pastureland, and land enrolled in the Conservation Reserve Program (administered by the U.S. Department of Agriculture's Farm Service Agency) that was cleared or cultivated prior to December 19, 2007, and that, on December 19, 2007, was:

(1) Nonforested; and

(2) Actively managed as agricultural land or fallow, as evidenced by records which must be traceable to the land in question, which must include one of the following:

(i) Records of sales of planted crops, crop residue, or livestock, or records of purchases for land treatments such as fertilizer, weed control, or seeding.

(ii) A written management plan for agricultural purposes.

(iii) Documented participation in an agricultural management program administered by a Federal, state, or local government agency.

(iv) Documented management in accordance with a certification program for agricultural products.

*Exporter of renewable fuel* means all buyers, sellers, and owners of the renewable fuel in any transaction that results in renewable fuel being transferred from a covered location to a destination outside of the covered locations.

*Facility* means all of the activities and equipment associated with the production of renewable fuel, biogas, treated biogas, RNG, or a biointermediate—starting from the point of delivery of feedstock material to the point of final storage of the end product—that are located on one property and are under the control of the same person (or persons under common control).

*Fallow* means cropland, pastureland, or land enrolled in the Conservation Reserve Program (administered by the U.S. Department of Agriculture's Farm Service Agency) that is intentionally left idle to regenerate for future agricultural purposes with no seeding or planting, harvesting, mowing, or treatment during the fallow period.

*Feedstock aggregator* means any person who collects feedstock from feedstock suppliers or other feedstock aggregators and distributes such feedstock to a renewable fuel producer, biointermediate producer, or other feedstock aggregator.

*Feedstock supplier* means any person who generates and supplies feedstock to a feedstock aggregator, renewable fuel producer, biogas producer, or biointermediate producer.

*Foreign biogas producer* means any person who owns, leases, operates, controls, or supervises a biogas production facility outside of the United States.

*Foreign ethanol producer* means a foreign renewable fuel producer who produces ethanol for use in transportation fuel, heating oil, or jet fuel but who does not add ethanol denaturant to their product as specified in paragraph (2) of the definition of ''renewable fuel'' in this section.

*Foreign renewable fuel producer* means a person from a foreign country or from an area outside the covered location who produces renewable fuel for use in transportation fuel, heating oil, or jet fuel for export to the covered location. Foreign ethanol producers are considered foreign renewable fuel producers.

*Foreign RNG producer* means any person who owns, leases, operates, controls, or supervises an RNG production facility outside of the United States.

*Forestland* is generally undeveloped land covering a minimum area of 1 acre upon which the primary vegetative species are trees, including land that formerly had such tree cover and that will be regenerated and tree plantations. Tree-covered areas in intensive agricultural crop production settings, such as fruit orchards, or tree-covered areas in urban settings, such as city parks, are not considered forestland.

*Free fatty acid (FFA) feedstock* means a biointermediate that is composed of at least 50 percent free fatty acids. FFA feedstock must not include any free fatty acids from the refining of crude palm oil.

*Fuel for use in an ocean-going vessel* means, for this part only:

(1) Any marine residual fuel (whether burned in ocean waters, Great Lakes, or other internal waters);

(2) Emission Control Area (ECA) marine fuel, pursuant to § 80.2 and 40 CFR 1090.80 (whether burned in ocean waters, Great Lakes, or other internal waters); and

(3) Any other fuel intended for use only in ocean-going vessels.

*Gasoline* means any of the following:

(1) Any fuel sold in the United States for use in motor vehicles and motor vehicle engines, and commonly or commercially known or sold as gasoline.

(2) For purposes of subpart M of this part, any and all of the products specified at § 80.1407(c).

*Gasoline blendstock* or *component* means any liquid compound that is blended with other liquid compounds to produce gasoline.

*Gasoline blendstock for oxygenate blending (BOB)* has the meaning given in 40 CFR 1090.80.

*Gasoline treated as blendstock (GTAB)* means imported gasoline that is excluded from an import facility's compliance calculations, but is treated as blendstock in a related refinery that includes the GTAB in its refinery compliance calculations.

*Glycerin* means a coproduct from the production of biodiesel that primarily contains glycerol.

*Heating oil* means any of the following:

(1) Any No. 1, No. 2, or non-petroleum diesel blend that is sold for use in furnaces, boilers, and similar applications and which is commonly or commercially known or sold as heating oil, fuel oil, and similar trade names, and that is not jet fuel, kerosene, or MVNRLM diesel fuel.

(2) Any fuel oil that is used to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort. The fuel oil must be liquid at STP and contain no more than 2.5% mass solids.

*Importer* means any person who imports transportation fuel or renewable fuel into the covered location from an area outside of the covered location.

*Independent third-party auditor* means a party meeting the requirements of § 80.1471(b) that conducts QAP audits and verifies RINs, biointermediates, or biogas.

*Interim period* means the period between February 21, 2013, and December 31, 2014.

*Jet fuel* means any distillate fuel used, intended for use, or made available for use in aircraft.

*Kerosene* means any No.1 distillate fuel commonly or commercially sold as kerosene.

*Liquefied petroleum gas (LPG)* means a liquid hydrocarbon fuel that is stored under pressure and is composed primarily of species that are gases at atmospheric conditions (temperature = 25 °C and pressure = 1 atm), excluding natural gas.

*Locomotive engine* means an engine used in a locomotive as defined under 40 CFR 92.2.

*Marine engine* has the meaning given in 40 CFR 1042.901.

*Membrane separation* means the process of dehydrating ethanol to fuel grade (>99.5% purity) using a hydrophilic membrane.

*Mixed digester* means an anaerobic digester that has received feedstocks under both an approved pathway with D code 3 or 7 and an approved pathway with D code 5 during the current calendar month or the previous two calendar months.

*Motor vehicle* has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550(2)).

*Municipal wastewater treatment facility digester* means an anaerobic digester that processes only municipal wastewater treatment plant sludge with an adjusted cellulosic content of at least 75%.

*MVNRLM diesel fuel* means any diesel fuel or other distillate fuel that is used, intended for use, or made available for use in motor vehicles or motor vehicle engines, or as a fuel in any nonroad diesel engines, including locomotive and marine diesel engines, except the following: Distillate fuel with a T90 at or above 700 °F that is used only in Category 2 and 3 marine engines is not MVNRLM diesel fuel, and ECA marine fuel is not MVNRLM diesel fuel (note that fuel that conforms to the requirements of MVNRLM diesel fuel is excluded from the definition of ''ECA marine fuel'' in this section without regard to its actual use). Use the distillation test method specified in 40 CFR 1065.1010 to determine the T90 of the fuel.

(1) Any diesel fuel that is sold for use in stationary engines that are required to meet the requirements of 40 CFR 1090.300, when such provisions are applicable to nonroad engines, is considered MVNRLM diesel fuel.

(2) [Reserved]

*Nameplate capacity* means the peak design capacity of a facility for the purposes of registration of a facility under this part.

*Naphtha* means a blendstock or fuel blending component falling within the boiling range of gasoline, which is composed of only hydrocarbons, is commonly or commercially known as naphtha, and is used to produce gasoline or E85 (as defined in 40 CFR 1090.80) through blending.

*Natural gas* means a fuel whose primary constituent is methane. Natural gas includes RNG.

*Natural gas commercial pipeline system* means one or more connected pipelines that transport natural gas that meets all the following:

(1) The natural gas originates from multiple parties.

(2) The natural gas meets specifications set by the pipeline owner or operator.

(3) The natural gas is delivered to multiple parties in the covered location.

*Neat renewable fuel* is a renewable fuel to which 1% or less of gasoline (as defined in this section) or diesel fuel has been added.

*Non-ester renewable diesel* or *renewable diesel* means renewable fuel that is not a mono-alkyl ester and that is either:

(1) A fuel or fuel additive that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.12) and can be used in an engine designed to operate on conventional diesel fuel; or

(2) A fuel or fuel additive that is registered under 40 CFR part 79 and can be used in an engine designed to operate using conventional diesel fuel.

*Nonforested land* means land that is not forestland.

*Non-petroleum diesel* means a diesel fuel that contains at least 80 percent mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats.

*Non-qualifying fuel use* means a use of renewable fuel in an application other than transportation fuel, heating oil, or jet fuel.

*Non-renewable component* means any material (or any portion thereof) blended into biogas or RNG that does not meet the definition of renewable biomass.

*Non-renewable feedstock* means a feedstock (or any portion thereof) that does not meet the definition of renewable biomass or biointermediate.

*Non-RIN-generating foreign producer* means a foreign renewable fuel producer that has been registered by EPA to produce renewable fuel for which RINs have not been generated.

*Nonroad diesel engine* means an engine that is designed to operate with diesel fuel that meets the definition of nonroad engine in 40 CFR 1068.30, including locomotive and marine diesel engines.

*Nonroad vehicle* has the meaning given in Section 216(11) of the Clean Air Act (42 U.S.C. 7550(11)).

*Obligated party* means any refiner that produces gasoline or diesel fuel within the covered location, or any importer that imports gasoline or diesel fuel into the covered location, during a compliance period. A party that simply blends renewable fuel into gasoline or diesel fuel, as specified in § 80.1407(c) or (e), is not an obligated party.

*Ocean-going vessel* means vessels that are equipped with engines meeting the definition of ''Category 3'' in 40 CFR 1042.901.

*Oxygenate* means any substance which, when added to gasoline, increases the oxygen content of that gasoline. Lawful use of any of the substances or any combination of these substances requires that they be ''substantially similar'' under section 211(f)(1) of the Clean Air Act (42 U.S.C. 7545(f)(1)), or be permitted under a waiver granted by EPA under the authority of section 211(f)(4) of the Clean Air Act (42 U.S.C. 7545(f)(4)).

*Oxygenated gasoline* means gasoline which contains a measurable amount of oxygenate.

*Pastureland* is land managed for the production of select indigenous or introduced forage plants for livestock grazing or hay production, and to prevent succession to other plant types.

*Permitted capacity* means 105% of the maximum permissible volume output of renewable fuel that is allowed under operating conditions specified in the most restrictive of all applicable preconstruction, construction and operating permits issued by regulatory authorities (including local, regional, state or a foreign equivalent of a state, and federal permits, or permits issued by foreign governmental agencies) that govern the construction and/or operation of the renewable fuel facility, based on an annual volume output on a calendar year basis. If the permit specifies maximum rated volume output on an hourly basis, then annual volume output is determined by multiplying the hourly output by 8,322 hours per year.

(1) For facilities that commenced construction prior to December 19, 2007, the permitted capacity is based on permits issued or revised no later than December 19, 2007.

(2) For facilities that commenced construction after December 19, 2007 and before January 1, 2010 that are fired with natural gas, biomass, or a combination thereof, the permitted capacity is based on permits issued or revised no later than December 31, 2009.

(3) For facilities other than those specified in paragraphs (1) and (2) of this definition, permitted capacity is based on the most recent applicable permits.

*Pipeline interconnect* means the physical injection or withdrawal point where RNG is injected or withdrawn into or from the natural gas commercial pipeline system.

*Planted crops* are all annual or perennial agricultural crops from existing agricultural land that may be used as feedstocks for renewable fuel, such as grains, oilseeds, sugarcane, switchgrass, prairie grass, duckweed, and other species (but not including algae species or planted trees), providing that they were intentionally applied by humans to the ground, a growth medium, a pond or tank, either by direct application as seed or plant, or through intentional natural seeding or vegetative propagation by mature plants introduced or left undisturbed for that purpose.

*Planted trees* are trees harvested from a tree plantation.

*Pre-commercial thinnings* are trees, including unhealthy or diseased trees, removed to reduce stocking to concentrate growth on more desirable, healthy trees, or other vegetative material that is removed to promote tree growth.

*Professional liability insurance* means insurance coverage for liability arising out of the performance of professional or business duties related to a specific occupation, with coverage being tailored to the needs of the specific occupation. Examples include abstracters, accountants, insurance adjusters, architects, engineers, insurance agents and brokers, lawyers, real estate agents, stockbrokers, and veterinarians. For purposes of this definition, professional liability insurance does not include directors and officers liability insurance.

*Q–RIN* means a RIN verified by a registered independent third-party auditor using a QAP that has been approved under § 80.1469(c) following the audit process specified in § 80.1472.

*Quality assurance audit* means an audit of a renewable fuel production facility or biointermediate production facility conducted by an independent third-party auditor in accordance with a QAP that meets the requirements of §§ 80.1469, 80.1472, and 80.1477.

*Quality assurance plan (QAP)* means the list of elements that an independent third-party auditor will check to verify that the RINs generated by a renewable fuel producer or importer are valid or to verify the appropriate production of a biointermediate. A QAP includes both general and pathway specific elements.

*Raw starch hydrolysis* means the process of hydrolyzing corn starch into simple sugars at low temperatures, generally not exceeding 100 °F (38 °C), using enzymes designed to be effective under these conditions.

*Refiner* means any person who owns, leases, operates, controls, or supervises a refinery.

*Refinery* means any facility, including but not limited to, a plant, tanker truck, or vessel where gasoline or diesel fuel is produced, including any facility at which blendstocks are combined to produce gasoline or diesel fuel, or at which blendstock is added to gasoline or diesel fuel.

*Reformulated gasoline (RFG)* means any gasoline whose formulation has been certified under 40 CFR 1090.1000(b), and which meets each of the standards and requirements prescribed under 40 CFR 1090.220.

*Reformulated gasoline blendstock for oxygenate blending (RBOB)* means a petroleum product that, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated gasoline, and to which the specified type and percentage of oxygenate is added other than by the refiner or importer of the RBOB at the refinery or import facility where the RBOB is produced or imported.

*Renewable biomass* means each of the following (including any incidental, de minimis contaminants that are impractical to remove and are related to customary feedstock production and transport):

(1) Planted crops and crop residue harvested from existing agricultural land cleared or cultivated prior to December 19, 2007 and that was nonforested and either actively managed or fallow on December 19, 2007.

(2) Planted trees and tree residue from a tree plantation located on non-federal land (including land belonging to an Indian tribe or an Indian individual that is held in trust by the U.S. or subject to a restriction against alienation imposed

by the U.S.) that was cleared at any time prior to December 19, 2007 and actively managed on December 19, 2007.

(3) Animal waste material and animal byproducts.

(4) Slash and pre-commercial thinnings from non-federal forestland (including forestland belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States) that is not ecologically sensitive forestland.

(5) Biomass (organic matter that is available on a renewable or recurring basis) obtained from within 200 feet of buildings and other areas regularly occupied by people, or of public infrastructure, in an area at risk of wildfire.

(6) Algae.

(7) Separated yard waste or food waste, including recycled cooking and trap grease.

*Renewable compressed natural gas* or *renewable CNG* means biogas, treated biogas, or RNG that is compressed for use as transportation fuel and meets the definition of renewable fuel.

*Renewable electricity* means electricity that meets the definition of renewable fuel.

*Renewable fuel* means a fuel that meets all the following requirements:

(1)(i) Fuel that is produced either from renewable biomass or from a biointermediate produced from renewable biomass.

(ii) Fuel that is used in the covered location to replace or reduce the quantity of fossil fuel present in a transportation fuel, heating oil, or jet fuel.

(iii) Has lifecycle greenhouse gas emissions that are at least 20 percent less than baseline lifecycle greenhouse gas emissions, unless the fuel is exempt from this requirement pursuant to § 80.1403.

(2) Ethanol covered by this definition must be denatured using an ethanol denaturant as required in 27 CFR parts 19 through 21. Any volume of ethanol denaturant added to the undenatured ethanol by a producer or importer in excess of 2 volume percent must not be included in the volume of ethanol for purposes of determining compliance with the requirements of this part.

*Renewable gasoline* means renewable fuel produced from renewable biomass that is composed of only hydrocarbons and that meets the definition of gasoline.

*Renewable gasoline blendstock* means a blendstock produced from renewable biomass that is composed of only hydrocarbons and which meets the definition of gasoline blendstock in § 80.2.

*Renewable Identification Number (RIN)* is a unique number generated to represent a volume of renewable fuel pursuant to §§ 80.1425 and 80.1426.

(1) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel used for compliance purposes pursuant to § 80.1427 to satisfy a renewable volume obligation.

(2) *Batch-RIN* is a RIN that represents multiple gallon-RINs.

*Renewable liquefied natural gas* or *renewable LNG* means biogas, treated biogas, or RNG that is liquified (*i.e.,* it is cooled below its boiling point) for use as transportation fuel and meets the definition of renewable fuel.

*Renewable natural gas (RNG)* means a product that meets all the following requirements:

(1) It is produced from biogas.

(2) It does not require removal of additional components to be suitable for injection into the natural gas commercial pipeline system.

(3) It is used to produce renewable fuel.

*Residual fuel* means a petroleum fuel that can only be used in diesel engines if it is preheated before injection. For example, No. 5 fuels, No. 6 fuels, and RM grade marine fuels are residual fuels. Note: Residual fuels do not necessarily require heating for storage or pumping.

*Responsible corporate officer (RCO)* has the meaning given in 40 CFR 1090.80.

*Retail outlet* means any establishment at which gasoline, diesel fuel, natural gas or liquefied petroleum gas is sold or offered for sale for use in motor vehicles or nonroad engines, including locomotive or marine engines.

*Retailer* means any person who owns, leases, operates, controls, or supervises a retail outlet.

*RIN-generating foreign producer* means a foreign renewable fuel producer that has been registered by EPA to generate RINs for renewable fuel it produces.

*RIN generator* means any party allowed to generate RINs under this part.

*RIN-less RNG* means RNG produced by a foreign RNG producer and for which RINs were not generated by the foreign RNG producer.

*RNG importer* means any person who imports RNG into the covered location and generates RINs for the RNG as specified in § 80.125.

*RNG producer* means any person who owns, leases, operates, controls, or supervises an RNG production facility.

*RNG production facility* means a facility where biogas is upgraded to RNG under an approved pathway.

*RNG RIN separator* means any person registered to separate RINs for RNG under § 80.125(d).

*RNG used as a feedstock* or *RNG as a feedstock* means any RNG used to produce renewable fuel under § 80.125.

*Separated food waste* means a feedstock stream consisting of food waste kept separate since generation from other waste materials, and which includes food and beverage production waste and post-consumer food and beverage waste.

*Separated municipal solid waste* or *separated MSW* means material remaining after separation actions have been taken to remove recyclable paper, cardboard, plastics, rubber, textiles, metals, and glass from municipal solid waste, and which is composed of both cellulosic and non-cellulosic materials.

*Separated RIN* means a RIN with a K code of 2 that has been separated from a volume of renewable fuel or RNG pursuant to § 80.1429.

*Separated yard waste* means a feedstock stream consisting of yard waste kept separate since generation from other waste materials.

*Slash* is the residue, including treetops, branches, and bark, left on the ground after logging or accumulating as a result of a storm, fire, delimbing, or other similar disturbance.

*Small refinery* means a refinery for which the average aggregate daily crude oil throughput (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

*Soapstock* means an emulsion, or the oil obtained from separation of that emulsion, produced by washing oils listed as a feedstock in an approved pathway with water.

*Standard temperature and pressure (STP)* means 60 degrees Fahrenheit and 1 atmosphere of pressure.

*Transportation fuel* means fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except fuel for use in ocean-going vessels).

*Treated biogas* means a product that meets all the following requirements:

(1) It is produced from biogas.

(2) It does not require removal of additional components to be suitable for its designated use (*e.g.,* as a biointermediate or to produce biogas-derived renewable fuel).

(3) It is used in a biogas closed distribution system as a biointermediate or to produce biogas-derived renewable fuel.

*Tree plantation* is a stand of no less than 1 acre composed primarily of trees established by hand- or machine-planting of a seed or sapling, or by coppice growth from the stump or root of a tree that was hand- or machine-planted. Tree plantations must have been cleared prior to December 19, 2007 and must have been actively managed on December 19, 2007, as evidenced by records which must be traceable to the land in question, which must include:

(1) Sales records for planted trees or tree residue together with other written documentation connecting the land in question to these purchases;

(2) Purchasing records for seeds, seedlings, or other nursery stock together with other written documentation connecting the land in question to these purchases;

(3) A written management plan for silvicultural purposes;

(4) Documentation of participation in a silvicultural program sponsored by a Federal, state, or local government agency;

(5) Documentation of land management in accordance with an agricultural or silvicultural product certification program;

(6) An agreement for land management consultation with a professional forester that identifies the land in question; or

(7) Evidence of the existence and ongoing maintenance of a road system or other physical infrastructure designed and maintained for logging use, together with one of the above-mentioned documents.

*Tree residue* is slash and any woody residue generated during the processing of planted trees from tree plantations for use in lumber, paper, furniture, or other applications, provided that such woody residue is not mixed with similar residue from trees that do not originate in tree plantations.

*Undenatured ethanol* means a liquid that meets one of the definitions in paragraph (1) of this definition:

(1)(i) Ethanol that has not been denatured as required in 27 CFR parts 19 through 21.

(ii) Specially denatured alcohol as defined in 27 CFR 21.11.

(2) Undenatured ethanol is not renewable fuel.

*United States* has the meaning given in 40 CFR 1090.80.

*Verification status* means a description of whether biogas, treated biogas, RNG, or a RIN has been verified under an EPA-approved quality assurance plan.

*Verified RIN* means a RIN generated by a renewable fuel producer that was subject to a QAP audit executed by an independent third-party auditor, and determined by the independent third-party auditor to be valid. Verified RINs includes A–RINs, B–RINs, and Q–RINs.

*Wholesale purchaser-consumer* means any person that is an ultimate consumer of gasoline, diesel fuel, natural gas, or liquefied petroleum gas and which purchases or obtains gasoline, diesel fuel, natural gas or liquefied petroleum gas from a supplier for use in motor vehicles or nonroad engines, including locomotive or marine engines and, in the case of gasoline, diesel fuel, or liquefied petroleum gas, receives delivery of that product into a storage tank of at least 550-gallon capacity substantially under the control of that person.

■ 3. Add § 80.3 to read as follows:

**§ 80.3 Acronyms and abbreviations.**

| | |
|---|---|
| AB | Advanced biofuel. |
| APHA | American Public Health Association. |
| API | American Petroleum Institute. |
| ASTM | ASTM International. |
| BBD | Biomass-based diesel. |
| BMP | Best management practices. |
| BOB | Gasoline before oxygenate blending. |
| CAA | Clean Air Act. |
| CB | Cellulosic biofuel. |
| CBOB | Conventional gasoline before oxygenate blending. |
| CF | Converted fraction. |
| CG | Conventional gasoline. |
| CHP | Combined heat and power. |
| CNG | Compressed natural gas. |
| CPI–U | Consumer Price Index for All Urban Consumers. |
| ECA | Emission Control Area. |
| EDRR | Early detection and rapid response. |
| EIA | Energy Information Administration. |
| EMTS | EPA Moderated Transaction System. |
| EPA | Environmental Protection Agency. |
| EqV | Equivalence value. |
| ERVO | Exporter renewable volume obligation. |
| FE | Feedstock energy. |
| FFA | Free-fatty acid. |
| GC | Gas chromatography. |
| GHG | Greenhouse gas. |
| GTAB | Gasoline treated as blendstock. |
| HACCP | Hazard Analysis Critical Control Point. |
| HHV | Higher heating value. |
| IBR | Incorporation by reference. |
| ID | Identification. |
| kWh | Kilowatt-hour. |
| LE | Limited exemption. |
| LHV | Lower heating value. |
| LNG | Liquified natural gas. |
| MSW | Municipal solid waste. |
| MVNRLM | Motor vehicle, nonroad, locomotive, or marine. |
| NARA | National Archives and Records Administration. |
| NTDF | Non-transportation 15 ppm distillate fuel. |
| PIR | Potentially invalid RIN. |
| $PM_{10}$ | Particulate matter generally 10 micrometers or smaller. |
| $PM_{2.5}$ | Particulate matter generally 2.5 micrometers or smaller. |
| PTD | Product transfer document. |
| QAP | Quality assurance plan. |
| RBOB | Reformulated gasoline before oxygenate blending. |
| RCO | Responsible corporate officer. |
| RF | Renewable fuel. |
| RFS | Renewable Fuel Standard. |
| RFS–FRRF | RFS foreign refiner renewable fuel. |
| RIN | Renewable identification number. |
| RNG | Renewable natural gas. |
| RVO | Renewable volume obligation. |
| STP | Standard temperature and pressure. |
| U.S. | United States. |
| ULSD | Ultra-low-sulfur diesel fuel. |
| USDA | United States Department of Agriculture. |
| UTC | Coordinated Universal Time. |
| VCSB | Voluntary consensus standards body. |

**§ 80.4 [Amended]**

■ 4. Amend § 80.4 by removing the text ''The Administrator or his authorized representative'' and adding in its place the text ''EPA''.

■ 5. Amend § 80.7 by:

■ a. Revising paragraph (a) introductory text;

■ b. In paragraph (b), removing the text ''the Administrator, the Regional Administrator, or their delegates'' and adding in its place the text ''EPA''; and

■ c. Revising the first sentence of paragraph (c).

The revisions read as follows:

**§ 80.7 Requests for information.**

(a) When EPA has reason to believe that a violation of section 211(c) or section 211(n) of the Clean Air Act and the regulations thereunder has occurred, EPA may require any refiner, distributor, wholesale purchaser-consumer, or retailer to report the following information regarding receipt, transfer, delivery, or sale of gasoline represented to be unleaded gasoline and to allow the reproduction of such information at all reasonable times.

* * * * *

(c) Any refiner, distributor, wholesale purchaser-consumer, retailer, or importer must provide such other information as EPA may reasonably require to enable the Agency to determine whether such refiner, distributor, wholesale purchaser-consumer, retailer, or importer has acted or is acting in compliance with sections 211(c) and 211(n) of the Clean Air Act and the regulations thereunder and must, upon request of EPA, produce and allow reproduction of any relevant records at all reasonable times. * * *

* * * * *

■ 6. Revise § 80.8 to read as follows:

**§ 80.8 Sampling methods for gasoline, diesel fuel, fuel additives, and renewable fuels.**

(a) *Manual sampling.* Manual sampling of tanks and pipelines shall be performed according to the applicable procedures specified in ASTM D4057 (incorporated by reference, see § 80.12).

(b) *Automatic sampling.* Automatic sampling of petroleum products in pipelines shall be performed according to the applicable procedures specified in ASTM D4177 (incorporated by reference, see § 80.12).

(c) *Sampling and sample handling for volatility measurement.* Samples to be analyzed for Reid Vapor Pressure (RVP) shall be collected and handled according to the applicable procedures specified in ASTM D5842 (incorporated by reference, see § 80.12).

(d) *Sample compositing.* Composite samples shall be prepared using the applicable procedures specified in ASTM D5854 (incorporated by reference, see § 80.12).

■ 7. Revise § 80.9 to read as follows:

**§ 80.9 Rounding.**

(a) Test results and calculated values reported to EPA under this part must be rounded according to 40 CFR 1090.50(a) through (d).

(b) Calculated values under this part may only be rounded when reported to EPA.

(c) Reported values under this part must be submitted using forms and procedures specified by EPA.

■ 8. Add § 80.12 to subpart A to read as follows:

**§ 80.12 Incorporation by reference.**

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved incorporation by reference (IBR) material is available for inspection at U.S. EPA and at the National Archives and Records Administration (NARA). Contact U.S. EPA at: U.S. EPA, Air and Radiation Docket and Information Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460; (202) 566–1742. For information on the availability of this material at NARA, visit: *www.archives.gov/federal-register/cfr/ibr-locations.html* or email *fr.inspection@nara.gov.* The material may be obtained from the following sources:

(a) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001–5571; (202) 682–8000; *www.api.org.*

(1) API MPMS 14.1–2016, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016 (''API MPMS 14.1''); IBR approved for § 80.155(b).

(2) API MPMS 14.3.1–2012, Manual of Petroleum Measurement Standards Chapter 14.3.1—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022 (''API MPMS 14.3.1''); IBR approved for § 80.155(a).

(3) API MPMS 14.3.2–2016, Manual of Petroleum Measurement Standards Chapter 14.3.2—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016 (''API MPMS 14.3.2''); IBR approved for § 80.155(a).

(4) API MPMS 14.3.3–2013, Manual of Petroleum Measurement Standards Chapter 14.3.3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021 (''API MPMS 14.3.3''); IBR approved for § 80.155(a).

(5) API MPMS 14.3.4–2019, Manual of Petroleum Measurement Standards Chapter 14.3.4—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019 (''API MPMS 14.3.4''); IBR approved for § 80.155(a).

(6) API MPMS 14.12–2017, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluid Measurement Section 12—Measurement of Gas by Vortex Meters, 1st Edition, March 2017 (''API MPMS 14.12''); IBR approved for § 80.155(a).

**Note 1 to paragraph (a):** API MPMS 14.3.1, 14.3.2, 14.3.3, and 141.3.4, are co-published as AGA Report 3, Parts 1, 2, 3, and 4, respectively.

(b) American Public Health Association (APHA), 1015 15th Street NW, Washington, DC 20005; (202) 777–2742; *www.standardmethods.org.*

(1) SM 2540, revised June 10, 2020; IBR approved for § 80.155(c).

(2) [Reserved]

(c) ASTM International (ASTM), 100 Barr Harbor Dr., P.O. Box C700, West Conshohocken, PA 19428–2959; (877) 909–2786; *www.astm.org.*

(1) ASTM D975–21, Standard Specification for Diesel Fuel, approved August 1, 2021 (''ASTM D975''); IBR approved for §§ 80.2; 80.1426(f); 80.1450(b); 80.1451(b); 80.1454(l).

(2) ASTM D1250–19e1, Standard Guide for the Use of the Joint API and ASTM Adjunct for Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils: API MPMS Chapter 11.1, approved May 1, 2019 (''ASTM D1250''); IBR approved for § 80.1426(f).

(3) ASTM D3588–98 (Reapproved 2017)e1, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, approved April 1, 2017 (''ASTM D3588''); IBR approved for § 80.155(b) and (f).

(4) ASTM D4057–12, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved December 1, 2012 (''ASTM D4057''); IBR approved for § 80.8(a).

(5) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved May 1, 2010 (''ASTM D4177''); IBR approved for § 80.8(b).

(6) ASTM D4442–20, Standard Test Methods for Direct Moisture Content Measurement of Wood and Wood-Based Materials, approved March 1, 2020 (''ASTM D4442''); IBR approved for § 80.1426(f).

(7) ASTM D4444–13 (Reapproved 2018), Standard Test Method for Laboratory Standardization and Calibration of Hand-Held Moisture Meters, reapproved July 1, 2018 (''ASTM D4444''); IBR approved for § 80.1426(f).

(8) ASTM D4888–20, Standard Test Method for Water Vapor in Natural Gas Using Length-of-Stain Detector Tubes, approved December 15, 2020 (''ASTM D4888''); IBR approved for § 80.155(b).

(9) ASTM D5504–20, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, approved

November 1, 2020 (''ASTM D5504''); IBR approved for § 80.155(b).

(10) ASTM D5842–14, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved January 15, 2014 (''ASTM D5842''); IBR approved for § 80.8(c).

(11) ASTM D5854–96 (Reapproved 2010), Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products, approved May 1, 2010 (''ASTM D5854''); IBR approved for § 80.8(d).

(12) ASTM D6751–20a, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved August 1, 2020 (''ASTM D6751''); IBR approved for § 80.2.

(13) ASTM D6866–22, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved March 15, 2022 (''ASTM D6866''); IBR approved for §§ 80.155(b); 80.1426(f); 80.1430(e).

(14) ASTM D7164–21, Standard Practice for On-line/At-line Heating Value Determination of Gaseous Fuels by Gas Chromatography, approved April 1, 2021 (''ASTM D7164''); IBR approved for § 80.155(a).

(15) ASTM D8230–19, Standard Test Method for Measurement of Volatile Silicon-Containing Compounds in a Gaseous Fuel Sample Using Gas Chromatography with Spectroscopic Detection, approved June 1, 2019 (''ASTM D8230''); IBR approved for § 80.155(b).

(16) ASTM E711–87 (Reapproved 2004), Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, reapproved 2004 (''ASTM E711''); IBR approved for § 80.1426(f).

(17) ASTM E870–82 (Reapproved 2019), Standard Test Methods for Analysis of Wood Fuels, reapproved April 1, 2019 (''ASTM E870''); IBR approved for § 80.1426(f).

(d) European Committee for Standardization (CEN), Rue de la Science 23, B–1040 Brussels, Belgium; + 32 2 550 08 11; *www.cencenelec.eu.*

(1) EN 17526:2021(E), Gas meter—Thermal-mass flow-meter based gas meter, approved July 11, 2021 (''EN 17526''); IBR approved for § 80.155(a).

(2) [Reserved]

■ 9. Add subpart E, consisting of §§ 80.100 through 80.185, to read as follows:

**Subpart E—Biogas-Derived Renewable Fuel**

Sec.



**§ 80.100 Scope and application.**

(a) *Applicability.*

(1) The provisions of this subpart E apply to all the following:

(i) Biogas.

(ii) Treated biogas.

(iii) Biogas-derived renewable fuel.

(iv) RNG used to produce a biogas-derived renewable fuel.

(v) RINs generated for RNG or a biogas-derived renewable fuel.

(2) This subpart also specifies requirements for specified parties that engage in activities associated with the production, distribution, transfer, or use of biogas, treated biogas, biogas-derived renewable fuel, RNG used to produce a biogas-derived renewable fuel, and RINs generated for a biogas-derived renewable fuel under the RFS program.

(b) *Relationship to other fuels regulations.* (1) The provisions of subpart M of this part also apply to the parties and products regulated under this subpart E.

(2) The provisions of 40 CFR part 1090 include provisions that may apply to the parties and products regulated under this subpart E.

(3) Parties and products subject to this subpart E may need to register a fuel or fuel additive under 40 CFR part 79.

(c) *Geographic scope.* RINs must only be generated for biogas-derived renewable fuel used in the covered location.

(d) *Implementation dates.* (1) *General.* The provisions of this subpart E apply beginning July 1, 2024, unless otherwise specified.

(2) *Registration.* (i) Parties not registered to generate RINs under § 80.1426(f)(10)(ii) or (11)(ii) prior to July 1, 2024, must register with EPA under § 80.135. EPA will not accept registration submissions for the generation of RINs under § 80.1426(f)(10)(ii) and (11)(ii) on or after July 1, 2024.

(ii) Parties registered to generate RINs under § 80.1426(f)(10)(ii) or (11)(ii) must submit updated registration information under § 80.135 no later than October 1, 2024.

(iii) Independent third-party engineers may conduct engineering reviews for parties required to register under § 80.135 prior to July 1, 2024, as long as the engineering review satisfies all applicable requirements under §§ 80.135 and 80.1450.

(3) *Generation of RINs for RNG.* RNG producers may only generate RINs for RNG produced on or after July 1, 2024, as specified in § 80.125.

(4) *Generation of RINs for renewable CNG/LNG for previously registered facilities.* (i)(A) Prior to January 1, 2025, RIN generators may generate RINs as specified in § 80.1426(f)(10)(ii) or (11)(ii) for renewable CNG/LNG produced from a facility covered by a registration accepted by EPA under § 80.1450(b) prior to July 1, 2024.

(B) Biogas or RNG produced under a registration accepted by EPA under § 80.1450(b) for the generation of RINs as specified in § 80.1426(f)(10)(ii) or (11)(ii) prior to July 1, 2024, may only be used to generate RINs for renewable CNG/LNG.

(ii) For biogas produced on or after January 1, 2025, biogas closed distribution system RIN generators must generate RINs for renewable CNG/LNG as specified in § 80.130.

(5) *Generation of RINs for renewable fuel produced from biogas used as a biointermediate.* Renewable fuel producers must only generate RINs for renewable fuel produced from biogas used as a biointermediate produced on or after July 1, 2024.

**§ 80.105 Biogas producers.**

(a) *General requirements.* (1) Any biogas producer that produces biogas for use to produce RNG or a biogas-derived renewable fuel, or that produces biogas used as a biointermediate, must comply with the requirements of this section.

(2) The biogas producer must also comply with all other applicable requirements of this part and 40 CFR part 1090.

(3) If the biogas producer meets the definition of more than one type of regulated party under this part or 40 CFR part 1090, the biogas producer must comply with the requirements applicable to each of those types of regulated parties.

(4) The biogas producer must comply with all applicable requirements of this part, regardless of whether the requirements are identified in this section.

(b) *Registration.* The biogas producer must register with EPA under §§ 80.135, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The biogas producer must submit reports to EPA under §§ 80.140 and 80.1451, as applicable.

(d) *Recordkeeping.* The biogas producer must create and maintain records under §§ 80.145 and 80.1454.

(e) *PTDs.* On each occasion when the biogas producer transfers title of any biogas, the transferor must provide to the transferee PTDs under § 80.150.

(f) *Sampling, testing, and measurement.*

(1) All sampling, testing, and measurements must be done in accordance with § 80.155.

(2)(i) A biogas producer must measure the volume of biogas, in Btu HHV, prior to converting biogas to any of the following:

(A) RNG.

(B) Treated biogas.

(C) Biointermediate.

(D) Biogas-derived renewable fuel.

(E) Process heat or energy under § 80.1426(f)(12) or (13).

(ii) Except for biogas produced from a mixed digester, a biogas producer must measure the volume of biogas, in Btu HHV, for each batch pathway prior to mixing with biogas produced under a different batch pathway or with non-qualifying gas.

(iii) For biogas produced from a mixed digester, a biogas producer must do all the following for each mixed digester:

(A) Measure the volume of biogas, in Btu HHV, prior to mixing with any other gas.

(B) Measure the daily mass of the cellulosic biogas feedstock, in pounds, added to the mixed digester.

(C) Collect a daily representative sample of each cellulosic biogas feedstock and test for total solids and volatile solids as specified in § 80.155(c).

(D) Measure and calculate the digester operating conditions as specified in § 80.155(d).

(iv) A biogas producer must measure each volume of gas containing biogas, in Btu HHV, that leaves the facility.

(g) *Foreign biogas producer requirements.* A foreign biogas producer must meet all the requirements that apply to a biogas producer under this part, as well as the additional requirements for foreign biogas producers specified in § 80.160.

(h) *Attest engagements.* The biogas producer must submit annual attest engagement reports to EPA under §§ 80.165 and 80.1464 using procedures specified in 40 CFR 1090.1800 and 1090.1805.

(i) *QAP.* Prior to the generation of Q–RINs for a biogas-derived renewable fuel, the biogas producer must meet all applicable requirements specified in § 80.170.

(j) *Batches.* (1) Except for biogas produced from a mixed digester, the batch volume of biogas is the volume of biogas measured under paragraph (f) of this section for a single batch pathway at a single facility for a calendar month, in Btu HHV.

(2) For biogas produced from a mixed digester, the batch volume of biogas must be calculated as follows:

(i) The batch volume of biogas produced under an approved pathway with a D code of 5 must be calculated as follows:

$$V_{BG,D5} = V_{BG} - V_{BG,D3/7}$$

Where:

$V_{BG,D5}$ = The batch volume of biogas for an approved pathway with a D code of 5 for the calendar month, in Btu HHV. If the result of this equation is negative, then $V_{BG,D5,p}$ equals 0.

$V_{BG}$ = The total volume of biogas produced by the mixed digester for the calendar month, in Btu HHV, as measured under paragraph (f)(2)(iii)(A) of this section.

$V_{BG,D3/7}$ = The total batch volume of biogas produced under approved pathways with a D code of 3 or 7 for the calendar month, in Btu HHV, per paragraph (j)(2)(ii) of this section.

(ii) The batch volume of biogas produced under an approved pathway with a D code of 3 or 7 must be calculated as follows:

$$V_{BG,D3/7,p} = BE_{D3/7,i}$$

$V_{BG,D3/7,p}$ = The batch volume of biogas for batch pathway p with a D code of 3 or 7 for the calendar month, in Btu HHV.

$BE_{D3/7,i}$ = The total energy from cellulosic biogas feedstock i that forms energy in the biogas and whose batch pathway has been assigned a D code of 3 or 7 for the calendar month, in Btu HHV, per paragraph (j)(2)(iii) of this section.

(iii) The biogas energy value for each cellulosic biogas feedstock must be calculated as follows:

$$BE_{D3/7,i,j} = M_{i,j} * TS_{i,j} * VS_{i,j} * CF_{i,j}$$

Where:

$BE_{D3/7,i,j}$ = The amount of energy from cellulosic biogas feedstock i that forms energy in the biogas and whose batch pathway has been assigned a D code of 3 or 7 on day j, in Btu HHV.

$M_{i,j}$ = Mass of cellulosic biogas feedstock i, in pounds, measured on day j, per paragraph (f)(2)(iii)(B) of this section.

$TS_{i,j}$ = Total solids of cellulosic biogas feedstock i, as a mass fraction, in pounds total solids per pound feedstock, for the sample obtained on day j, per paragraph (f)(2)(iii)(C) of this section. If sample results are not available, then $TS_{i,j}$ equals 0.

$VS_{i,j}$ = Volatile solids of cellulosic biogas feedstock i, as a mass fraction, in pounds volatile solids per pound total solids, for the sample obtained on day j, per paragraph (f)(2)(iii)(C) of this section. If sample results are not available, then $VS_{i,j}$ equals 0.

$CF_{i,j}$ = Converted fraction in annual average Btu HHV/lb, representing the portion of cellulosic biogas feedstock i that is converted to biomethane by the producer on day j, per paragraph (j)(2)(iv) of this section. If data for digester operating conditions required under paragraph (f)(2)(iii)(D) of this section are outside the range of operating conditions specified in paragraph (j)(2)(v) of this section or such data to determine the operating conditions does not meet the requirements in § 80.155(d), then $CF_{i,j}$ equals 0.

(iv) Biogas producers must use one of the following cellulosic conversion factors, as applicable:

(A) Swine manure: 1,936 Btu HHV/lb.

(B) Bovine manure: 2,077 Btu HHV/lb.

(C) Chicken manure: 3,001 Btu HHV/lb.

(D) Municipal wastewater treatment sludge: 3,479 Btu HHV/lb.

(E) A cellulosic conversion factor accepted at registration under § 80.135(c)(10)(vi).

(v) Applicable operating conditions for the cellulosic converted fractions specified in paragraph (j)(2)(iv) of this section are the following:

(A) For the cellulosic converted fraction values specified in paragraphs (j)(2)(iv)(A) through (D) of this section, the mixed digester must continuously operate above 95 degrees Fahrenheit with hydraulic and solids mean residence times greater than 20 days.

(B) For the cellulosic converted fraction value specified in paragraph (j)(2)(iv)(E) of this section, the mixed digester must operate according to the conditions accepted at registration under § 80.135(c)(10)(vi)(A)(*4*).

(3) The biogas producer must assign a number (the ''batch number'') to each batch of biogas consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the calendar year in which the batch was produced, and a unique number for the batch, beginning with the number one for the first batch produced each calendar year and each subsequent batch during the calendar year being assigned the next sequential number (*e.g.,* 4321–54321–23–000001, 4321–54321–23–000002, etc.).

(k) *Limitations.* (1) For each biogas production facility, the biogas producer must only supply biogas for only one of the following uses:

(i) Production of renewable CNG/LNG via a biogas closed distribution system.

(ii) As a biointermediate via a biogas closed distribution system.

(iii) Production of RNG.

(2) For each biogas production facility producing biogas for use as a biointermediate in a biogas closed distribution system, the biogas producer must only supply biogas or treated biogas to a single renewable fuel production facility.

(3) If the biogas producer operates a municipal wastewater treatment facility digester, the biogas producer must not introduce any feedstocks into that digester that do not contain at least 75% average adjusted cellulosic content.

(4) The transfer and batch segregation limits specified in § 80.1476(g) do not apply.

**§ 80.110 RNG producers, RNG importers, and biogas closed distribution system RIN generators.**

(a) *General requirements.* (1) Any RNG producer, RNG importer, or biogas closed distribution system RIN generator that generates RINs must comply with the requirements of this section.

(2) The RNG producer, RNG importer, or biogas closed distribution system RIN generator must also comply with all other applicable requirements of this part and 40 CFR part 1090.

(3) If the RNG producer, RNG importer, or biogas closed distribution system RIN generator meets the definition of more than one type of regulated party under this part or 40 CFR 1090, the RNG producer, RNG importer, or biogas closed distribution system RIN generator must comply with the requirements applicable to each of those types of regulated parties.

(4) The RNG producer, RNG importer, or biogas closed distribution system RIN generator must comply with all applicable requirements of this part, regardless of whether the requirements are identified in this section.

(5) The transfer and batch segregation limits specified in § 80.1476(g) do not apply.

(b) *Registration.* The RNG producer, RNG importer, or biogas closed distribution system RIN generator must register with EPA under §§ 80.135, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The RNG producer, RNG importer, or biogas closed distribution system RIN generator must submit reports to EPA under §§ 80.140, 80.1451, and 80.1452, as applicable.

(d) *Recordkeeping.* The RNG producer, RNG importer, or biogas closed distribution system RIN generator must create and maintain records under §§ 80.145 and 80.1454.

(e) *PTDs.* On each occasion when the RNG producer, RNG importer, or biogas closed distribution system RIN generator transfers RNG, renewable fuel, or RINs to another party, the transferor must provide to the transferee PTDs under §§ 80.150 and 80.1453, as applicable.

(f) *Sampling, testing, and measurement.* (1) All sampling, testing, and measurements must be done in accordance with § 80.155.

(2)(i) An RNG producer must measure the volume of RNG, in Btu LHV, prior to injection of RNG from the RNG production facility into a natural gas commercial pipeline system.

(ii) An RNG producer that trucks RNG from the RNG production facility to a pipeline interconnect must measure the volume of RNG, in Btu LHV, upon loading and unloading of each truck.

(iii) An RNG producer that injects RNG from an RNG production facility into a natural gas commercial pipeline system must sample and test a representative sample of all the following at least once per calendar year, as applicable:

(A) Biogas used to produce RNG.

(B) RNG before blending with non-renewable components.

(C) RNG after blending with non-renewable components.

(iv) A party that upgrades biogas to treated biogas must separately measure all the following, as applicable:

(A) The volume of biogas, in Btu HHV, used to produce treated biogas, a biogas-derived renewable fuel, or as a biointermediate.

(B) The volume of treated biogas, in Btu HHV, prior to addition of any non-renewable components.

(C) The volume of biointermediate or biogas-derived renewable fuel produced from the biogas or treated biogas. If the biogas-derived renewable fuel is renewable CNG/LNG, then this volume must be measured in both Btu HHV and Btu LHV.

(3) A biogas closed distribution RIN generator must measure renewable CNG/LNG in Btu LHV.

(g) *Foreign RNG producer, RNG importer, and foreign biogas closed distribution system RIN generator requirements.* (1)(i) A foreign RNG producer must meet all the requirements that apply to an RNG producer under this part, as well as the additional requirements for foreign RNG producers specified in § 80.160.

(ii) A foreign RNG producer must either generate RINs under § 80.125 or enter into a contract with an RNG importer as specified in § 80.160(e).

(2) An RNG importer must meet all the requirements specified in § 80.160(h).

(3) A foreign biogas closed distribution system RIN generator must meet all the requirements that apply to a biogas closed distribution system RIN generator under this part, as well as the additional requirements for foreign biogas closed distribution system RIN generators specified in § 80.160 and for RIN-generating foreign renewable fuel producers specified in § 80.1466.

(h) *Attest engagements.* The RNG producer, RNG importer, or biogas closed distribution system RIN generator must submit annual attest engagement reports to EPA under §§ 80.165 and 80.1464 using procedures specified in 40 CFR 1090.1800 and 1090.1805.

(i) *QAP.* Prior to the generation of a Q–RIN for RNG or biogas-derived renewable fuel, the RNG producer, RNG importer, or biogas closed distribution system RIN generator must meet all applicable requirements specified in § 80.170.

(j) *Batches.* (1) A batch of RNG is the total volume of RNG produced at an RNG production facility under a single batch pathway for the calendar month, in Btu LHV, as determined under paragraph (j)(4) of this section.

(2) A batch of biogas-derived renewable fuel must comply with the requirements specified in § 80.1426(d).

(3) The RNG producer, RNG importer, or biogas closed distribution system RIN generator must assign a number (the ''batch number'') to each batch of RNG or biogas-derived renewable fuel consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the calendar year in which the batch was produced, and a unique number for the batch, beginning with the number one for the first batch produced each calendar year and each subsequent batch during the calendar year being assigned the next sequential number (*e.g.,* 4321–54321–23–000001, 4321–54321–23–000002, etc.).

(4) The batch volume of RNG must be calculated as follows:

$$V_{RNG,p} = V_{NG} * \frac{V_{BG,p}}{V_{BG,total}} * R$$

Where:

$V_{RNG,p}$ = The batch volume of RNG for batch pathway p, in Btu LHV.

$V_{NG}$ = The total volume of natural gas produced at the RNG production facility for the calendar month, in Btu LHV, as measured under § 80.155.

$V_{BG,p}$ = The total volume of biogas used to produce RNG under batch pathway p for the calendar month, in Btu HHV, per § 80.105(j).

$V_{BG,total}$ = The total volume of biogas used to produce RNG under all batch pathways for the calendar month, in Btu HHV, per § 80.105(j).

R = The renewable fraction of the natural gas produced at the RNG production facility for the calendar month. For natural gas produced only from renewable feedstocks, R is equal to 1. For natural gas produced from both renewable and non-renewable feedstocks, R must be measured by a carbon-14 dating test method, per § 80.1426(f)(9).

**§ 80.115 RNG RIN separators.**

(a) *General requirements.* (1) Any RNG RIN separator must comply with the requirements of this section.

(2) The RNG RIN separator must also comply with all other applicable requirements of this part and 40 CFR part 1090.

(3) If the RNG RIN separator meets the definition of more than one type of regulated party under this part or 40 CFR 1090, the RNG RIN separator must comply with the requirements applicable to each of those types of regulated parties.

(4) The RNG RIN separator must comply with all applicable requirements of this part, regardless of whether the requirements are identified in this section.

(b) *Registration.* (1) The RNG RIN separator must register with EPA under §§ 80.135, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(2) A dispensing location may only be included in one RNG RIN separator's registration at a time.

(c) *Reporting.* The RNG RIN separator must submit reports to EPA under §§ 80.140, 80.1451, and 80.1452, as applicable.

(d) *Recordkeeping.* The RNG RIN separator must create and maintain records under §§ 80.145 and 80.1454.

(e) *PTDs.* On each occasion when the RNG RIN separator transfers title of renewable fuel and RINs to another party, the transferor must provide to the transferee PTDs under § 80.1453.

(f) *Measurement.* (1) All measurements must be done in accordance with § 80.155.

(2) An RNG RIN separator must measure the volume of natural gas, in Btu LHV, withdrawn from the natural gas commercial pipeline system.

(g) *Attest engagements.* The RNG RIN separator must submit annual attest engagement reports to EPA under §§ 80.165 and 80.1464 using procedures specified in 40 CFR 1090.1800 and 1090.1805.

**§ 80.120 Parties that use biogas as a biointermediate or RNG as a feedstock or as process heat or energy.**

(a) *General requirements.* (1) Any renewable fuel producer that uses biogas as a biointermediate or RNG as a feedstock or as process heat or energy under § 80.1426(f)(12) or (13) must comply with the requirements of this section.

(2) The renewable fuel producer must also comply with all other applicable requirements of this part and 40 CFR part 1090.

(3) If the renewable fuel producer meets the definition of more than one type of regulated party under this part or 40 CFR 1090, the renewable fuel producer must comply with the requirements applicable to each of those types of regulated parties.

(4) The renewable fuel producer must comply with all applicable requirements of this part, regardless of whether they are identified in this section.

(5) The transfer and batch segregation limits specified in § 80.1476(g) do not apply.

(b) *Registration.* The renewable fuel producer must register with EPA under §§ 80.135, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The renewable fuel producer must submit reports to EPA under §§ 80.140, 80.1451, and 80.1452, as applicable.

(d) *Recordkeeping.* The renewable fuel producer must create and maintain records under §§ 80.145 and 80.1454.

(e) *PTDs.* On each occasion when the renewable fuel producer transfers title of biogas-derived renewable fuel and RINs to another party, the transferor must provide to the transferee PTDs under §§ 80.150 and 80.1453.

(f) *Measurement.* (1) All measurements must be done in accordance with § 80.155.

(2) A renewable fuel producer must measure the volume of natural gas, in Btu LHV, withdrawn from the natural gas commercial pipeline system.

(g) *Attest engagements.* The renewable fuel producer must submit annual attest engagement reports to EPA under §§ 80.165 and 80.1464 using procedures specified in 40 CFR 1090.1800 and 1090.1805.

(h) *QAP.* Prior to the generation of a Q–RIN for biogas-derived renewable fuel produced from biogas used as a biointermediate or RNG used as a feedstock, the renewable fuel producer must meet all applicable requirements specified in § 80.170.

**§ 80.125 RINs for RNG.**

(a) *General requirements.* (1) Any party that generates, assigns, transfers, receives, separates, or retires RINs for RNG must comply with the requirements of this section.

(2) Any party that transacts RINs for RNG under this section must transact the RINs as specified in § 80.1452.

(b) *RIN generation.* (1) Only RNG producers may generate RINs for RNG injected into a natural gas commercial pipeline system.

(2) RNG producers must generate RINs for only the biomethane content of biogas supplied by a biogas producer registered under § 80.135.

(3) RNG producers must generate RINs using the applicable requirements for RIN generation in § 80.1426.

(4) If non-renewable components are blended into RNG, the RNG producer must generate RINs for only the biomethane content of the RNG prior to blending.

(5) RNG producers must use the measurement procedures specified in § 80.155 to determine the heating value of RNG for the generation of RINs.

(6) The number of RINs generated for a batch volume of RNG under each batch pathway must be calculated as follows:

$$RIN_{RNG,p} = \frac{V_{RNG,p}}{EqV_{RNG}}$$

Where:

$RIN_{RNG,p}$ = The number of RINs generated for a batch of RNG under batch pathway p, in gallon-RINs.

$V_{RNG,p}$ = The batch volume of RNG for batch pathway p, in Btu LHV, per § 80.110(j)(4).

$EqV_{RNG}$ = The equivalence value for RNG, in Btu LHV per RIN, per § 80.1415(b)(5).

(7) When RNG is injected from multiple RNG production facilities at a pipeline interconnect, the total number of RINs generated must not be greater than the total number of RINs eligible to be generated under § 80.1415(b)(5) for the total volume of RNG injected by all RNG production facilities at that pipeline interconnect.

(8) For RNG that is trucked prior to injection into a natural gas commercial pipeline system, the total volume of RNG injected for the calendar month, in Btu LHV, must not be greater than the lesser of the total loading or unloading volume measurement for the month, in Btu LHV, as required under § 80.110(f)(2)(ii).

(9) Renewable fuel producers that retire RINs for RNG used as a feedstock under paragraph (e) of this section may only generate RINs for the renewable fuel produced from RNG if all applicable requirements under this part are met.

(c) *RIN assignment and transfer.* (1) RNG producers must assign the RINs generated for a batch of RNG to the specific volume of RNG injected into the natural gas commercial pipeline system.

(2) Except as specified in paragraph (c)(1) of this section, no party may assign a RIN to a volume of RNG.

(3) Each party that transfers title of a volume of RNG to another party must

transfer title of any assigned RINs for the volume of RNG to the transferee.

(d) *RIN separation.* (1) Only the following parties may separate a RIN from RNG:

(i) The party that withdrew the RNG from the natural gas commercial pipeline system.

(ii) The party that produced or oversaw the production of the renewable CNG/LNG from the RNG.

(iii) The party that used or dispensed for use the renewable CNG/LNG as transportation fuel.

(2) An RNG RIN separator must only separate a RIN from RNG if all the following requirements are met:

(i) The RNG used to produce the renewable CNG/LNG was measured using the procedures specified in § 80.155.

(ii) The RNG RIN separator has the following documentation demonstrating that the volume of renewable CNG/LNG was used as transportation fuel:

(A) If the RNG RIN separator sold or used the renewable CNG/LNG, records demonstrating the date, location, and volume of renewable CNG/LNG sold or used as transportation fuel.

(B) If the RNG RIN separator is relying on documentation from another party, all the following as applicable:

(*1*) A written contract with the other party for the sale or use of the renewable CNG/LNG as transportation fuel.

(*2*) Records from the other party demonstrating the date, location, and volume of renewable CNG/LNG sold or used as transportation fuel.

(*3*) An affidavit from each other party confirming all the following:

(*i*) That the volume of renewable CNG/LNG was used as transportation fuel and for no other purpose.

(*ii*) That the party will not separate RINs for this volume of RNG.

(*iii*) That the party has not provided affidavits to any other party for the purpose of complying with the requirements of this paragraph (d)(2)(ii).

(iii) The volume of RNG was only used to produce renewable CNG/LNG that is used as transportation fuel and for no other purpose.

(iv) No other party used the measurement information under paragraph (d)(2)(i) of this section or the information required under paragraph (d)(2)(ii) of this section to separate RINs for the RNG.

(v) No other party has separated RINs for the RNG using the same dispensing location during the calendar month.

(vi) The RNG RIN separator follows the applicable provisions under § 80.1429(a), (b)(10), and (c) through (e).

(3) An obligated party must not separate RINs for RNG under § 80.1429(b)(1) unless the obligated party meets the requirements in paragraph (d)(1) of this section.

(4) A party must only separate a number of RINs equal to the total volume of RNG (where the Btu LHV are converted to gallon-RINs using the conversion specified in § 80.1415(b)(5)) that the party demonstrates is used as renewable CNG/LNG under paragraph (d)(2) of this section.

(e) *RIN retirement.* (1) A party must retire RINs generated for RNG if any of the conditions specified in § 80.1434(a) apply and must comply with § 80.1434(b).

(2)(i) A party must retire all assigned RINs for a volume of RNG if the RINs are not separated under paragraph (d) of this section by the date the assigned RINs expire under § 80.1428(c).

(ii) A party must retire any expired RINs under paragraph (e)(2)(i) of this section by March 31 of the subsequent year. For example, if an RNG producer assigns RINs for RNG in 2025, the RINs expire if they are not separated under paragraph (d) of this section by December 31, 2026, and must be retired by March 31, 2027.

(3) A party that uses RNG for a purpose other than to produce renewable CNG/LNG (*e.g.,* as a feedstock, as process heat under § 80.1426(f)(12), or as process energy under § 80.1426(f)(13)) must retire any assigned RINs for the volume of RNG within 5 business days of such use of the RNG.

**§ 80.130 RINs for renewable CNG/LNG from a biogas closed distribution system.**

(a) *General requirements.* (1) Any party that generates, assigns, separates, or retires RINs for renewable CNG/LNG from a biogas closed distribution system must comply with the requirements of this section.

(2) Parties must report all RIN transactions to EMTS as specified in § 80.1452.

(b) *RIN generation.* (1) Biogas closed distribution system RIN generators must generate RINs using the applicable requirements for RIN generation in under this part.

(2) RINs for renewable CNG/LNG from a biogas closed distribution system may be generated if all the following requirements are met:

(i) The renewable CNG/LNG is produced from renewable biomass and qualifies to generate RINs under an approved pathway.

(ii) The biogas closed distribution system RIN generator has entered into a written contract for the sale or use of a specific quantity of renewable CNG/LNG for use as transportation fuel, and has obtained affidavits from all parties selling or using the renewable CNG/LNG certifying that the renewable CNG/LNG was used as transportation fuel.

(iii) The renewable CNG/LNG is used as transportation fuel and for no other purpose.

(c) *RIN separation.* A biogas closed distribution system RIN generator must separate RINs generated for renewable CNG/LNG under § 80.1429(b)(5)(ii).

(d) *RIN retirement.* A party must retire RINs generated for renewable CNG/LNG from a biogas closed distribution if any of the conditions specified in § 80.1434(a) apply and must comply with § 80.1434(b).

**§ 80.135 Registration.**

(a) *Applicability.* The following parties must register using the procedures specified in this section, § 80.1450 and 40 CFR 1090.800:

(1) Biogas producers.

(2) RNG producers.

(3) RNG importers.

(4) Biogas closed distribution system RIN generators.

(5) RNG RIN separators.

(6) Renewable fuel producers using biogas as a biointermediate or RNG as a feedstock.

(b) *General registration requirements.* Parties must submit applicable information for companies and facilities as specified in 40 CFR 1090.805.

(1) *New registrants.* (i) Parties required to register under this subpart must have an EPA-accepted registration prior to engaging in regulated activities under this subpart.

(ii) Registration information must be submitted at least 60 days prior to engaging in regulated activities under this subpart.

(iii) Parties may engage in regulated activities under this subpart once EPA has accepted their registration and they have met all other applicable requirements under this subpart.

(2) *Existing renewable CNG/LNG registrations.* (i) Parties listed in paragraph (a) of this section must submit updated registration information that complies with the applicable requirements of this section for any company or facility covered by a registration accepted under § 80.1450(b) for the generation of RINs under § 80.1426(f)(10)(ii) or (11)(ii) no later than October 1, 2024.

(ii) A biogas closed distribution system RIN generator or biogas producer does not need to submit an updated engineering review for any facility in the biogas closed distribution system as specified in § 80.1450(d)(1) before the next three-year engineering review update is due as specified in § 80.1450(d)(3).

(3) *Engineering reviews.* (i) Any party required to register a facility under this section must undergo all the following:

(A) A third-party engineering review as specified in § 80.1450(b)(2).

(B) Three-year engineering review updates as specified in § 80.1450(d)(3).

(ii) Third-party engineering reviews and three-year engineering review updates required under paragraph (b)(3)(i) of this section must evaluate all applicable registration information submitted under this section as well as all applicable requirements in § 80.1450(b).

(iii) A party may arrange for an independent third-party engineer to conduct a single site visit and submit a single engineering review report for a facility that performs multiple activities (*e.g.,* a facility that both produces biogas and upgrades it to RNG) under this subpart as long as the site visit and engineering review report includes all the requirements for each activity performed.

(4) *Registration updates.* (i) Parties registered under this section must submit updated registration information to EPA within 30 days when any of the following occur:

(A) The registration information previously supplied becomes incomplete or inaccurate.

(B) Facility information is updated under § 80.1450(d)(1), as applicable.

(C) A change of ownership is submitted under 40 CFR 1090.820.

(ii) Parties registered under this section must submit updated registration information to EPA within 7 days when any facility information is updated under § 80.1450(d)(2).

(iii) Parties that register a facility under this section must update their registration information and undergo a three-year engineering review update as specified in § 80.1450(d)(3).

(5) *Registration deactivations.* EPA may deactivate the registration of a party registered under this section as specified in § 80.1450(h), 40 CFR 1090.810, or 40 CFR 1090.815, as applicable.

(c) *Biogas producer.* In addition to the information required under paragraph (b) of this section, a biogas producer must submit all the following information for each biogas production facility:

(1) Information describing the biogas production capacity for the biogas production facility, in Btu HHV, including the following:

(i) Information regarding the permitted capacity in the most recent applicable air permits issued by EPA, a state, a local air pollution control agency, or a foreign governmental agency that governs the biogas production facility, if available.

(ii) Documents demonstrating the biogas production facility's nameplate capacity.

(iii) Information describing the biogas production facility's biogas production for each of the last three calendar years prior to the registration submission, if available.

(2) Whether the biogas will be used to produce RNG, renewable CNG/LNG, or biointermediate and information identifying the facility that will be supplied.

(3) The following information related to biogas measurement:

(i) A description of how biogas will be measured under § 80.155(a), including the specific standards under which the meters are operated.

(ii) A description of the biogas production process, including a process flow diagram that includes metering type(s) and location(s).

(iii) For an alternative measurement protocol under § 80.155(a)(3), all the following:

(A) A description of why the biogas producer is unable to use meters that comply with the requirements specified in § 80.155(a)(1) and (2), as applicable.

(B) A description of how measurement is conducted.

(C) Any standards or specifications that apply.

(D) A description of all routine maintenance and the frequency that such maintenance will be conducted.

(E) A description of the frequency of all measurements and how often such measurements will be recorded under the alternative measurement protocol.

(F) A comparison between the accuracy, precision, and reliability of the alternative measurement protocol and the requirements specified in § 80.155(a)(1) and (2), as applicable, including any supporting data.

(4) For biogas used to produce renewable CNG/LNG in a biogas closed distribution system, all the following additional information:

(i) A process flow diagram of each step of the physical process from feedstock entry to the point where the renewable CNG/LNG is dispensed as transportation fuel. This includes all the following:

(A) Feedstock processing.

(B) Biogas production.

(C) Biogas processing.

(D) Renewable CNG/LNG production.

(E) Points where non-renewable natural gas may be added.

(F) Dispensing stations.

(G) Measurement locations and equipment.

(H) Major equipment (*e.g.,* tanks, pipelines, flares, separation equipment, compressors, and dispensing infrastructure).

(I) Any other process-related information as requested by EPA.

(ii) 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.

(iii) A description of the physical process from biogas production to dispensing of renewable CNG/LNG as transportation fuel, including the biogas closed distribution system.

(iv) A description of the vehicle fleet and dispensing stations that are expected to use and distribute the renewable CNG/LNG as transportation fuel.

(5) For biogas used as a biointermediate, all the information specified in § 80.1450(b)(1)(ii)(B).

(6) For biogas used to produce RNG, all the following additional information:

(i) The RNG producer that will upgrade the biogas.

(ii) A process flow diagram of the physical process from biogas production to entering the RNG production facility, including major equipment (*e.g.,* tanks, pipelines, flares, separation equipment).

(iii) A description of the physical process from biogas production to entering the RNG production facility, including an explanation of how the biogas reaches the RNG production facility.

(7) For biogas produced in an agricultural digester, all the following information:

(i) A separated yard waste plan specified in § 80.1450(b)(1)(vii)(A), as applicable.

(ii) Crop residue information specified in § 80.1450(b)(1)(xv), as applicable.

(iii) A process flow diagram of the physical process from feedstock entry to biogas production, including major equipment (*e.g.,* feedstock preprocessing equipment, tanks, digesters, pipelines, flares).

(8) For biogas produced in a municipal wastewater treatment facility digester, a process flow diagram of the physical process from feedstock entry to biogas production, including major equipment (*e.g.,* feedstock preprocessing equipment, tanks, digesters, pipelines, flares).

(9) For biogas produced in a separated MSW digester, all the following information:

(i) Separated MSW plan specified in § 80.1450(b)(1)(viii).

(ii) A process flow diagram of the physical process from feedstock entry to biogas production, including major equipment (*e.g.,* feedstock preprocessing equipment, tanks, digesters, pipelines, flares).

(10) For biogas produced in other waste digesters, all the following information, as applicable:

(i) A separated MSW plan specified in § 80.1450(b)(1)(viii).

(ii) A separated yard waste plan specified in § 80.1450(b)(1)(vii)(A).

(iii) Crop residues information specified in § 80.1450(b)(1)(xv).

(iv) A separated food waste plan or biogenic waste oils/fats/greases plan specified in § 80.1450(b)(1)(vii)(B).

(v) A process flow diagram of each step of the physical process from feedstock entry to the point where the biogas either leaves the facility or is used to produce RNG, biointermediate, or biogas-derived renewable fuel. This includes all the following:

(A) Feedstock processing.

(B) Biogas production.

(C) Biogas processing.

(D) Major equipment (*e.g.,* feedstock preprocessing equipment, tanks, digesters, pipelines, flares).

(E) Measurement locations and equipment.

(F) Any other process-related information as requested by EPA.

(vi) For biogas produced in a mixed digester, all the following:

(A) For biogas producers using a value under § 80.105(j)(2)(iv)(E), all the following:

(*1*) The cellulosic converted fraction (CF) for each cellulosic biogas feedstock that will be used in § 80.105(j)(2)(iii), in Btu HHV/lb feedstock, rounded to the nearest whole number.

(*2*) Data supporting the cellulosic CF from each cellulosic biogas feedstock. Data must be derived from processing of cellulosic biogas feedstock(s) in anaerobic digesters without simultaneous conversion under similar conditions as will be run in the simultaneously converted process. Data must be either from the facility when it was processing solely the feedstock that does have a minimum 75% adjusted cellulosic content or from a representative sample of other representative facilities processing the feedstock that does have a minimum 75% adjusted cellulosic content.

(*3*) A description of how the cellulosic CF was determined, including any calculations demonstrating how the data were used.

(*4*) A list of ranges of processing conditions, including temperature, solids mean residence time, and hydraulic mean residence time, for which the cellulosic CF is accurate and a description of how such processing conditions will be measured by the facility.

(*5*) A demonstration that no biogas generated from non-cellulosic biogas feedstocks could be used to generate RINs for a batch of renewable fuel with a D code of 3 or 7. EPA may reject this demonstration if it is not sufficiently protective.

(B) A description of the meters used to determine the mass of cellulosic biogas feedstock.

(C) The location of feedstock sampling, additive (*e.g.,* water) addition, and mass measurement for use in § 80.105(j)(2)(iii) included in the process flow diagram required under paragraph (c)(10)(v) of this section.

(D) For facilities using composite sampling under § 80.155(c)(3), a composite sampling plan, including all the following:

(*1*) A description of when and where the samples will be collected.

(*2*) A description of how the samples will be stored prior to testing.

(*3*) A description of how daily representative samples will be mixed, including how the ratio of each sample will be determined.

(*4*) A description of how often testing will occur.

(*5*) A description of how the plan complies with § 80.155(c)(2).

(d) *RNG producer.* In addition to the information required under paragraph (b) of this section, an RNG producer must submit all the following information for each RNG production facility:

(1) All applicable information in § 80.1450(b)(1)(ii).

(2) Information to establish the RNG production capacity for the RNG production facility, in Btu LHV, including all the following, as applicable:

(i) Information regarding the permitted capacity in the most recent applicable air permits issued by EPA, a state, a local air pollution control agency, or a foreign governmental agency that governs the RNG production facility, if available.

(ii) Documents demonstrating the RNG production facility's nameplate capacity.

(iii) Information describing the RNG production facility's RNG production for each of the last three calendar years prior to the registration submission, if available.

(3) The following information related to RNG measurement:

(i) A description of how RNG will be measured under § 80.155(a), including the specific standards under which the meters are operated.

(ii) A description of the RNG production process, including a process flow diagram that includes metering type(s) and location(s).

(iii) For an alternative measurement protocol under § 80.155(a)(3), all the following:

(A) A description of why the RNG producer is unable to use meters that comply with the requirements specified in § 80.155(a)(1) and (2), as applicable.

(B) A description of how measurement is conducted.

(C) Any standards or specifications that apply.

(D) A description of all routine maintenance and the frequency that such maintenance will be conducted.

(E) A description of the frequency of all measurements and how often such measurements will be recorded under the alternative measurement protocol.

(F) A comparison between the accuracy, precision, and reliability of the alternative measurement protocol and the requirements specified in § 80.155(a)(1) and (2), as applicable, including any supporting data.

(4) The natural gas commercial pipeline system name and pipeline interconnect location into which the RNG will be injected.

(5) A description of the natural gas specifications for the natural gas commercial pipeline system into which the RNG will be injected, including information on all parameters regulated by the pipeline (*e.g.,* hydrogen sulfide, total sulfur, carbon dioxide, oxygen, nitrogen, heating content, moisture, siloxanes, and any other available data related to the gas components).

(6) For three-year registration updates, information related to RNG quality, including all the following:

(i) A certificate of analysis—including the major and minor gas components—from an independent laboratory for a representative sample of the biogas produced at the biogas production facility as specified in § 80.155(b).

(ii) A certificate of analysis—including the major and minor gas components—from an independent laboratory for a representative sample of the RNG prior to addition of non-renewable components as specified in § 80.155(b).

(iii) If the RNG is blended with non-renewable components prior to injection into a natural gas commercial pipeline system, a certificate of analysis from an independent laboratory for a representative sample of the RNG after blending with non-renewable components as specified in § 80.155(b).

(iv) A summary table with the results of the certificates of analysis required under paragraphs (d)(6)(i) through (iii) of this section and the natural gas specifications required under paragraph (d)(5) of this section converted to the same units.

(v) EPA may approve an RNG producer's request of an alternative analysis in lieu of the certificates of analysis and summary table required under paragraphs (d)(6)(i) through (iv) of this section if the RNG producer demonstrates that the alternative analysis provides information that is equivalent to that provided in the certificates of analysis and that the RNG will meet all natural gas specifications required under paragraph (d)(5) of this section.

(7) A RIN generation protocol that includes all the following information:

(i) The procedure for allocating RNG injected into the natural gas commercial pipeline system to each RNG production facility and each biogas production facility, including how discrepancies in meter values will be handled.

(ii) A diagram showing the locations of flow meters, gas analyzers, and in-line GC meters used in the allocation procedure.

(iii) A description of when RINs will be generated (*e.g.,* receipt of monthly pipeline statement, etc).

(8) For an RNG production facility that injects RNG at a pipeline interconnect that also has RNG injected from other sources, a description of how the RNG producers will allocate RINs to ensure that all facilities comply with the requirements specified in § 80.125(b)(7).

(9) For a foreign RNG producer, all the following additional information:

(i) The applicable information specified in § 80.160.

(ii) Whether the foreign RNG producer will generate RINs for their RNG.

(iii) For non-RIN generating foreign RNG producers, the name and EPA-issued company and facility IDs of the contracted importer under § 80.160(e).

(e) *RNG importer.* In addition to the information required under paragraph (b) of this section, an RNG importer must submit all the following information:

(1) The name and EPA-issued company and facility IDs of the contracted non-RIN generating foreign RNG producer under § 80.160(e).

(2) The name and contact information for the independent third party specified in § 80.160(h).

(f) *RNG RIN separator.* In addition to the information required under paragraph (b) of this section, an RNG RIN separator must submit a list of locations of any dispensing stations where the RNG RIN separator supplies or intends to supply renewable CNG/LNG for use as transportation fuel.

(g) *Renewable fuel producer using biogas as a biointermediate.* In addition to the information required under paragraph (b) of this section, a renewable fuel producer using biogas as a biointermediate must submit all the following:

(1) All applicable information in § 80.1450(b).

(2) Documentation demonstrating a direct connection between the biogas production facility and the renewable fuel production facility.

**§ 80.140 Reporting.**

(a) *General provisions*—(1) *Applicability.* Parties must submit reports to EPA according to the schedule and containing all applicable information specified in this section.

(2) *Forms and procedures for report submission.* All reports required under this section must be submitted using forms and procedures specified by EPA.

(3) *Additional reporting elements.* In addition to any applicable reporting requirement under this section, parties must submit any additional information EPA requires to administer the reporting requirements of this section.

(4) *English language reports.* All reported information submitted to EPA under this section must be submitted in English, or must include an English translation.

(5) *Signature of reports.* Reports required under this section must be signed and certified as meeting all the applicable requirements of this subpart by the RCO or their delegate identified in the company registration under 40 CFR 1090.805(a)(1)(iv).

(6) *Report submission deadlines.* Reports required under this section must be submitted by the following deadlines:

(i) Monthly reports must be submitted by the applicable monthly deadline in § 80.1451(f)(4).

(ii) Quarterly reports must be submitted by the applicable quarterly deadline in § 80.1451(f)(2).

(iii) Annual reports must be submitted by the applicable annual deadline in § 80.1451(f)(1).

(8) *Volume standardization.* (i) All volumes reported to EPA in scf under this section must be standardized to STP.

(ii) All volumes reported to EPA in Btu under this section must be converted according to § 80.155(f), if applicable.

(iii) All other volumes reported to EPA under this section must be standardized according to § 80.1426(f)(8).

(b) *Biogas producers.* A biogas producer must submit monthly reports to EPA containing all the following information for each batch of biogas:

(1) Batch number.

(2) Production date (end date of the calendar month).

(3) Verification status of the batch.

(4) The batch volume of biogas supplied to the downstream party, in Btu HHV and scf, as measured under § 80.155.

(5) The associated pathway information, including D code, designated use of the biogas (*e.g.,* biointermediate, renewable CNG/LNG, or RNG), and feedstock information.

(6) The EPA-issued company and facility IDs for the RNG producer, biogas closed distribution system RIN generator, or renewable fuel producer that received the batch of the biogas.

(c) *RNG producers.* (1) An RNG producer must submit quarterly reports to EPA containing all the following information:

(i) The total volume of RNG, in Btu LHV and scf, produced and injected into the natural gas commercial pipeline system as measured under § 80.155.

(ii) The total volume of non-renewable components, in Btu LHV, added to RNG prior to injection into the natural gas commercial pipeline system.

(2) A non-RIN generating foreign RNG producer must submit monthly reports to EPA containing all the following information for each batch of RNG:

(i) Batch number.

(ii) Production date (end date of the calendar month).

(iii) Verification status of the batch.

(iv) The associated pathway information, including D code, production process, and feedstock information.

(v) The EPA-issued company and facility IDs for the RNG importer that will generate RINs for the batch.

(d) *Biogas closed distribution system RIN generators.* A biogas closed distribution system RIN generator must submit monthly reports to EPA containing all the following information:

(1)(i) For fuels that are gaseous at STP, the type and volume of biogas-derived renewable fuel, in Btu LHV.

(ii) For all other fuels, the type and volume of biogas-derived renewable fuel, in gallons.

(2) Each of the following, as applicable, as measured under § 80.155:

(i) The volume of biogas, in Btu HHV, used to produce the treated biogas that is used to produce the biogas-derived renewable fuel.

(ii) The volume of biogas, in Btu HHV, used to produce the biogas-derived renewable fuel.

(iii) The volume of treated biogas, in Btu HHV, used to produce the biogas-derived renewable fuel.

(3) The name(s) and location(s) of where the biogas-derived renewable fuel is used or sold for use as transportation fuel.

(4)(i) For fuels that are gaseous at STP, the volume of biogas-derived renewable fuel, in Btu LHV, used at each location where the biogas-derived renewable fuel is used or sold for use as transportation fuel.

(ii) For all other fuels, the volume of biogas-derived renewable fuel, in gallons, used at each location where the biogas-derived renewable fuel is used or sold for use as transportation fuel.

(5) All applicable information in § 80.1451(b).

(e) *RNG RIN separators.* (1) An RNG RIN separator must submit quarterly reports to EPA containing all the following information:

(i) Name and location of each point where RNG was withdrawn from the natural gas commercial pipeline system.

(ii) Volume of RNG, in Btu LHV, withdrawn from the natural gas commercial pipeline system during the reporting period by withdrawal location.

(iii) Volume of renewable CNG/LNG, in Btu LHV, dispensed during the reporting period by withdrawal location.

(2) An RNG RIN separator must submit monthly reports to EPA containing all the following information for each batch of biogas:

(i) The location where renewable CNG/LNG was dispensed as transportation fuel.

(ii) The volume of renewable CNG/LNG, in Btu LHV, dispensed as transportation fuel at the location.

(f) *Retirement of RINs for RNG used as a feedstock or process heat.* A party that retires RINs for RNG used as a feedstock or as process heat or energy under § 80.1426(f)(12) or (13) must submit quarterly reports to EPA containing all the following information:

(1) The name(s) and location(s) of the natural gas commercial pipeline where the RNG was withdrawn.

(2) Volume of RNG, in Btu LHV, withdrawn from the natural gas commercial pipeline during the reporting period by location.

(3) The EPA-issued company and facility IDs for the facility that used the withdrawn RNG as a feedstock or as process heat.

(4) For each facility, the following information, as applicable:

(i) For fuels that are gaseous at STP, the volume of biogas-derived renewable fuel, in Btu LHV, produced using the withdrawn RNG.

(ii) For all other fuels, the volume of biogas-derived renewable fuel, in gallons, produced using the withdrawn RNG.

(5) The number of RINs for RNG retired during the reporting period by D code and verification status.

**§ 80.145 Recordkeeping.**

(a) *General requirements*—(1) *Records to be kept.* All parties subject to the requirements of this subpart must keep the following records:

(i) *Compliance report records.* Records related to compliance reports submitted to EPA under this part as follows:

(A) Copies of all reports submitted to EPA.

(B) Copies of any confirmation received from the submission of such reports to EPA.

(C) Copies of all underlying information and documentation used to prepare and submit the reports.

(D) Copies of all calculations required under this subpart.

(ii) *Registration records.* Records related to registration under this part and 40 CFR part 1090, subpart I, as follows:

(A) Copies of all registration information and documentation submitted to EPA.

(B) Copies of all underlying information and documentation used to prepare and submit the registration request.

(iii) *PTD records.* Copies of all PTDs required under this part.

(iv) *Subpart M records.* Any applicable record required under 40 CFR part 80, subpart M.

(v) *QAP records.* Information and documentation related to participation in any QAP program, including contracts between the entity and the QAP provider, records related to verification activities under the QAP, and copies of any QAP-related submissions.

(vi) *Sampling, testing, and measurement records.* Documents supporting the sampling, storage, testing, and measurement results relied upon under § 80.155, including all results, maintenance records, and calibration records.

(vii) *Other records.* Any other records relied upon by the party to demonstrate compliance with this subpart.

(viii) *Potentially invalid RINs.* Any records and copies of notifications related to potentially inaccurate or non-qualifying biogas volumes or potentially invalid RINs under § 80.185.

(ix) *RNG importers and foreign parties.* Any records related to RNG importers and foreign parties under §§ 80.160, 80.1466, and 80.1467, as applicable.

(2) *Length of time records must be kept.* The records required under this subpart must be kept for five years from the date they were created, except that records related to transactions involving RINs must be kept for five years from the date of the RIN transaction.

(3) *Make records available to EPA.* Any party required to keep records under this section must make records available to EPA upon request by EPA. For records that are electronically generated or maintained, the party must make available any equipment and software necessary to read the records or, upon approval by EPA, convert the electronic records to paper documents.

(4) *English language records.* Any record requested by EPA under this section must be submitted in English, or include an English translation.

(b) *Biogas producers.* In addition to the records required under paragraph (a) of this section, a biogas producer must keep all the following records:

(1) Copies of all contracts, PTDs, affidavits required under this part, and all other commercial documents with any RNG producer, biointermediate producer, or renewable fuel producer.

(2) Documents supporting the volume of biogas, in Btu HHV and scf, produced for each batch.

(3) Documents supporting the composition and cleanup of biogas produced for each batch (*e.g.,* meter readings of composition, records of adsorbent replacement, records showing equipment operation including maintenance and energy usage, and records of component streams separated from the biomethane-enriched stream).

(4) Information and documentation related to participation in any QAP program, including contracts between the biogas producer and the QAP provider, records related to verification activities under the QAP, and copies of any QAP-related submissions.

(5) Records related to measurement, including types of equipment used, metering process, maintenance and calibration records, documents supporting adjustments related to error correction, and measurement data.

(6) Documents supporting the use of each process heat source and supporting the amount of each source used in the production process for each batch.

(7) All the applicable recordkeeping requirements for digester feedstocks under § 80.1454.

(8) The following information and documents showing that the biogas came from renewable biomass:

(i) For all anaerobic digesters, documentation showing the mass of each feedstock type input into the digester for each batch of biogas.

(ii) For agricultural digesters, a quarterly affidavit signed by the RCO or their delegate that only animal manure, crop residue, or separated yard waste that had an adjusted cellulosic content of at least 75% were used to produce biogas during the quarter.

(iii) For municipal wastewater treatment facility digesters and separated MSW digesters, a quarterly affidavit signed by the RCO or their delegate that only feedstocks that had an adjusted cellulosic content of at least 75% were used to produce biogas during the quarter.

(iv) For biogas produced from separated yard waste, separated food waste, or biogenic waste oils/fats/greases, documents required under § 80.1454(j)(1).

(v) For biogas produced from separated MSW, documents required under § 80.1454(j)(2).

(9) For biogas produced in a mixed digester, all the following:

(i) Documents for each delivery of feedstock to the biogas production facility, demonstrating all the following for each unique combination of feedstock supplier and type of feedstock:

(A) The name of the feedstock supplier.

(B) The type of feedstock.

(C) The mass of that feedstock delivered from that supplier.

(ii) Data, documents, and calculations related to digester operating conditions required under § 80.105(f)(2)(iii)(D).

(iii) Documents for each batch showing how measurement data for volatile solids, total solids, and mass were used to calculate batch volume under § 80.105(j)(2).

(iv) Documents showing the amounts of additives (*e.g.,* water), timing of additive addition, and location of additive addition for all additives added to the feedstock.

(v) For samples tested for volatile solids and total solids, documents showing the time and location that each sample was obtained and tested.

(c) *RNG producers.* In addition to the records required under paragraph (a) of this section, an RNG producer must keep all the following records:

(1) Records related to the generation and assignment of RINs, including all the following information:

(i) Batch volume.

(ii) Batch number.

(iii) Production date when RINs were assigned to RNG.

(iv) Injection point into the natural gas commercial pipeline system.

(v) Volume of biogas, in Btu HHV and scf, respectively, received at each RNG production facility.

(vi) Volume of RNG, in Btu LHV, Btu HHV, and scf, produced at each RNG production facility.

(vii) Pipeline injection statements describing the energy and volume of natural gas for each pipeline interconnect.

(2) Records related to each RIN transaction, separately for each transaction, including all the following information:

(i) A list of the RINs generated, owned, purchased, sold, separated, retired, or reinstated.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RINs.

(iv) Additional information related to details of the transaction and its terms.

(3) Documentation recording the transfer and sale of RNG, from the point of biogas production to the facility that sells or uses the fuel for transportation purposes.

(4) A copy of the RNG producer's Compliance Certification required under Title V of the Clean Air Act.

(5) Results of any laboratory analysis of chemical composition or physical properties.

(6) Documents supporting the composition of biogas and RNG and cleanup of biogas for each batch (*e.g.,* meter readings of composition, records of adsorbent replacement, records showing equipment operation including maintenance and energy usage, and records of component streams separated from the biomethane-enriched stream).

(7) Documents supporting the use of each process heat source and supporting the amount of each source used in the production process for each batch.

(8) Records related to measurement, including types of equipment used, metering process, maintenance and calibration records, documents supporting adjustments related to error correction, and measurement data.

(9) Information and documentation related to participation in any QAP program, including contracts between the RNG producer and the QAP provider, records related to verification activities under the QAP, and copies of any QAP-related submissions.

(10) For an RNG production facility that injects RNG at a pipeline interconnect that also has RNG injected from other sources, documents showing that RINs generated for the facility comply with the requirements specified in § 80.125(b)(7).

(11) Documentation of any waiver provided by the natural gas commercial pipeline system for any parameter of the RNG that does not meet the natural gas specifications submitted under § 80.135(d)(5).

(d) *Biogas closed distribution system RIN generators.* In addition to the records required under paragraph (a) of this section, a biogas closed distribution system RIN generator must keep all the following records:

(1) Documentation demonstrating that the renewable CNG/LNG was produced from renewable biomass and qualifies to generate RINs under an approved pathway.

(2) Copies of any written contract for the sale or use of renewable CNG/LNG as transportation fuel, and copies of any affidavit from a party that sold or used the renewable CNG/LNG as transportation fuel.

(e) *RNG RIN separators.* In addition to the records required under paragraph (a) of this section, an RNG RIN separator must keep all the following records:

(1) Documentation indicating the volume of RNG, in Btu LHV, withdrawn from each interconnect of the natural gas commercial pipeline system.

(2) Documentation demonstrating the volume of RNG, in Btu LHV, withdrawn from the natural gas commercial pipeline system that was used to produce renewable CNG/LNG.

(3) Documentation indicating the volume of renewable CNG/LNG, in Btu LHV, dispensed as transportation fuel from each dispensing location.

(4) Copies of all documentation required under § 80.125(d)(2)(ii), as applicable.

(5) Documentation showing how the number of RINs separated was determined using the information specified in paragraphs (e)(1) through (4) of this section and the applicable RIN separation reports.

(f) *Renewable fuel producers that use biogas as a biointermediate or RNG as a feedstock.* In addition to the records required under paragraph (a) of this section, a renewable fuel producer that uses biogas as a biointermediate or RNG as a feedstock must keep all the following records:

(1) Documentation supporting the volume of renewable fuel produced from biogas used as a biointermediate or RNG that was used as a feedstock.

(2) For biogas, all the following additional information:

(i) For each facility, documentation supporting the volume of biogas, in Btu HHV and scf, that was used as a biointermediate.

(ii) Copies of all applicable contracts over the past 5 years with each biointermediate producer.

(3) For RNG, all the following additional information:

(i) Documentation supporting the volume of RNG, in Btu LHV, withdrawn from the natural gas commercial pipeline system.

(ii) Documentation supporting the retirement of RINs for RNG used as a feedstock (*e.g.,* contracts, purchase orders, invoices).

**§ 80.150 Product transfer documents.**

(a) *General requirements*—(1) *PTD contents.* On each occasion when any person transfers title of any biogas or imported RNG without assigned RINs, the transferor must provide the transferee PTDs that include all the following information:

(i) The name, EPA-issued company and facility IDs, and address of the transferor.

(ii) The name, EPA-issued company and facility IDs, and address of the transferee.

(iii) The volume (in Btu HHV for biogas or Btu LHV for RNG) of the product being transferred by D code and verification status.

(iv) The location of the product at the time of the transfer.

(v) The date of the transfer.

(vi) Period of production.

(2) *Other PTD requirements.* A party must also include any applicable PTD information required under § 80.1453 or 40 CFR part 1090, subpart L.

(b) *Additional PTD requirements for transfers of biogas.* In addition to the information required in paragraph (a) of this section, on each occasion when any person transfers title of biogas, the transferor must provide the transferee PTDs that include all the following information:

(1) An accurate and clear statement of the applicable designation of the biogas.

(2) If the biogas is designated as a biointermediate, any applicable requirement specified in § 80.1453(f).

(3) One of the following statements, as applicable:

(i) For biogas designated for use to produce renewable CNG/LNG, ''This volume of biogas is designated and intended for use to produce renewable CNG/LNG.''

(ii) For biogas designated for use to produce RNG, ''This volume of biogas is designated and intended for use to produce renewable natural gas.''

(iii) For biogas designated for use as a biointermediate, the language found at § 80.1453(f)(1)(vi).

(iv) For biogas designated for use as process heat or energy under § 80.1426(f)(12) or (13), ''This volume of biogas is designated and intended for use as process heat or energy.''

(c) *PTD requirements for custodial transfers of RNG.* On each occasion when custody of RNG is transferred prior to injection into a pipeline interconnect (*e.g.,* via truck), the transferor must provide the transferee PTDs that include all the following information:

(1) The applicable information listed in paragraph (a) of this section.

(2) The following statement, ''This volume of RNG is designated and intended for transportation use and may not be used for any other purpose.''

(d) *PTD requirements for imported RIN-less RNG.* On each occasion when title of RIN-less RNG is transferred and ultimately imported into the covered location, the transferor must provide the transferee PTDs that include all the following information:

(1) The applicable information listed in paragraph (a) of this section.

(2) The following statement, ''This volume of RNG is designated and intended for transportation use in the contiguous United States and may not be used for any other purpose.''

(3) The name, EPA-issued company and facility IDs, and address of the contracted RNG importer under § 80.160(e).

(4) The name, EPA-issued company and facility IDs, and address of the transferee.

**§ 80.155 Sampling, testing, and measurement.**

(a) *Biogas and RNG continuous measurement.* Any party required to measure the volume of biogas, RNG, or renewable CNG/LNG under this subpart must continuously measure using meters that comply with the requirements in paragraphs (a)(1) and (2) of this section, or have an accepted alternative measurement protocol as specified in paragraph (a)(3) of this section:

(1) In-line GC meters compliant with ASTM D7164 (incorporated by reference, see § 80.12), including sections 9.2, 9.3, 9.4, 9.5, 9.7, 9.8, and 9.11 of ASTM D7164.

(2) Flow meters compliant with one of the following:

(i) API MPMS 14.3.1, API MPMS 14.3.2, API MPMS 14.3.3, and API MPMS 14.3.4 (incorporated by reference, see § 80.12).

(ii) API MPMS 14.12 (incorporated by reference, see § 80.12).

(iii) EN 17526 (incorporated by reference, see § 80.12) compatible with gas type H.

(3) EPA may accept an alternative measurement protocol if all the following conditions are met:

(i) The party demonstrates that they are unable to continuously measure using meters that comply with the requirements in paragraphs (a)(1) and (2) of this section, as applicable.

(ii) The party demonstrates that the alternative measurement protocol is at least as accurate and precise as the methods specified in paragraphs (a)(1) and (2) of this section, as applicable.

(b) *Biogas and RNG sampling and testing.* Any party required to sample and test biogas or RNG under this subpart must do so as follows:

(1) Collect representative samples of biogas or RNG using API MPMS 14.1 (incorporated by reference, see § 80.12).

(2) Perform all the following measurements on each representative sample:

(i) Methane, carbon dioxide, nitrogen, and oxygen using EPA Method 3C (see Appendix A–2 to 40 CFR part 60).

(ii) Hydrogen sulfide and total sulfur using ASTM D5504 (incorporated by reference, see § 80.12).

(iii) Siloxanes using ASTM D8230 (incorporated by reference, see § 80.12).

(iv) Moisture using ASTM D4888 (incorporated by reference, see § 80.12).

(v) Hydrocarbon analysis using EPA Method 18 (see Appendix A–6 to 40 CFR part 60).

(vi) Heating value and relative density using ASTM D3588 (incorporated by reference, see § 80.12).

(vii) Additional components specified in the natural gas specifications submitted under § 80.135(d)(5) or specified by EPA as a condition of registration under this part.

(viii) Carbon-14 analysis using ASTM D6866 (incorporated by reference, see § 80.12).

(c) *Digester feedstock.* Any party required to test for total solids and volatile solids of a digester feedstock under this subpart must do so as follows:

(1) Samples must be tested in accordance with Part G of SM 2540 (incorporated by reference, see § 80.12).

(2) Samples must be obtained, stored, and tested in accordance with Part A of SM 2540, including Sections 2, 3, and 5 (Sources of Error and Variability, Sample Handling and Preservation, and Quality Control).

(3) Parties must test each daily representative sample under paragraphs (c)(1) and (2) of this section unless the party has a composite sampling plan submitted to EPA under § 80.135(c)(10)(vi)(D). Parties with a composite sampling plan must either test each daily representative sample or test samples in accordance with Part A of SM 2540 and as specified in the facility's composite sampling plan.

(d) *Digester operations.* Any biogas producer required to measure or calculate digester operating conditions under this subpart must determine digester operating conditions for each mixed digester that meet all the following requirements:

(1) Digester temperature readings must be recorded no less frequent than every 30 minutes and represent the average temperature in the tank.

(2) Digester hydraulic and solids mean residence times must be calculated no less frequent than once a day using measurements of inflows, outflows, and tank levels, as applicable.

(3) Other parameters must be measured and calculated as specified in the facility's registration under § 80.135(c)(10)(vi)(A)(*4*).

(e) *Third parties.* Samples required to be obtained under this subpart may be collected and analyzed by third parties.

(f) *Unit conversions.* A party converting between Btu HHV and Btu LHV for biogas, treated biogas, natural gas, or CNG/LNG must use the ratio of HHV and LHV of methane as specified in ASTM D3588 (incorporated by reference, see § 80.12).

(g) *Liquid measurement and standardization.* Any substance that is liquid at STP must be measured in gallons and standardized according to § 80.1426(f)(8).

**§ 80.160 RNG importers, foreign biogas producers, and foreign RNG producers.**

(a) *Applicability.* The provisions of this section apply to any RNG importer or any foreign party subject to requirements of this subpart outside the United States.

(b) *General requirements.* Any foreign party must meet all the following requirements:

(1) *Letter from RCO.* The foreign party must provide a letter signed by the RCO that commits the foreign party to the applicable provisions specified in paragraphs (b)(4) and (c) of this section as part of their registration under § 80.135.

(2) *Bond posting.* A foreign party that generates RINs must meet the bond requirements of § 80.1466(h).

(3) *Foreign RIN owners.* A foreign party that owns RINs must meet the requirements of § 80.1467, including any foreign party that separates or retires RINs under § 80.125.

(4) *Foreign party commitments.* Any foreign party must commit to the following provisions as a condition of being registered as a foreign party under this subpart:

(i) Any EPA inspector or auditor must be given full, complete, and immediate access to conduct inspections and audits of all facilities subject to this subpart.

(A) Inspections and audits may be either announced in advance by EPA, or unannounced.

(B) Access will be provided to any location where:

(*1*) Biogas, RNG, biointermediate, or biogas-derived renewable fuel is produced.

(*2*) Documents related to the foreign party operations are kept.

(*3*) Any product subject to this subpart (*e.g.,* biogas, RNG, biointermediates, or biogas-derived renewable fuel) that is stored or transported outside the United States between the foreign party's facility and the point of importation into the United States, including storage tanks, vessels, and pipelines.

(C) EPA inspectors and auditors may be EPA employees or contractors to EPA.

(D) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(E) Inspections and audits may include review and copying of any documents related to the following:

(*1*) The volume or properties of any product subject to this subpart produced or delivered to a renewable fuel production facility.

(*2*) Transfers of title or custody to the any product subject to this subpart.

(*3*) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this subpart, including work papers.

(*4*) Records required under § 80.145.

(*5*) Any records related to claims made during registration.

(F) Inspections and audits by EPA may include interviewing employees.

(G) Any employee of the foreign party must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(H) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 business days.

(I) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(ii) An agent for service of process located in the District of Columbia will be named, and service on this agent constitutes service on the foreign party or any employee of the party for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(iii) The forum for any civil or criminal enforcement action related to the provisions of this subpart for violations of the Clean Air Act or regulations promulgated thereunder are governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(iv) United States substantive and procedural laws apply to any civil or criminal enforcement action against the foreign party or any employee of the foreign party related to the provisions of this subpart.

(v) Applying to be an approved foreign party under this subpart, or producing or exporting any product subject to this subpart under such approval, and all other actions to comply with the requirements of this subpart relating to such approval constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign party, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign party under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(vi) The foreign party, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors for actions performed within the scope of EPA employment or contract related to the provisions of this subpart.

(vii) In any case where a product produced at a foreign facility is stored or transported by another company between the foreign facility and the point of importation to the United States, the foreign party must obtain from each such other company a commitment that meets the requirements specified in paragraphs (b)(4)(i) through (vi) of this section before the product is transported to the United States, and these commitments must be included in the foreign party's application to be a registered foreign party under this subpart.

(c) *Sovereign immunity.* By submitting an application to be a registered foreign party under this subpart, or by producing or exporting any product subject to this subpart to the United States under such registration, the foreign party, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the party, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign party under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(d) *English language reports.* Any document submitted to EPA by a foreign party must be in English, or must include an English language translation.

(e) *Foreign RNG producer contractual relationship.* A non-RIN generating foreign RNG producer must establish a contractual relationship with an RNG importer, prior to the sale of RIN-less RNG.

(f) *Withdrawal or suspension of registration.* EPA may withdraw or suspend a foreign party's registration where any of the following occur:

(1) The foreign party fails to meet any requirement of this subpart.

(2) The foreign government fails to allow EPA inspections or audits as provided in paragraph (b)(4)(i) of this section.

(3) The foreign party asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) The foreign party fails to pay a civil or criminal penalty that is not satisfied using the bond required under paragraph (b)(2) of this section.

(g) *Additional requirements for applications, reports, and certificates.* Any application for registration as a foreign party, or any report, certification, or other submission required under this subpart by the foreign party, must be:

(1) Submitted using formats and procedures specified by EPA.

(2) Signed by the RCO of the foreign party's company.

(3) Contain the following declarations:

(i) *Certification.*

''I hereby certify:

That I have actual authority to sign on behalf of and to bind [NAME OF FOREIGN PARTY] with regard to all statements contained herein.

That I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subparts E and M, and that the information is material for determining compliance under these regulations.

That I have read and understand the information being Certified or submitted, and this information is true, complete, and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof.''

(ii) *Affirmation.*

''I affirm that I have read and understand the provisions of 40 CFR part 80, subparts E and M, including 40 CFR 80.160, 80.1466, and 80.1467 apply to [NAME OF FOREIGN PARTY]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete, or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''

(h) *Requirements for RNG importers.* An RNG importer must meet all the following requirements:

(1) For each imported batch of RNG, the RNG importer must have an independent third party that meets the requirements of § 80.1450(b)(2)(i) and (ii) do all the following:

(i) Determine the volume of RNG, in Btu LHV, injected into the natural gas commercial pipeline system as specified in § 80.155.

(ii) Determine the name and EPA-assigned company and facility identification numbers of the foreign non-RIN generating RNG producer that produced the RNG.

(2) The independent third party must submit reports to the foreign non-RIN generating RNG producer and the RNG importer within 30 days following the date the RNG was injected into a natural gas commercial pipeline system for import into the United States containing all the following:

(i) The statements specified in paragraph (g) of this section.

(ii) The name of the foreign non-RIN generating RNG producer, containing the information specified in paragraph (g) of this section, and including the identification of the natural gas commercial pipeline system terminal at which the product was offloaded.

(iii) PTDs showing the volume of RNG, in Btu LHV, transferred from the foreign non-RIN generating RNG producer to the RNG importer.

(3) The RNG importer and the independent third party must keep records of the audits and reports required under paragraphs (h)(1) and (2) of this section for five years from the date of creation.

**§ 80.165 Attest engagements.**

(a) *General provisions.* (1) The following parties must arrange for annual attestation engagement using agreed-upon procedures:

(i) Biogas producers.

(ii) RNG producers.

(iii) RNG importers.

(iv) Biogas closed distribution system RIN generators.

(v) RNG RIN separators.

(vi) Renewable fuel producers that use RNG as a feedstock.

(2) The auditor performing attestation engagements required under this subpart must meet the requirements in 40 CFR 1090.1800(b).

(3) The auditor must perform attestation engagements separately for each biogas production facility, RNG production facility, and renewable fuel production facility, as applicable.

(4) Except as otherwise specified in this section, attest auditors may use the representative sampling procedures specified in 40 CFR 1090.1805.

(5) Except as otherwise specified in this section, attest auditors must prepare and submit the annual attestation engagement following the procedures specified in 40 CFR 1090.1800(d).

(b) *General procedures for biogas producers.* An attest auditor must conduct annual attestation audits for biogas producers using the following procedures:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of all the following:

(A) The biogas producer's registration information submitted under §§ 80.135 and 80.1450.

(B) All reports submitted under §§ 80.140 and 80.1451.

(ii) For each biogas production facility, confirm that the facility's registration is accurate based on the activities reported during the compliance period and confirm any related updates were completed prior to conducting regulated activities at the facility and report as a finding any exceptions.

(iii)(A) Report the date of the last engineering review conducted under §§ 80.135(b)(3) and 80.1450(b), as applicable.

(B) Report as a finding if the last engineering review is outside of the schedule specified in § 80.1450(d)(3)(ii).

(iv) Confirm that the biogas producer submitted all reports required under §§ 80.140 and 80.1451 for activities performed during the compliance period and report as a finding any exceptions.

(2) *Measurement method review.* The auditor must review measurement methods for each meter as follows:

(i) Obtain records related to measurement under § 80.145(a)(1)(vi).

(ii)(A) Identify and report the name of the method(s) used for measuring the volume of biogas, in Btu HHV and scf.

(B) Report as a finding any method that is not specified in § 80.155 or the biogas producer's registration.

(iii)(A) Identify whether maintenance and calibration records were kept for each meter and report the last date of calibration.

(B) Report as a finding if no records were obtained.

(3) *Listing of batches.* The auditor must review listings of batches as follows:

(i) Obtain the batch reports submitted under § 80.140.

(ii) Compare the reported volume for each batch to the measured volume and report as a finding any exceptions.

(4) *Testing of biogas transfers.* The auditor must review biogas transfers as follows:

(i) Obtain the associated PTD for each batch of biogas produced during the compliance period.

(ii) Using the batch number, confirm that the correct PTD is obtained for each batch and compare the volume, in Btu HHV and scf, on each batch report to the associated PTD and report as a finding any exceptions.

(iii) Confirm that the PTD associated with each batch contains all applicable language requirements under § 80.150 and report as a finding any exceptions.

(c) *General procedures for RNG producers and importers.* An attest auditor must conduct annual attestation audits for RNG producers and importers using the following procedures, as applicable:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of all the following:

(A) The RNG producer or importer's registration information submitted under §§ 80.135 and 80.1450.

(B) All reports submitted under §§ 80.140 and 80.1451.

(ii) For each RNG production facility, confirm that the facility's registration is accurate based on the activities reported during the compliance period and confirm any related updates were completed prior to conducting regulated activities at the facility and report as a finding any exceptions.

(iii)(A) Report the date of the last engineering review conducted under §§ 80.135(b)(3) and 80.1450(b), as applicable.

(B) Report as a finding if the last engineering review is outside of the schedule specified in § 80.1450(d)(3)(ii).

(iv) Confirm that the RNG producer or importer submitted all reports required under §§ 80.140 and 80.1451 for activities performed during the compliance period and report as a finding any exceptions.

(2) *Feedstock received.* The auditor must perform an inventory of biogas received as follows:

(i) Obtain copies of all the following:

(A) Records documenting the source and volume of biogas, in Btu and scf, received by the RNG producer.

(B) Records showing the volume of biogas used to produce RNG, in Btu HHV and scf, and the volume of RNG produced, in Btu HHV and scf.

(C) Records showing whether non-renewable components were blended into RNG.

(ii) Report the number of parties the RNG producer received biogas from and the total volume received separately from each party.

(iii)(A) Report the total volume of biogas used to produce RNG, in Btu HHV and scf, and the total volume of RNG produced, in Btu HHV and scf.

(B) Report as a finding if the volume of RNG produced is greater than the volume of biogas used to produce RNG, in Btu HHV.

(iv) Report as a finding if any RINs were generated for the non-renewable components of the blended batch.

(3) *Measurement method review.* The auditor must review measurement methods for each meter as follows:

(i) Obtain records related to measurement under § 80.145(a)(1)(vi).

(ii)(A) Identify and report the name of the method(s) used for measuring the volume of RNG, in Btu and in scf.

(B) Report as a finding any method that is not specified in § 80.155 or the RNG producer's registration.

(iii) Identify whether maintenance and calibration records were kept and report as a finding if no records were obtained.

(4) *Listing of batches.* The auditor must review listings of batches as follows:

(i) Obtain the batch reports submitted under § 80.140.

(ii) Compare the reported volume for each batch to the measured volume and report as a finding any exceptions.

(iii) Report as a finding any batches with reported values that did not meet the natural gas specifications submitted under § 80.135(d)(5).

(5) *Testing of RNG transfers.* The auditor must review RNG transfers as follows:

(i) Obtain the associated PTD for each batch of RNG produced or imported during the compliance period.

(ii) Using the batch number, confirm that the correct PTD is obtained for each batch and compare the volume, in Btu and scf, on each batch report to the associated PTD and report as a finding any exceptions.

(iii) Confirm that the PTD associated with each batch contains all applicable language requirements under § 80.150 and report as a finding any exceptions.

(6) *RNG RIN generation.* The auditor must perform the following procedures for monthly RIN generation:

(i) Obtain the RIN generation reports submitted under § 80.1451.

(ii) Compare the number of RINs generated for each batch to the batch report and report as a finding any exceptions.

(iii)(A) Compare the number of RINs generated multiplied by 77,000 Btu to the amount of RNG injected into the natural gas commercial pipeline system.

(B) Report as a finding if the volume of RNG injected is less than the number of RINs generated multiplied by 77,000 Btu.

(d) *General procedures for biogas closed distribution system RIN generators.* An attest auditor must conduct annual attestation audits for biogas closed distribution system RIN generators using the following procedures:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of all the following:

(A) The biogas closed distribution system RIN generator's registration information submitted under § 80.135.

(B) All reports submitted under § 80.140.

(ii) Confirm that the biogas closed distribution system RIN generator's registration is accurate based on the activities reported during the compliance period and that any required updates were completed prior to conducting regulated activities and report as a finding any exceptions.

(iii) Confirm that the biogas closed distribution system RIN generator submitted all reports required under §§ 80.140 and 80.1451 for activities performed during the compliance period and report as a finding any exceptions.

(2) *RIN generation.* The auditor must complete all applicable requirements specified in § 80.1464.

(e) *General procedures for RNG RIN separators.* An attest auditor must conduct annual attestation audits for RNG RIN separators using the following procedures:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of all the following:

(A) The RNG RIN separator's registration information submitted under §§ 80.135 and 80.1450.

(B) All reports submitted under §§ 80.140 and 80.1451.

(ii) Confirm that the RNG RIN separator's registration is accurate based on the activities reported during the compliance period and that any required updates were completed prior to conducting regulated activities and report as a finding any exceptions.

(iii) Confirm that the RNG RIN separator submitted all reports required under §§ 80.140 and 80.1451 for activities performed during the compliance period and report as a finding any exceptions.

(2) *RIN separation events.* The auditor must review records supporting RIN separation events as follows:

(i) Obtain copies of all the following:

(A) RIN separation reports submitted under §§ 80.140(e) and 80.1452.

(B) RNG withdrawal records required under § 80.145(e).

(ii)(A) Compare the volume of RNG, in Btu LHV, withdrawn from the natural gas commercial pipeline system to the reported number of separated RINs multiplied by 77,000 Btu used to produce the renewable CNG/LNG.

(B) Report as a finding if the volume of RNG, in Btu LHV, is less than the number of separated RINs multiplied by 77,000 Btu.

(iii)(A) Compare the volume of renewable CNG/LNG, in Btu LHV, to the reported number of separated RINs multiplied by 77,000 Btu.

(B) Report as a finding if the volume of renewable CNG/LNG, in Btu LHV, is less than the number of separated RINs multiplied by 77,000 Btu.

(3) *RIN owner.* The auditor must complete all the requirements specified in § 80.1464(c).

(f) *General procedures for renewable fuel producers that use RNG as a feedstock.* An attest auditor must conduct annual attestation audits for renewable fuel producers that use RNG as a feedstock using the following procedures:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of all the following:

(A) The renewable fuel producer's registration information submitted under § 80.135.

(B) All reports submitted under § 80.140.

(ii) Confirm that the renewable fuel producer's registration is accurate based on the activities reported during the compliance period and that any required updates were completed prior to conducting regulated activities and report as a finding any exceptions.

(iii) Confirm that the renewable fuel producers submitted all reports required under §§ 80.140 and 80.1451 for activities performed during the compliance period and report as a finding any exceptions.

(2) *RIN retirements.* The attest auditor must review RIN retirements as follows:

(i) Obtain copies of all the following:

(A) RIN retirement reports submitted under §§ 80.140(f) and 80.1452.

(B) Records related to measurement under § 80.145(a)(1)(vi).

(ii) Compare the measured volume of RNG used as a feedstock to the reported number of RINs retired for RNG.

(iii) Report as a finding if the measured volume of RNG used as a feedstock does not match the number of RINs retired for RNG.

**§ 80.170 Quality assurance plan.**

(a) *General requirements.* This section specifies the requirements for QAPs related to the verification of RINs generated for RNG and biogas-derived renewable fuel.

(1) For the generation of Q–RINs for RNG or biogas-derived renewable fuel, the same independent third-party auditor must verify each party as follows:

(i) For RNG, all the RNG production facilities that inject into the same pipeline interconnect and all the biogas production facilities that provide feedstock to those RNG production facilities.

(ii) For renewable CNG/LNG produced from RNG, the biogas producer and the RNG producer.

(iii) For renewable CNG/LNG produced from biogas in a biogas closed distribution system, the biogas producer, the biogas closed distribution system RIN generator, and any party deemed necessary by EPA to ensure that the renewable CNG/LNG was used as transportation fuel.

(iv) For biogas-derived renewable fuel produced from biogas used as a biointermediate, the biogas producer, the producer of the biogas-derived renewable fuel, and any other party deemed necessary by EPA to ensure that the biogas-derived renewable fuel was produced under an approved pathway and used as transportation fuel.

(v) For biogas-derived renewable fuel produced from RNG used as a feedstock, the producer of the biogas-derived renewable fuel and any other party deemed necessary by EPA to ensure that the biogas-derived renewable fuel was produced under an approved pathway and used as transportation fuel.

(2) Independent third-party auditors that verify RINs generated under this subpart must meet the requirements in § 80.1471(a) through (c), (g), and (h).

(3)(i) QAPs approved by EPA to verify RINs generated under this subpart must meet the applicable requirements in § 80.1469.

(ii) EPA may revoke or void a QAP as specified in § 80.1469(e)(4) or (5).

(4) Independent third-party auditors must conduct quality assurance audits at biogas production facilities, RNG production facilities, renewable fuel production facilities, and any facility or location deemed necessary by EPA to ensure that the biogas-derived renewable fuel was produced under an approved pathway and used as transportation fuel, heating oil, or jet fuel as specified in § 80.1472.

(5) Independent third-party auditors must ensure that mass and energy balances performed under § 80.1469(c)(2) are consistent between facilities that are audited as part of the same chain.

(b) *Requirements for biogas production facilities.* In addition to the applicable elements verified under § 80.1469, the independent third-party auditor must do all the following for each biogas production facility:

(1) Verify that the biogas was measured as required under § 80.155.

(2) Verify that the PTDs for biogas transfers meet the applicable PTD requirements in §§ 80.150 and 80.1453.

(c) *Requirements for RNG production facilities.* In addition to the applicable elements verified under § 80.1469, the independent third-party auditor must do all the following for each RNG production facility:

(1) Verify that the RNG was sampled, tested, and measured as required under § 80.155.

(2) Verify that RINs were assigned, separated, and retired as required under § 80.125(c), (d), and (e), respectively.

(3) Verify that the RNG was injected into a natural gas commercial pipeline system.

(4) Verify that RINs were not generated on non-renewable components added to RNG prior to injection into a natural gas commercial pipeline system.

(d) *Requirements for renewable fuel production facilities using biogas as a biointermediate.* The independent third-party auditor must meet all the requirements specified in paragraph (b) of this section and § 80.1477 for each renewable fuel production facility using biogas as a biointermediate.

(e) *Responsibility for replacement of invalid verified RINs.* The generator of RINs for RNG or a biogas-derived renewable fuel, and the obligated party that owns the Q–RINs, are required to replace invalidly generated Q–RINs with valid RINs as specified in § 80.1431(b).

**§ 80.175 Prohibited acts and liability provisions.**

(a) *Prohibited acts.* (1) It is a prohibited act for any person to act in violation of this subpart or fail to meet a requirement that applies to that person under this subpart.

(2) No person may cause another person to commit an act in violation of this subpart.

(b) *Liability provisions*—(1) *General.* (i) Any person who commits any prohibited act or requirement in this subpart is liable for the violation.

(ii) Any person who causes another person to commit a prohibited act under this subpart is liable for that violation.

(iii) Any parent corporation is liable for any violation committed by any of its wholly-owned subsidiaries.

(iv) Each partner to a joint venture, or each owner of a facility owned by two or more owners, is jointly and severally liable for any violation of this subpart that occurs at the joint venture facility or facility owned by the joint owners, or any violation of this subpart that is committed by the joint venture operation or any of the joint owners of the facility.

(v) Any person listed in paragraphs (b)(2) through (4) of this section is liable for any violation of a prohibition specified in paragraph (a) of this section or failure to meet a requirement of any provision of this subpart regardless of whether the person violated or caused the violation unless the person establishes an affirmative defense under § 80.180.

(vi) The liability provisions of § 80.1461 also apply to any person subject to the provisions of this subpart.

(2) *Biogas liability.* When biogas is found in violation of a prohibition specified in paragraph (a) of this section or § 80.1460, the following persons are deemed in violation:

(i) The biogas producer that produced the biogas.

(ii) Any RNG producer that used the biogas to produce RNG.

(iii) Any biointermediate producer that used the biogas to produce a biointermediate.

(iv) Any person that used the biogas, RNG produced from the biogas, or biointermediate produced from the biogas to produce a biogas-derived renewable fuel.

(v) Any person that generated a RIN from a biogas-derived renewable fuel produced from the biogas, RNG produced from the biogas, or biointermediate produced from the biogas.

(vi) Any person that used the biogas or RNG produced from the biogas as process heat or energy under § 80.1426(f)(12) or (13).

(3) *RNG liability.* When RNG is found in violation of a prohibition specified in paragraph (a) of this section or § 80.1460, the following persons are deemed in violation:

(i) The biogas producer that produced the biogas used to produce the RNG.

(ii) The RNG producer that produced the RNG.

(iii) Any person that used the RNG as a feedstock.

(iv) Any person that used the RNG as process heat or energy under § 80.1426(f)(12) or (13).

(v) Any person that generated a RIN from a biogas-derived renewable fuel produced from the RNG or biointermediate produced from the RNG.

(4) *Third-party liability.* Any party allowed under this subpart to act on behalf of a regulated party and does so to demonstrate compliance with the requirements of this subpart must meet those requirements in the same way that the regulated party must meet those requirements. The regulated party and the third party are both liable for any violations arising from the third party's failure to meet the requirements of this subpart.

**§ 80.180 Affirmative defense provisions.**

(a) *Applicability.* A person may establish an affirmative defense to a violation that person is liable for under § 80.175(b) if that person satisfies all applicable elements of an affirmative defense in this section.

(1) No person that generates a RIN for biogas-derived renewable fuel may establish an affirmative defense under this section.

(2) A person that is a biogas producer may not establish an affirmative defense under this section for a violation that the biogas producer is liable for under § 80.175(b)(1) and (2).

(3) A person that is an RNG producer may not establish an affirmative defense under this section for a violation that the RNG producer is liable for under § 80.175(b)(1) and (3).

(b) *General elements.* A person may only establish an affirmative defense under this section if the person meets all the following requirements:

(1) The person, or any of the person's employees or agents, did not cause the violation.

(2) The person did not know or have reason to know that the biogas, treated biogas, RNG, biogas-derived renewable fuel, or RIN was in violation of a prohibition or requirement under this subpart.

(3) The person must have had no financial interest in the company that caused the violation.

(4) If the person self-identified the violation, the person notified EPA within five business days of discovering the violation.

(5) The person must submit a written report to the EPA including all pertinent supporting documentation, demonstrating that the applicable elements of this section were met within 30 days of the person discovering the invalidity.

(c) *Biogas producer elements.* In addition to the elements specified in paragraph (b) of this section, a biogas producer must also meet all the following requirements to establish an affirmative defense:

(1) The biogas producer conducted or arranged to be conducted a quality assurance program that includes, at a minimum, a periodic sampling, testing, and measurement program adequately designed to ensure their biogas meets the applicable requirements to produce biogas under this part.

(2) The biogas producer had all affected biogas verified by a third-party auditor under an approved QAP under §§ 80.170 and 80.1469.

(3) The PTDs for the biogas indicate that the biogas was in compliance with the applicable requirements while in the biogas producer's control.

(d) *RNG producer elements.* In addition to the elements specified in paragraph (b) of this section, an RNG producer must also meet all the following requirements to establish an affirmative defense:

(1) The RNG producer conducted or arranged to be conducted a quality assurance program that includes, at a minimum, a periodic sampling, testing, and measurement program adequately designed to ensure that the biogas used to produce their RNG meets the applicable requirements to produce biogas under this part and that their RNG meets the applicable requirements to produce RNG under this part.

(2) The RNG producer had all affected biogas and RNG verified by a third-party auditor under an approved QAP under §§ 80.170 and 80.1469.

(3) The PTDs for the biogas used to produce their RNG and for their RNG indicate that the biogas and RNG were in compliance with the applicable requirements while in the RNG producer's control.

**§ 80.185 Potentially invalid RINs.**

(a) *Identification and treatment of potentially invalid RINs (PIRs).* (1) Any RIN can be identified as a PIR by the biogas producer, the RIN generator, the independent third-party auditor that verified the RIN, or EPA.

(2) Any party listed in paragraph (a)(1) of this section must use the procedures specified in § 80.1474(b) for identification and treatment of PIRs and retire any PIRs under § 80.1434(a).

(b) *Potentially inaccurate or non-qualifying volumes of biogas-derived renewable fuel.* (1) Any party that becomes aware of a volume of biogas-derived renewable fuel that does not meet the applicable requirements for such fuel under this part must notify the next party in the production chain within 5 business days.

(i) Biointermediate producers must notify the renewable fuel producer receiving the biointermediate within 5 business days.

(ii) If the volume of biogas-derived renewable fuel was audited under § 80.170, the party must notify the independent third-party auditor within 5 business days.

(iii) Non-RIN generating foreign RNG producers must comply with the requirements of this section and notify the importer generating RINs and other parties in the production chain, as applicable.

(iv) Each notified party must notify EPA within 5 business days.

(2) Any party that is notified of a volume of biogas-derived renewable fuel that does not meet the applicable requirements for such fuel under this part must correct affected volumes of biogas-derived renewable fuel under paragraph (a)(2) of this section, as applicable.

(c) *Potential double counting.* (1)(i) When any party becomes aware of any of the following, they must notify EPA and the RIN generator, if known, within 5 business days of initial discovery:

(A) More than one RIN being generated for renewable fuel produced from the same volume of biogas, treated biogas, or RNG.

(B) More than one RIN being generated for the same volume of biogas-derived renewable fuel or RNG.

(C) A party taking credit for biogas, treated biogas, or RNG under a non-transportation program (*e.g.,* a stationary-source renewable electricity program) and also generating RINs for renewable fuel produced from that same volume of biogas, treated biogas, or RNG.

(D) A party taking credit for biogas-derived renewable fuel or RNG under a non-transportation program (*e.g.,* a stationary-source renewable electricity program) and also generating RINs for that same volume of biogas-derived renewable fuel or RNG.

(E) A party taking credit for biogas, treated biogas, or RNG used outside the covered location and also generating RINs for renewable fuel produced from that same volume of biogas, treated biogas, or RNG.

(F) A party taking credit for biogas-derived renewable fuel or RNG used outside the covered location and also generating RINs for that same volume of biogas-derived renewable fuel or RNG.

(ii) When any party becomes aware of another party separating or retiring a RIN from the same volume of RNG, they must notify EPA and the RIN generator, if known, within 5 business days of initial discovery.

(2) EPA will notify the RIN generator of the potential double counting if the party that identified the potential double counting does not know the party that generated the potentially affected RINs.

(3) Upon notification, the RIN generator must then calculate any impacts to the number of RINs generated for the volume of impacted RNG or renewable fuel. The RIN generator must then notify EPA and the independent third-party auditor, if any, of the impacted RINs within 5 business days of initial notification.

(4) For any number of RINs over-generated due to the double counting of volumes of biogas or RNG, the RIN generator must follow the applicable procedures for invalid RINs specified in § 80.1431.

(d) *Failure to take corrective action.* Any person who fails to meet a requirement under paragraph (b) or (c) of this section is liable for full performance of such requirement, and each day of non-compliance is deemed a separate violation pursuant to § 80.1460(f). The administrative process for replacement of invalid RINs does not, in any way, limit the ability of the United States to exercise any other authority to bring an enforcement action under section 211 of the Clean Air Act, the fuels regulations under this part, 40 CFR part 1090, or any other applicable law.

(e) *Replacing PIRs or invalid RINs.* The following specifications apply when retiring valid RINs to replace PIRs or invalid RINs:

(1) When a RIN is retired to replace a PIR or invalid RIN, the D code of the retired RIN must be eligible to be used towards meeting all the renewable volume obligations as the PIR or invalid RIN it is replacing, as specified in § 80.1427(a)(2).

(2) The number of RINs retired must be equal to the number of PIRs or invalid RINs being replaced.

(f) *Forms and procedures.* (1) All parties that retire RINs under this section must use forms and procedures specified by EPA.

(2) All parties that must notify EPA under this section must submit those notifications to EPA as specified in 40 CFR 1090.10.

## Subpart M—Renewable Fuel Standard

■ 10. Revise § 80.1401 to read as follows:

### § 80.1401 Definitions.

The definitions of § 80.2 apply for the purposes of this subpart M.

### § 80.1402 [Amended]

■ 11. Amend § 80.1402 by, in paragraph (f), removing the text ''notwithstanding'' and adding in its place the text ''regardless of''.

■ 12. Amend § 80.1405 by revising paragraphs (a) and (c) to read as follows:

### § 80.1405 What are the Renewable Fuel Standards?

(a) The values of the renewable fuel standards are as follows:

TABLE 1 TO PARAGRAPH (a)—ANNUAL RENEWABLE FUEL STANDARDS

| Year | Cellulosic biofuel standard (%) | Biomass-based diesel standard (%) | Advanced biofuel standard (%) | Renewable fuel standard (%) | Supplemental total renewable fuel standard (%) |
|---|---|---|---|---|---|
| 2010 | 0.004 | 1.10 | 0.61 | 8.25 | n/a |
| 2011 | n/a | 0.69 | 0.78 | 8.01 | n/a |
| 2012 | n/a | 0.91 | 1.21 | 9.23 | n/a |
| 2013 | 0.0005 | 1.13 | 1.62 | 9.74 | n/a |
| 2014 | 0.019 | 1.41 | 1.51 | 9.19 | n/a |
| 2015 | 0.069 | 1.49 | 1.62 | 9.52 | n/a |
| 2016 | 0.128 | 1.59 | 2.01 | 10.10 | n/a |
| 2017 | 0.173 | 1.67 | 2.38 | 10.70 | n/a |
| 2018 | 0.159 | 1.74 | 2.37 | 10.67 | n/a |
| 2019 | 0.230 | 1.73 | 2.71 | 10.97 | n/a |
| 2020 | 0.32 | 2.30 | 2.93 | 10.82 | n/a |
| 2021 | 0.33 | 2.16 | 3.00 | 11.19 | n/a |

TABLE 1 TO PARAGRAPH (a)—ANNUAL RENEWABLE FUEL STANDARDS—Continued

| Year | Cellulosic biofuel standard (%) | Biomass-based diesel standard (%) | Advanced biofuel standard (%) | Renewable fuel standard (%) | Supplemental total renewable fuel standard (%) |
|---|---|---|---|---|---|
| 2022 | 0.35 | 2.33 | 3.16 | 11.59 | 0.14 |
| 2023 | 0.48 | 2.58 | 3.39 | 11.96 | 0.14 |
| 2024 | 0.63 | 2.82 | 3.79 | 12.50 | n/a |
| 2025 | 0.81 | 3.15 | 4.31 | 13.13 | n/a |

* * * * *

(c) EPA will calculate the annual renewable fuel percentage standards using the following equations:

$$Std_{CB,i} = 100 * \frac{RFV_{CB,i}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$Std_{BBD,i} = 100 * \frac{RFV_{BBD,i} \times 1.6}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$Std_{AB,i} = 100 * \frac{RFV_{AB,i}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$Std_{RF,i} = 100 * \frac{RFV_{RF,i}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

Where:

$Std_{CB,i}$ = The cellulosic biofuel standard for year i, in percent.

$Std_{BBD,i}$ = The biomass-based diesel standard for year i, in percent.

$Std_{AB,i}$ = The advanced biofuel standard for year i, in percent.

$Std_{RF,i}$ = The renewable fuel standard for year i, in percent.

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, or volume as adjusted pursuant to 42 U.S.C. 7545(o)(7)(D), in gallons.

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by 42 U.S.C. 7545 (o)(2)(B) for year i, in gallons.

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallons.

$RFV_{RF,i}$ = Annual volume of renewable fuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallons.

$G_i$ = Amount of gasoline projected to be used in the covered location, in year i, in gallons.

$D_i$ = Amount of diesel projected to be used in the covered location, in year i, in gallons.

$RG_i$ = Amount of renewable fuel blended into gasoline that is projected to be consumed in the covered location, in year i, in gallons.

$RD_i$ = Amount of renewable fuel blended into diesel that is projected to be consumed in the covered location, in year i, in gallons.

$GS_i$ = Amount of gasoline projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

$RGS_i$ = Amount of renewable fuel blended into gasoline that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

$DS_i$ = Amount of diesel projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

$RDS_i$ = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

$GE_i$ = The total amount of gasoline projected to be exempt in year i, in gallons, per §§ 80.1441 and 80.1442.

$DE_i$ = The total amount of diesel fuel projected to be exempt in year i, in gallons, per §§ 80.1441 and 80.1442.

* * * * *

■ 13. Amend § 80.1406 by:

■ a. Revising the section heading; and

■ b. Removing and reserving paragraph (a).

The revision reads as follows:

**§ 80.1406 Obligated party responsibilities.**

* * * * *

**§ 80.1407 [Amended]**

■ 14. Amend § 80.1407 by:

■ a. In paragraphs (a)(1) through (4), removing the text ''48 contiguous states or Hawaii'' wherever it appears and adding in its place the text ''covered location'';

■ b. In paragraphs (b) and (d), removing the text ''as defined in'' and adding in its place the text ''per'';

■ c. In paragraph (e), removing the text ''*MVNRLM diesel fuel* at § 80.2'' and adding in its place the text ''MVNRLM diesel fuel''; and

■ d. In paragraph (f)(5), removing the text ''48 United States and Hawaii'' and adding in its place the text ''covered location''.

■ 15. Amend § 80.1415 by:

■ a. In paragraph (b)(2), removing the text ''(mono-alkyl ester)'';

■ b. Revising paragraph (b)(5);

■ c. In paragraph (b)(6), removing the text ''kW-hr'' and adding in its place the text ''kWh'';

■ d. Revising paragraph (b)(7);

■ e. In paragraph (c)(1), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ f. In paragraph (c)(2)(ii), removing the text ''derived'' and adding in its place the text ''produced''; and
■ g. In paragraph (c)(5), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

The revisions read as follows:

**§ 80.1415 How are equivalence values assigned to renewable fuel?**

* * * * *

(b) * * *

(5) 77,000 Btu LHV of renewable CNG/LNG or RNG shall represent one gallon of renewable fuel with an equivalence value of 1.0.

* * * * *

(7) For all other renewable fuels, a producer or importer must submit an application to EPA for an equivalence value following the provisions of paragraph (c) of this section. A producer or importer may also submit an application for an alternative equivalence value pursuant to paragraph (c) of this section if the renewable fuel is listed in this paragraph (b), but the producer or importer has reason to believe that a different equivalence value than that listed in this paragraph (b) is warranted.

* * * * *

**§ 80.1416 [Amended]**

■ 16. Amend § 80.1416 by:
■ a. In paragraphs (b)(1)(vii) and (b)(2)(vii), removing the text ''The Administrator'' and adding in its place the text ''EPA'';
■ b. In paragraph (c)(4), removing the text ''definitions in § 80.1401'' and adding in its place the text ''definition''; and
■ c. In paragraph (d), removing the text ''The Administrator'' and adding in its place the text ''EPA''.

■ 17. Amend § 80.1426 by:
■ a. Revising paragraph (a)(1) introductory text;
■ b. In paragraph (a)(1)(iv), removing the text ''renewable'';
■ c. Revising paragraphs (b)(1) and (c)(1) and (2);
■ d. Removing and reserving paragraph (c)(3);
■ e. Revising paragraph (c)(6);
■ f. In paragraph (c)(7), removing the text ''§ 80.1401'' and adding in its place the text ''§ 80.2'';
■ g. Adding a sentence to the end of paragraph (d)(1) introductory text;
■ h. Revising paragraphs (e)(1) and (f)(1)(i);
■ i. Moving table 1 to § 80.1426 and table 2 to § 80.1426 immediately following paragraph (f)(1) to the end of the section;
■ j. In paragraph (f)(2)(i), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ k. In paragraph (f)(2)(ii), removing the text ''Table 1 to this section, or a D code as approved by the Administrator, which'' and adding in its place the text ''the approved pathway that'';
■ l. In paragraph (f)(3)(i), removing the text ''Table 1 to this section, or a D code as approved by the Administrator, which'' and adding in its place the text ''the approved pathways that'';
■ m. In paragraph (f)(3)(ii), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ n. In paragraph (f)(3)(iii), removing the text ''$EV_i$'' wherever it appears and adding in its place the text ''$EqV_i$'';
■ o. In paragraph (f)(3)(iv), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ p. Revising paragraph (f)(3)(v);
■ q. Removing table 3 to § 80.1426 immediately following paragraph (f)(3)(v);
■ r. Revising paragraph (f)(3)(vi);
■ s. Removing table 4 to § 80.1426 immediately following paragraph (f)(3)(vi)(A);
■ t. In paragraphs (f)(4)(i)(A)(*1*) and (f)(4)(i)(B), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ u. In paragraph (f)(4)(iv), removing the text ''80.1468'' and adding in its place the text ''80.12'';
■ v. In paragraphs (f)(5)(iv)(A) and (B), and (f)(5)(v), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ w. In paragraph (f)(5)(v), removing the text ''biogas-derived fuels'' and adding in its place the text ''biogas-derived renewable fuel'';
■ x. In paragraph (f)(5)(vi), removing the text ''Table 1 to this section, or a D code as approved by the Administrator, which'' and adding in its place the text ''the approved pathway that'';
■ y. Revising paragraph (f)(6) introductory text;
■ z. In paragraph (f)(6)(i), removing the text ''EV'' wherever it appears and adding in its place the text ''EqV'';
■ aa. In paragraphs (f)(7)(v)(A) and (B), removing the text ''§ 80.1468'' wherever it appears and adding in its place the text ''§ 80.12'';
■ bb. In paragraph (f)(8)(ii) introductory text, removing the text ''(mono-alkyl esters)'';
■ cc. In paragraphs (f)(8)(ii)(B) and (f)(9)(ii), removing the text ''§ 80.1468'' wherever it appears and adding in its place the text ''§ 80.12'';
■ dd. In paragraph (f)(10)(i)(A), removing the text ''the Administrator'' and adding in its place the text ''EPA'';
■ ee. Revising paragraph (f)(10)(ii);
■ ff. In paragraph (f)(11)(i)(A), removing the text ''the Administrator'' and adding in its place the text ''EPA'';
■ gg. Revising paragraphs (f)(11)(ii), (f)(12), (f)(13) introductory text, and (f)(13)(iii) through (v);
■ hh. Removing paragraph (f)(13)(vi);
■ ii. Revising paragraphs (f)(15), (f)(17), and (g)(1)(i) introductory text;
■ jj. In paragraph (g)(1)(iii), removing the text ''48 contiguous states plus Hawaii'' wherever it appears and adding in its place the text ''covered location'';
■ kk. Revising paragraph (g)(2) introductory text; and
■ ll. In paragraphs (g)(3) introductory text, (g)(5)(i) introductory text, (g)(7) introductory text, (g)(7)(i) introductory text, and (g)(10) introductory text, removing the text ''48 contiguous states plus Hawaii'' wherever it appears and adding in its place the text ''covered location''.

The revisions and additions read as follows:

**§ 80.1426 How are RINs generated and assigned to batches of renewable fuel?**

(a) * * *

(1) Renewable fuel producers, importers of renewable fuel, and other parties allowed to generate RINs under this part may only generate RINs to represent renewable fuel if they meet the requirements of paragraphs (b) and (c) of this section and if all the following occur:

* * * * *

(b) * * *

(1) Except as provided in paragraph (c) of this section, a RIN may only be generated by a renewable fuel producer or importer for a batch of renewable fuel that satisfies the requirements of paragraph (a)(1) of this section if it is produced or imported for use as transportation fuel, heating oil, or jet fuel in the covered location.

* * * * *

(c) * * *

(1) No person may generate RINs for fuel that does not satisfy the requirements of paragraph (a)(1) of this section.

(2) A party must not generate RINs for renewable fuel that is not produced for use in the covered location.

* * * * *

(6) A party is prohibited from generating RINs for a volume of fuel that it produces if the fuel has been produced by a process that uses a renewable fuel as a feedstock, and the renewable fuel that is used as a

feedstock was produced by another party, except that RINs may be generated for such fuel if allowed by the EPA in response to a petition submitted pursuant to § 80.1416 and the petition approval specifies a mechanism to prevent double counting of RINs or where RINs are generated for RNG.

* * * * *

(d) * * *

(1) * * * Biogas producers and RNG producers must use the definitions of batch for biogas and RNG in §§ 80.105(j) and 80.110(j), respectively.

* * * * *

(e) * * *

(1) Except as provided in paragraph (g) of this section for delayed RINs, the producer or importer of renewable fuel must assign all RINs generated from a specific batch of renewable fuel to that batch of renewable fuel.

* * * * *

(f) * * *

(1) * * *

(i) D codes must be used in RINs generated by producers or importers of renewable fuel according to approved pathways or as specified in paragraph (f)(6) of this section.

* * * * *

(3) * * *

(v) If a producer produces batches that are comprised of a mixture of fuel types with different equivalence values and different applicable D codes, then separate values for $V_{RIN}$ must be calculated for each category of renewable fuel according to the following formula. All batch-RINs thus generated must be assigned to unique batch identifiers for each portion of the batch with a different D code.

$$V_{RIN,DX} = EqV_{DX} * V_{S,DX}$$

Where:

$V_{RIN,DX}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that must be generated for the portion of the batch with a D code of X.

$EqV_{DX}$ = Equivalence value for the portion of the batch with a D code of X, per § 80.1415.

$V_{S,DX}$ = Standardized volume at 60 °F of the portion of the batch that must be assigned a D code of X, in gallons, per paragraph (f)(8) of this section.

(vi)(A) If a producer produces a single type of renewable fuel using two or more different feedstocks that are processed simultaneously, and each batch is comprised of a single type of fuel, then the number of gallon-RINs that must be generated for a batch of renewable fuel and assigned a particular D code must be calculated as follows:

$$V_{RIN,DX} = EqV * V_S * \frac{FE_{DX}}{FE_{total}}$$

Where:

$V_{RIN,DX}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that must be generated for a batch of renewable fuel with a D code of X.

EqV = Equivalence value for the renewable fuel per § 80.1415.

$V_S$ = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, per paragraph (f)(8) of this section.

$FE_{DX}$ = The total feedstock energy from all feedstocks whose pathways have been assigned a D code of X, in Btu HHV, per paragraphs (f)(3)(vi)(B) and (C) of this section.

$FE_{total}$ = The total feedstock energy from all feedstocks, in Btu HHV, per paragraphs (f)(3)(vi)(B) and (C) of this section.

(B) Except for biogas produced from anaerobic digestion, the feedstock energy value of each feedstock must be calculated as follows:

$$FE_{DX,i} = M_i * (1 - m_i) * CF_i$$

Where:

$FE_{DX,i}$ = The amount of energy from feedstock i that forms energy in the renewable fuel and whose pathway has been assigned a D code of X, in Btu HHV.

$M_i$ = Mass of feedstock i, in pounds, measured on a daily or per-batch basis.

$m_i$ = Average moisture content of feedstock i, as a mass fraction.

$CF_i$ = Converted fraction in annual average Btu HHV/lb, except as otherwise provided by § 80.1451(b)(1)(ii)(U), representing that portion of feedstock i that is converted to fuel by the producer.

(C) For biogas produced from anaerobic digestion, the volume of biogas must be measured under § 80.105(f) and the feedstock energy value of each feedstock must be calculated as specified in § 80.105(j) by substituting ‘‘feedstock energy’’ for ‘‘batch volume of biogas’’ in all cases.

* * * * *

(6) *Renewable fuel not covered by an approved pathway.* If no approved pathway applies to a producer's operations, the party may generate RINs if the fuel from its facility is produced from renewable biomass and qualifies for an exemption under § 80.1403 from the requirement that renewable fuel achieve at least a 20 percent reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions.

* * * * *

(10) * * *

(ii) RIN generators may only generate RINs for renewable CNG/LNG produced from biogas that is distributed via a closed, private, non-commercial system if all the following requirements are met:

(A) The renewable CNG/LNG was produced from renewable biomass under an approved pathway.

(B) The RIN generator has entered into a written contract for the sale or use of a specific quantity of renewable CNG/LNG for use as transportation fuel, or has obtained affidavits from all parties selling or using the renewable CNG/LNG as transportation fuel.

(C) The renewable CNG/LNG was used as transportation fuel and for no other purpose.

(D) The biogas was introduced into the closed, private, non-commercial system no later and the renewable CNG/LNG produced from the biogas was used as transportation fuel no later than December 31, 2024.

(E) RINs may only be generated on biomethane content of the renewable CNG/LNG used as transportation fuel.

* * * * *

(11) * * *

(ii) RINs for renewable CNG/LNG produced from RNG that is introduced into a commercial distribution system may only be generated if all the following requirements are met:

(A) The renewable CNG/LNG was produced from renewable biomass and qualifies for a D code in an approved pathway.

(B) The RIN generator has entered into a written contract for the sale or use of a specific quantity of RNG, taken from a commercial distribution system (*e.g.,* physically connected pipeline, barge, truck, rail), for use as transportation fuel, or has obtained affidavits from all parties selling or using the RNG taken from a commercial distribution system as transportation fuel.

(C) The renewable CNG/LNG produced from the RNG was sold for use as transportation fuel and for no other purpose.

(D) The RNG was injected into and withdrawn from the same commercial distribution system.

(E) The RNG was withdrawn from the commercial distribution system in a manner and at a time consistent with the transport of the RNG between the injection and withdrawal points.

(F) The volume of RNG injected into the commercial distribution system and the volume of RNG withdrawn are measured by continuous metering.

(G) The volume of renewable CNG/LNG sold for use as transportation fuel corresponds to the volume of RNG that was injected into and withdrawn from the commercial distribution system.

(H) No other party relied upon the volume of biogas, RNG, or renewable CNG/LNG for the generation of RINs.

(I) The RNG was introduced into the commercial distribution system no later than December 31, 2024, and the renewable CNG/LNG was used as transportation fuel no later than December 31, 2024.

(J) RINs may only be generated on biomethane content of the biogas, treated biogas, RNG, or renewable CNG/LNG.

(K)(*1*) On or after January 1, 2025, RINs may only be generated for RNG injected into a natural gas commercial pipeline system for use as transportation fuel as specified in subpart E of this part.

(*2*) RINs may be generated for RNG as specified in subpart E of this part prior to January 1, 2025, if all applicable requirements under this part are met.

* * * * *

(12) Process heat produced from combustion of biogas or RNG at a renewable fuel production facility is considered ''derived from biomass'' under an approved pathway if all the following requirements are met, as applicable:

(i) For biogas transported to the renewable fuel production facility via a biogas closed distribution system:

(A) The renewable fuel producer has entered into a written contract for the procurement of a specific volume of biogas with a specific heat content.

(B) The volume of biogas was sold to the renewable fuel production facility, and to no other facility.

(C) The volume of biogas injected into the biogas closed distribution system and the volume of biogas used as process heat were measured under § 80.155.

(ii) For RNG injected into a natural gas commercial pipeline system prior to July 1, 2024:

(A) The producer has entered into a written contract for the procurement of a specific volume of RNG with a specific heat content.

(B) The volume of RNG was sold to the renewable fuel production facility, and to no other facility.

(C) The volume of RNG was withdrawn from the natural gas commercial pipeline system in a manner and at a time consistent with the transport of RNG between the injection and withdrawal points.

(D) The volume of RNG injected into the natural gas commercial pipeline system and the volume of RNG withdrawn were measured under § 80.155.

(E) The natural gas commercial pipeline system into which the RNG was injected ultimately serves the renewable fuel production facility.

(iii) Process heat produced from combustion of biogas or RNG is not considered produced from renewable biomass if any other party relied upon the volume of biogas or RNG for the generation of RINs.

(iv) For RNG used as process heat on or after July 1, 2024, the renewable fuel producer must retire RINs for RNG as specified in § 80.125(e).

(13) In order for a renewable fuel production facility to satisfy the requirements of the advanced biofuel grain sorghum pathway, all the following requirements must be met:

* * * * *

(iii) For biogas transported to the renewable fuel production facility via a biogas closed distribution system and used as process energy, the requirements in paragraph (f)(12)(i) of this section must be met.

(iv)(A) For RNG injected into a commercial distribution system prior to July 1, 2024, and used as process energy, the requirements in paragraph (f)(12)(ii) of this section must be met.

(B) For RNG injected into a natural gas commercial pipeline system on or after July 1, 2024, and used as process energy, the renewable fuel producer must retire RINs for RNG as specified in § 80.125(e).

(v) The biogas or RNG used as process energy at the renewable fuel production facility is not considered ''produced from renewable biomass'' under an approved pathway if any other party relied upon the volume of biogas or RNG for the generation of RINs.

* * * * *

(15) *Application of formulas in paragraph (f)(3)(vi) of this section to certain producers generating D3 or D7 RINs.* If a producer seeking to generate D code 3 or 7 RINs produces a single type of renewable fuel using two or more feedstocks or biointermediates converted simultaneously, and at least one of the feedstocks or biointermediates does not have a minimum 75% average adjusted cellulosic content, one of the following additional requirements apply:

(i) If the producer is using a thermochemical process to convert cellulosic biomass into cellulosic biofuel, the producer is subject to additional registration requirements under § 80.1450(b)(1)(xiii)(A).

(ii) If the producer is using any process other than a thermochemical process, or is using a combination of processes, the producer is subject to additional registration requirements under § 80.1450(b)(1)(xiii)(B) or (C), and reporting requirements under § 80.1451(b)(1)(ii)(U), as applicable.

* * * * *

(17) *Qualifying use demonstration for certain renewable fuels.* For purposes of this section, any renewable fuel other than ethanol, biodiesel, renewable gasoline, or renewable diesel that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.12) is considered renewable fuel and the producer or importer may generate RINs for such fuel only if all the following apply:

(i) The fuel is produced from renewable biomass and qualifies to generate RINs under an approved pathway.

(ii) The fuel producer or importer maintains records demonstrating that the fuel was produced for use as a transportation fuel, heating oil or jet fuel by any of the following:

(A) Blending the renewable fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards under this part and 40 CFR part 1090.

(B) Entering into a written contract for the sale of the renewable fuel, which specifies the purchasing party must blend the fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards under this part and 40 CFR part 1090.

(C) Entering into a written contract for the sale of the renewable fuel, which specifies that the fuel must be used in its neat form as a transportation fuel, heating oil or jet fuel that meets all applicable standards.

(ii) The fuel was sold for use in or as a transportation fuel, heating oil, or jet fuel, and for no other purpose.

(g) * * *

(1) * * *

(i) The renewable fuel volumes can be described by a new approved pathway that was added after July 1, 2010.

* * * * *

(2) When a new approved pathway is added, EPA will specify in its approval action the effective date on which the new pathway becomes valid for the generation of RINs and whether the fuel in question meets the requirements of paragraph (g)(1)(ii) of this section.

* * * * *

**§ 80.1427 [Amended]**

■ 18. In § 80.1427 amend paragraph (a)(1) introductory text by removing the text ''under § 80.1406''.

■ 19. Amend § 80.1428 by revising paragraphs (a) and (b) to read as follows:

**§ 80.1428 General requirements for RIN distribution.**

(a) *RINs assigned to volumes of renewable fuel or RNG.* (1) Except as provided in §§ 80.1429 and 80.125(d), no person can separate a RIN that has been assigned to a volume of renewable fuel or RNG pursuant to § 80.1426(e).

(2) An assigned RIN cannot be transferred to another person without simultaneously transferring a volume of renewable fuel or RNG to that same person.

(3) Assigned gallon-RINs with a K code of 1 can be transferred to another person based on the following:

(i) Except for RNG, no more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another person with every gallon of renewable fuel transferred to that same person.

(ii) For RNG, the transferor of assigned RINs for RNG must transfer RINs under § 80.125(c).

(4)(i) Except for RNG, on each of the dates listed in paragraph (a)(4)(ii) of this section in any calendar year, the following equation must be satisfied for assigned RINs and volumes of renewable fuel owned by a person:

$$RIN_d \leq V_d * 2.5$$

Where:

$RIN_d$ = Total number of assigned gallon-RINs with a K code of 1 that are owned on date d.

$V_d$ = Standardized total volume of renewable fuel owned on date d, in gallons, per § 80.1426(f)(8).

(ii) The applicable dates are March 31, June 30, September 30, and December 31.

(5) Any transfer of ownership of assigned RINs must be documented on product transfer documents generated pursuant to § 80.1453.

(i) The RIN must be recorded on the product transfer document used to transfer ownership of the volume of renewable fuel or RNG to another person; or

(ii) The RIN must be recorded on a separate product transfer document transferred to the same person on the same day as the product transfer document used to transfer ownership of the volume of renewable fuel or RNG.

(b) *RINs separated from volumes of renewable fuel or RNG.*

(1) Unless otherwise specified, any person that has registered pursuant to § 80.1450 can own a separated RIN.

(2) Separated RINs can be transferred any number of times.

* * * * *

■ 20. Amend § 80.1429 by:

■ a. Revising the section heading;

■ b. In paragraphs (a)(1), (a)(2) and (b) introductory text, removing the text ''renewable fuel'' wherever it appears and adding in its place the text ''renewable fuel or RNG'';

■ c. Revising paragraph (b)(1);

■ d. Redesignating paragraph (b)(5) as paragraph (b)(5)(i);

■ e. Adding paragraph (b)(5)(ii);

■ f. In paragraph (b)(6) introductory text, removing the text ''(mono-alkyl ester)'' wherever it appears;

■ g. Revising paragraph (b)(10); and

■ h. In paragraphs (c), (d), and (e), removing the text ''renewable fuel'' and adding in its place the text ''renewable fuel or RNG''.

The revisions and addition read as follows:

**§ 80.1429 Requirements for separating RINs from volumes of renewable fuel or RNG.**

* * * * *

(b) * * *

(1) Except as provided in paragraphs (b)(7) and (9) of this section and § 80.125(d)(3), an obligated party must separate any RINs that have been assigned to a volume of renewable fuel if that party owns that volume.

* * * * *

(5) * * *

(ii)(A) Any biogas closed distribution system RIN generator that generates RINs for a batch of renewable CNG/LNG under § 80.130(b) may only separate RINs that have been assigned to that batch after the party demonstrates that the renewable CNG/LNG was used as transportation fuel.

(B) Only an RNG RIN separator may only separate the RINs that have been assigned to a volume of RNG after meeting all applicable requirements in § 80.125(d)(2).

* * * * *

(10) Any party that produces a volume of renewable fuel or RNG may separate any RINs that have been generated to represent that volume of renewable fuel or RNG if that party retires the separated RINs to replace invalid RINs according to § 80.1474.

* * * * *

**§ 80.1430 [Amended]**

■ 21. Amend § 80.1430 by, in paragraph (e)(2), removing the text ''§ 80.1468'' and adding in its place the text ''§ 80.12''.

■ 22. Amend § 80.1431 by:

■ a. Revising paragraph (a)(1)(vi);

■ b. Adding paragraphs (a)(1)(viii), (a)(1)(x), and (a)(4);

■ c. Revising paragraphs (b) introductory text and (c) introductory text; and

■ d. In paragraph (c)(7)(ii)(P), removing the text ''the Administrator'' and adding in its place the text ''that EPA''.

The revisions and additions read as follows:

**§ 80.1431 Treatment of invalid RINs.**

(a) * * *

(1) * * *

(vi) Does not represent renewable fuel or RNG.

* * * * *

(viii) Was generated for fuel that was not used in the covered location.

* * * * *

(x) Was inappropriately separated under § 80.125(d).

* * * * *

(4) If any RIN generated for a batch of renewable fuel that had RINs apportioned through § 80.1426(f)(3) is invalid, then all RINs generated for that batch of renewable fuel are deemed invalid, unless EPA in its sole discretion determines that some portion of those RINs are valid.

(b) Except as provided in paragraph (c) of this section and § 80.1473, the following provisions apply in the case of RINs that are invalid:

* * * * *

(c) Improperly generated RINs may be used for compliance provided that all the following conditions and requirements are satisfied and the RIN generator demonstrates that the conditions and requirements are satisfied through the reporting and recordkeeping requirements set forth below, that:

* * * * *

■ 23. Amend § 80.1434 by:

■ a. Revising paragraphs (a)(1) and (5); and

■ b. Redesignating paragraph (a)(11) as paragraph (a)(13) and adding new paragraphs (a)(11) and (12).

The revisions and additions read as follows:

**§ 80.1434 RIN retirement.**

(a) * * *

(1) *Demonstrate annual compliance.* Except as specified in paragraph (b) of this section or § 80.1456, an obligated party required to meet the RVO under § 80.1407 must retire a sufficient number of RINs to demonstrate compliance with an applicable RVO.

* * * * *

(5) *Spillage, leakage, or disposal of renewable fuels.* Except as provided in § 80.1432(c), in the event that a reported spillage, leakage, or disposal of any volume of renewable fuel, the owner of the renewable fuel must notify any holder or holders of the attached RINs and retire a number of gallon-RINs corresponding to the volume of spilled or disposed of renewable fuel multiplied by its equivalence value in accordance with § 80.1432(b).

* * * * *

(11) *Used to produce other renewable fuel.* Any party that uses renewable fuel

or RNG to produce other renewable fuel must retire any assigned RINs for the volume of the renewable fuel or RNG.

(12) *Expired RINs for RNG.* Any party owning RINs assigned to RNG as specified in § 80.125(e) must retire the assigned RIN.

* * * * *

**§ 80.1435 [Amended]**

■ 24. Amend § 80.1435 by:

■ a. In paragraphs (b)(1)(i) and (ii) and (b)(2)(i) through (iv), removing the text ''RIN-gallons'' wherever it appears and adding in its place the text ''gallon-RINs''; and

■ b. In paragraph (b)(2)(iii), removing the text ''48 contiguous states or Hawaii'' wherever it appears and adding in its place the text ''covered location''.

■ 25. Amend § 80.1441 by:

■ a. Revising paragraph (a)(1);

■ b. Removing and reserving paragraph (a)(3);

■ c. Removing paragraph (b)(3);

■ d. In paragraph (e)(1) and (2) introductory text, removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ e. In paragraph (e)(2)(ii), removing the text ''The Administrator'' and adding in its place the text ''EPA''.

■ f. In paragraph (e)(2)(iii), removing the text ''§ 80.1401'' wherever it appears and adding in its place the text ''§ 80.2''; and

■ g. In paragraph (g), removing the text ''defined under'' and adding in its place the text ''specified in''.

The revision reads as follows:

**§ 80.1441 Small refinery exemption.**

(a)(1) Transportation fuel produced at a refinery by a refiner is exempt from January 1, 2010, through December 31, 2010, from the renewable fuel standards of § 80.1405, and the owner or operator of the refinery is exempt from the requirements that apply to obligated parties under this subpart M for fuel produced at the refinery if the refinery meets the definition of ''small refinery'' in § 80.2 for calendar year 2006.

* * * * *

■ 26. Amend § 80.1442 by:

■ a. Removing and reserving paragraph (a)(2);

■ b. Removing paragraphs (b)(4) and (5); and

■ c. Revising paragraph (c)(1).

The revision reads as follows

**§ 80.1442 What are the provisions for small refiners under the RFS program?**

* * * * *

(c) * * *

(1) Transportation fuel produced by a small refiner pursuant to paragraph (b)(1) of this section is exempt from January 1, 2010, through December 31, 2010, from the renewable fuel standards of § 80.1405 and the requirements that apply to obligated parties under this subpart if the refiner meets all the criteria of paragraph (a)(1) of this section.

* * * * *

**§ 80.1443 [Amended]**

■ 27. Amend § 80.1443 by:

■ a. In paragraphs (a), (b), and (e) introductory text, removing the text ''the Administrator'' and adding in its place the text ''EPA''; and

■ b. In paragraph (e)(2), removing the text ''as defined in § 80.1406''.

**§ 80.1449 [Amended]**

■ 28. Amend § 80.1449 by, in paragraph (e), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

■ 29. Amend § 80.1450 by:

■ a. Revising the first sentence of paragraph (a);

■ b. Revising paragraphs (b)(1) introductory text and (b)(1)(ii);

■ c. In paragraph (b)(1)(v) introductory text, removing the text ''as defined in § 80.1401'';

■ d. Revising paragraph (b)(1)(v)(E);

■ e. Adding paragraph (b)(1)(v)(F);

■ f. In paragraph (b)(1)(vi), removing the text ''defined' and adding in its place the text ''specified'';

■ g. Adding paragraph (b)(1)(viii)(E);

■ h. In paragraphs (b)(1)(xi) introductory text, (b)(1)(xi)(A), and (B), removing the text ''§ 80.1401'' and adding in its place the text ''§ 80.2'';

■ i. In paragraph (b)(1)(xii) introductory text, removing the text ''§ 80.1468'' and adding in its place the text ''§ 80.12'';

■ j. Revising paragraph (b)(1)(xiii)(B) introductory text;

■ k. Adding paragraph (b)(1)(xiii)(C);

■ l. Revising paragraph (b)(1)(xv)(B);

■ m. Revising the first sentence of paragraph (b)(2) introductory text;

■ n. In paragraph (b)(2)(iii), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ o. Adding paragraph (b)(2)(vii);

■ p. Revising paragraphs (d)(3) and (g)(10)(ii); and

■ q. In paragraphs (g)(11)(i), (ii), (iii), and (i)(1), removing the text ''The Administrator'' and adding in its place the text ''EPA''.

The revisions and additions read as follows:

**§ 80.1450 What are the registration requirements under the RFS program?**

(a) * * * Any obligated party or any exporter of renewable fuel must provide EPA with the information specified for registration under 40 CFR 1090.805, if such information has not already been provided under the provisions of this part. * * *

(b) * * *

(1) A description of the types of renewable fuels, RNG, ethanol, or biointermediates that the producer intends to produce at the facility and that the facility is capable of producing without significant modifications to the existing facility. For each type of renewable fuel, RNG, ethanol, or biointermediate the renewable fuel producer or foreign ethanol producer must also provide all the following:

* * * * *

(ii) A description of the facility's renewable fuel, RNG, ethanol, or biointermediate production processes, including:

* * * * *

(v) * * *

(E)(*1*) For parties registered to generate RINs for renewable CNG/LNG prior to July 1, 2024, the registration requirements under paragraph (b)(1)(v)(D) under this section apply until December 31, 2024.

(*2*) For biogas producers, RNG producers, and biogas closed distribution system RIN generators not registered prior to July 1, 2024, the registration requirements under § 80.135 apply.

(F) Any other records as requested by EPA.

* * * * *

(viii) * * *

(E) The independent third-party engineer must visit all material recovery facilities as part of the engineering review site visit under § 80.1450(b)(2) and (d)(3), as applicable.

* * * * *

(xiii) * * *

(B) A renewable fuel producer seeking to generate D code 3 or D code 7 RINs, a foreign ethanol producer seeking to have its product sold as cellulosic biofuel after it is denatured, or a biointermediate producer seeking to have its biointermediate made into cellulosic biofuel, who intends to produce a single type of fuel using two or more feedstocks converted simultaneously, where at least one of the feedstocks does not have a minimum 75% adjusted cellulosic content, and who uses a process other than a thermochemical process, excluding anerobic digestion, or a combination of processes to convert feedstock into renewable fuel or biointermediate, must provide all the following:

* * * * *

(C) A renewable fuel producer seeking to generate D code 3 or D code 7 RINs or a biointermediate producer seeking to have its biointermediate made into cellulosic biofuel, who intends to produce biogas using two or more feedstocks converted simultaneously in an anaerobic digester, where at least one of the feedstocks does not have a minimum 75% adjusted cellulosic content, must supply the information specified in § 80.135(c)(10).

* * * * *

(xv) * * *

(B) A written justification which explains why each feedstock a producer lists according to paragraph (b)(1)(xv)(A) of this section meets the definition of crop residue.

* * * * *

(2) An independent third-party engineering review and written report and verification of the information provided pursuant to paragraph (b)(1) of this section and § 80.135, as applicable. * * *

* * * * *

(vii) Reports required under this paragraph (b)(2) must be electronically submitted directly to EPA by an independent third-party engineer using forms and procedures established by EPA.

* * * * *

(d) * * *

(3) All renewable fuel producers, foreign ethanol producers, and biointermediate producers must update registration information and submit an updated independent third-party engineering review as follows:

(i) For all renewable fuel producers and foreign ethanol producers registered in calendar year 2010, the updated registration information and independent third-party engineering review must be submitted to EPA by January 31, 2013, and by January 31 of no less frequent than every third calendar year thereafter.

(ii) For all renewable fuel producers, foreign ethanol producers, and biointermediate producers registered in any calendar year after 2010, the updated registration information and independent third-party engineering review must be submitted to EPA by January 31 of no less frequent than every third calendar year after the date of the first independent third-party engineering review site visit conducted under paragraph (b)(2) of this section. For example, if a renewable fuel producer arranged for a third-party engineer to conduct the first site visit on December 15, 2023, the three-year independent third-party engineer review must be submitted by January 31, 2027.

(iii) For all renewable fuel producers, the updated independent third-party engineering review must include all the following:

(A) The engineering review and written report and verification required by paragraph (b)(2) of this section.

(B) A detailed review of the renewable fuel producer's calculations and assumptions used to determine $V_{RIN}$ of a representative sample of batches of each type of renewable fuel produced since the last registration. This representative sampling must adhere to all the following, as applicable:

(*1*) The representative sample must be selected in accordance with the sample size guidelines set forth at 40 CFR 1090.1805.

(*2*) For updated independent third-party engineering reviews submitted after January 31, 2024, the representative sample must be selected from batches of renewable fuel produced through at least the second quarter of the calendar year prior to the applicable January 31 deadline.

(iv) For biointermediate producers, in addition to conducting the engineering review and written report and verification required by paragraph (b)(2) of this section, the updated independent third-party engineering review must include a detailed review of the biointermediate producer's calculations used to determine the renewable biomass and cellulosic renewable biomass proportions, as required to be reported to EPA under § 80.1451(j), of a representative sample of batches of each type of biointermediate produced since the last registration. The representative sample must be selected in accordance with the sample size guidelines set forth at 40 CFR 1090.1805.

(v) For updated independent third-party engineering reviews submitted after January 31, 2024, independent third-party engineers must conduct site visits required under this paragraph (d) no sooner than July 1 of the calendar year prior to the applicable January 31 deadline.

(vi) For updated independent third-party engineering reviews submitted after January 31, 2024, the site visits required under this paragraph (d) must occur when the renewable fuel production facility is producing renewable fuel or when the biointermediate production facility is producing biointermediates.

(vii) If a renewable fuel producer, foreign ethanol producer, or biointermediate producer updates their registration information and independent third-party engineering review prior to the next applicable January 31 deadline, and the registration information and independent third-party engineering review meet all applicable requirements under paragraphs (b)(2) and (d)(3)(iii) of this section, the next required registration information and independent third-party engineering review update is due by January 31 of every third calendar year after the date of the updated independent third-party engineering review site visit.

* * * * *

(g) * * *

(10) * * *

(ii) The independent third-party auditor submits an affidavit affirming that they have only verified RINs and biointermediates using a QAP approved under § 80.1469 and notified all appropriate parties of all potentially invalid RINs as described in § 80.1471(d).

* * * * *

■ 30. Effective February 1, 2024, amend § 80.1450 by revising paragraph (b)(2)(ii) and adding paragraphs (b)(2)(viii) through (x) to read as follows:

**§ 80.1450 What are the registration requirements under the RFS program?**

* * * * *

(b) * * *

(2) * * *

(ii) The independent third-party engineer and its contractors and subcontractors must meet the independence requirements specified in § 80.1471(b)(1), (2), (4), (5), and (7) through (12).

* * * * *

(viii) The independent third-party engineer must conduct engineering reviews as follows:

(A)(*1*) To verify the accuracy of the information provided in paragraph (b)(1)(ii) of this section, the independent third-party engineer must conduct independent calculations of the throughput rate-limiting step in the production process, take digital photographs of all process units depicted in the process flow diagram during the site visit, and certify that all process unit connections are in place and functioning based on the site visit.

(*2*) Digital photographs of a process unit are not required if the third-party engineer submits documentation demonstrating why they were unable to access certain locations due to access issues or safety concerns. EPA may not accept a registration if EPA is unable to determine whether the facility is capable of producing the requested renewable fuel, biointermediate, biogas, or RNG, as applicable, due to the lack of sufficient digital photographs of process units for the facility.

(B) To verify the accuracy of the information in paragraph (b)(1)(iii) of this section, the independent third-party engineer must obtain independent documentation from parties in contracts with the producer for any co-product sales or disposals. The independent third-party engineer may use representative sampling as specified in 40 CFR 1090.1805 to verify co-product sales or disposals.

(C) To verify the accuracy of the information provided in paragraph (b)(1)(iv) of this section, the independent third-party engineer must obtain independent documentation from all process heat fuel suppliers of the process heat fuel supplied to the facility. The independent third-party engineer may use representative sampling as specified in 40 CFR 1090.1805 to verify fuel suppliers.

(D) To verify the accuracy of the information provided in paragraph (b)(1)(v) of this section, the independent third-party engineer must conduct independent calculations of the Converted Fraction that will be used to generate RINs.

(ix) The independent third-party engineer must provide to EPA documentation demonstrating that a site visit, as specified in paragraph (b)(2) of this section, occurred. Such documentation must include digital photographs with date and geographic coordinates taken during the site visit and a description of what is depicted in the photographs.

(x) The independent third-party engineer must sign, date, and submit to EPA with the written report the following conflict of interest statement:

''I certify that the engineering review and written report required and submitted under 40 CFR 80.1450(b)(2) was conducted and prepared by me, or under my direction or supervision, in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information upon which the engineering review was conducted and the written report is based. I further certify that the engineering review was conducted and this written report was prepared pursuant to the requirements of 40 CFR part 80 and all other applicable auditing, competency, independence, impartiality, and conflict of interest standards and protocols. Based on my personal knowledge and experience, and inquiry of personnel involved, the information submitted herein is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment for knowing violations.''

* * * * *

■ 31. Amend § 80.1451 by:

■ a. In paragraph (a) introductory text, removing the text ''described in § 80.1406'' and ''described in § 80.1430'';

■ b. Revising paragraph (a)(1)(iii);

■ c. In paragraph (a)(1)(vi), removing the text ''defined'' and adding in its place the text ''specified'';

■ d. Revising paragraphs (a)(1)(viii) and (ix);

■ e. In paragraph (a)(1)(xiii), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ f. Revising paragraphs (a)(1)(xvi), (xvii), and (xviii);

■ g. In paragraph (b)(1)(ii)(O), removing the text ''as defined in § 80.1401'';

■ h. In paragraph (b)(1)(ii)(T), removing the text ''§ 80.1468'' and adding in its place the text ''§ 80.12'';

■ i. Revising paragraph (b)(1)(ii)(U) introductory text;

■ j. In paragraph (b)(1)(ii)(W), removing the text ''the Administrator'' and adding in its place the text ''that EPA'';

■ k. In paragraph (c)(1)(iii)(K), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ l. In paragraphs (c)(2)(i)(J) and (L), removing the text ''as defined in'' and adding in its place the text ''under'';

■ m. In paragraph (c)(2)(i)(R), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ n. In paragraphs (c)(2)(ii)(D)(*8*) and (*10*), removing the text ''as defined in'' and adding in its place the text ''under'';

■ o. In paragraph (c)(2)(ii)(I), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ p. In paragraph (e) introductory text, removing the text ''as defined in § 80.1401 who'' and adding in its place the text ''that'';

■ q. Adding paragraph (f)(4);

■ r. Revising paragraphs (g) introductory text, (g)(1), (g)(2) introductory text, and (g)(2)(vii) through (xi);

■ s. Adding paragraph (g)(2)(xii);

■ t. In paragraph (h)(2), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ u. In paragraph (j)(1)(xvi), removing the text ''the Administrator'' and adding in its place the text ''that EPA''; and

■ v. In paragraph (k), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

The revisions and additions read as follows:

### § 80.1451 What are the reporting requirements under the RFS program?

(a) * * *

(1) * * *

(iii) Whether the refiner is complying on a corporate (aggregate) or facility-by-facility basis.

* * * * *

(viii) The total current-year RINs by category of renewable fuel (*i.e.,* cellulosic biofuel, biomass-based diesel, advanced biofuel, renewable fuel, and cellulosic diesel), retired for compliance.

(ix) The total prior-year RINs by renewable fuel category retired for compliance.

* * * * *

(xvi) The total current-year RINs by category of renewable fuel (*i.e.,* cellulosic biofuel, biomass-based diesel, advanced biofuel, renewable fuel, and cellulosic diesel), retired for compliance that are invalid as specified in § 80.1431(a).

(xvii) The total prior-year RINs by renewable fuel category retired for compliance that are invalid as specified in § 80.1431(a).

(xviii) A list of all RINs that were retired for compliance in the reporting period and are invalid as specified in § 80.1431(a).

* * * * *

(b) * * *

(1) * * *

(ii) * * *

(U) Producers generating D code 3 or 7 RINs for cellulosic biofuel other than RNG or biogas-derived renewable fuel, and that was produced from two or more feedstocks converted simultaneously, at least one of which has less than 75% average adjusted cellulosic content, and using a combination of processes or a process other than a thermochemical process or a combination of processes, must report all the following:

* * * * *

(f) * * *

(4) *Monthly reporting schedule.* Any party required to submit information or reports on a monthly basis must submit such information or reports by the end of the subsequent calendar month.

(g) *Independent third-party auditors.* Any independent third-party auditor must submit quarterly reports as follows:

(1) The following information for each verified batch, as applicable:

(i) The audited party's name.

(ii) The audited party's EPA company registration number.

(iii) The audited party's EPA facility registration number.

(iv)(A) The renewable fuel importer's EPA facility registration number and foreign renewable fuel producer's company registration number.

(B) The RNG importer's EPA facility registration number and foreign RNG producer's company registration number.

(v) The applicable reporting period.

(vi) The quantity of RINs generated for each verified batch according to §§ 80.125, 80.130, and 80.1426.

(vii) The production date of each verified batch.

(viii) The D-code of each verified batch.

(ix) The volume of ethanol denaturant and applicable equivalence value of each verified batch.

(x) The volume of each verified batch produced.

(xi) The volume and type of each feedstock and biointermediate used to produce the verified batch.

(xii) Whether the feedstocks and biointermediates used to produce each verified batch met the definition of renewable biomass.

(xiii) Whether appropriate RIN generation and verified batch volume calculations under this part were followed for each verified batch.

(xiv) The quantity and type of co-products produced.

(xv) Invoice document identification numbers associated with each verified batch.

(xvi) Laboratory sample identification numbers for each verified batch associated with the generation of any certificates of analysis used to verify fuel type and quality.

(xvii) Any additional information that EPA may require.

(2) The following aggregate verification information, as applicable:

* * * * *

(vii) A list of all audited facilities, including the EPA's company and facility registration numbers, along with the date the independent third-party auditor conducted the on-site visit and audit.

(viii) Mass and energy balances calculated for each audited facility.

(ix) A list of all RINs that were identified as Potentially Invalid RINs (PIRs) pursuant to §§ 80.185 and 80.1474, along with a narrative description of why the RINs were not verified or were identified as PIRs.

(x) A list of all biointermediates that were identified as potentially improperly produced biointermediates under § 80.1477(d).

(xi) A list of all biogas that was identified as potentially inaccurate or non-qualifying under § 80.185(b).

(xii) Any additional information that EPA may require.

* * * * *

**§ 80.1452 [Amended]**

■ 32. Amend § 80.1452 by:

■ a. In paragraph (b)(14), removing the text ''as defined in § 80.1401'';

■ b. In paragraph (b)(18), removing the text ''the Administrator'' and adding in its place the text ''that EPA''; and

■ c. In paragraphs (c)(14) and (d), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

■ 33. Amend § 80.1453 by:

■ a. Revising paragraphs (a) introductory text, (a)(12) introductory text, and (a)(12)(v);

■ b. Adding paragraph (a)(12)(viii);

■ c. In paragraphs (d) and (f)(1)(vi), removing the text ''§ 80.1401'' and adding in its place the text ''§ 80.2''; and

■ d. Adding paragraph (f)(1)(vii).

The revisions and additions read as follows:

**§ 80.1453 What are the product transfer document (PTD) requirements for the RFS program?**

(a) On each occasion when any party transfers ownership of neat or blended renewable fuels or RNG, except when such fuel is dispensed into motor vehicles or nonroad vehicles, engines, or equipment, or separated RINs subject to this subpart, the transferor must provide to the transferee documents that include all the following information, as applicable:

* * * * *

(12) For the transfer of renewable fuel or RNG for which RINs were generated, an accurate and clear statement on the product transfer document of the fuel type from the approved pathway, and designation of the fuel use(s) intended by the transferor, as follows:

* * * * *

(v) Naphtha. ''This volume of neat or blended naphtha is designated and intended for use as transportation fuel or jet fuel in the 48 U.S. contiguous states and Hawaii. This naphtha may only be used as a gasoline blendstock, E85 blendstock, or jet fuel. Any person exporting this fuel is subject to the requirements of 40 CFR 80.1430.''.

* * * * *

(viii) RNG. ''This volume of RNG is designated and intended for transportation use in the 48 U.S. contiguous states and Hawaii or as a feedstock to produce a renewable fuel and may not be used for any other purpose. Any person exporting this fuel is subject to the requirements of 40 CFR 80.1430. Assigned RINs to this volume of RNG must not be separated unless the RNG is used as transportation fuel in the 48 U.S. contiguous states and Hawaii.''

* * * * *

(f) * * *

(1) * * *

(vii) For biogas designated for use as a biointermediate, any applicable PTD requirements under § 80.150.

* * * * *

■ 34. Amend § 80.1454 by:

■ a. In paragraph (a) introductory text, removing the text ''(as described at § 80.1406)'' and ''(as described at § 80.1430)'';

■ b. In paragraph (b) introductory text, removing the text ''as defined in § 80.1401'';

■ c. Revising paragraphs (b)(3)(ix) and (xii);

■ d. In paragraph (b)(8), removing the text ''§ 80.1401'' and adding in its place the text ''§ 80.2'';

■ e. In paragraph (c)(1) introductory text, removing the text ''(as defined in § 80.1401)'';

■ f. In paragraph (c)(1)(iii), removing the text ''as defined in § 80.1401'';

■ g. In paragraph (c)(2) introductory text, removing the text ''(as defined in § 80.1401)'';

■ h. Adding paragraphs (c)(2)(vii) and (c)(3);

■ i. Removing paragraph (d) introductory text;

■ j. Redesignating paragraphs (d)(1) through (4) as paragraphs (d)(2) through (5), respectively, and adding a new paragraph (d)(1);

■ k. In newly redesignated paragraph (d)(2)(ii), removing the text ''(d)(1)(i)'' and adding in its place the text ''(d)(2)(i)'';

■ l. In newly redesignated paragraph (d)(4)(ii)(B), removing the text ''(d)(3)(ii)(A)'' and adding in its place the text ''(d)(4)(ii)(A)'';

■ m. Revising newly redesignated paragraph (d)(5);

■ n. Adding paragraph (d)(6);

■ o. In paragraphs (h)(3)(iv) and (v), removing the text ''as defined in § 80.1401'';

■ p. Removing paragraphs (h)(6)(vi) and (vii);

■ q. Revising paragraph (j) introductory text;

■ r. In paragraphs (j)(1)(iii), (j)(2)(iv), and (k)(1)(vii), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ s. Revising paragraphs (k)(2) and (l) introductory text;

■ t. In paragraphs (l)(4) and (m)(11), removing the text ''the Administrator'' and adding in its place the text ''EPA'';

■ u. In paragraph (t), removing the text ''the Administrator or the Administrator's authorized representative'' and adding in its place the text ''EPA''; and

■ v. In paragraph (v), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

The revisions and additions read as follows:

**§ 80.1454 What are the recordkeeping requirements under the RFS program?**

* * * * *

(b) * * *

(3) * * *

(ix) All facility-determined values used in the calculations under § 80.1426(f)(4) and the data used to obtain those values.

* * * * *

(xii) For RINs generated for ethanol produced from corn starch at a facility using an approved pathway that requires the use of one or more of the advanced technologies listed in Table 2 to § 80.1426, documentation to demonstrate that employment of the required advanced technology or technologies was conducted in accordance with the specifications in the approved pathway and Table 2 to § 80.1426, including any requirement for application to 90% of the production on a calendar year basis.

* * * * *

(c) * * *

(2) * * *

(vii) For renewable fuel or biointermediate produced from a type of renewable biomass not specified in paragraphs (c)(1)(i) through (vi) of this section, documents from their feedstock suppliers and feedstock aggregators, as applicable, certifying that the feedstock qualifies as renewable biomass, describing the feedstock.

(3) Producers of renewable fuel or biointermediate produced from separated yard and food waste, biogenic oils/fats/greases, or separated MSW must comply with either the recordkeeping requirements in paragraph (j) of this section or the alternative recordkeeping requirements in § 80.1479.

(d) *Additional requirements for domestic producers of renewable fuel.* (1) Except as provided in paragraphs (g) and (h) of this section, any domestic producer of renewable fuel that generates RINs for such fuel must 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 if RINs are generated.

* * * * *

(5) Domestic producers of renewable fuel or biointermediates produced from a type of renewable biomass not specified in paragraphs (d)(2) through (4) of this section must have documents from their feedstock suppliers and feedstock aggregators, as applicable, certifying that the feedstock qualifies as renewable biomass, describing the feedstock.

(6) Producers of renewable fuel or biointermediate produced from separated yard and food waste, biogenic oils/fats/greases, or separated MSW must comply with either the recordkeeping requirements in paragraph (j) of this section or the alternative recordkeeping requirements in § 80.1479.

* * * * *

(j) *Additional requirements for producers that use separated yard waste, separate food waste, separated MSW, or biogenic waste oils/fats/greases.* Except for parties complying with the alternative recordkeeping requirements in § 80.1479, a renewable fuel or biointermediate producer that produces fuel or biointermediate from separated yard waste, separated food waste, separated MSW, or biogenic waste oils/fats/greases must keep all the following additional records:

* * * * *

(k) * * *

(2) *Biogas and electricity in pathways involving grain sorghum as feedstock.* A renewable fuel producer that produces fuel pursuant to a pathway that uses grain sorghum as a feedstock must keep all the following additional records, as appropriate:

(i) Contracts and documents memorializing the purchase and sale of biogas and the transfer of biogas from the point of generation to the ethanol production facility.

(ii) If the advanced biofuel pathway is used, documents demonstrating the total kilowatt-hours (kWh) of electricity used from the grid, and the total kWh of grid electricity used on a per gallon of ethanol basis, pursuant to § 80.1426(f)(13).

(iii) Affidavits from the biogas producer used at the facility, and all parties that held title to the biogas, confirming that title and environmental attributes of the biogas relied upon under § 80.1426(f)(13) were used for producing ethanol at the renewable fuel production facility and for no other purpose. The renewable fuel producer must obtain these affidavits for each quarter.

(iv) The biogas producer's Compliance Certification required under Title V of the Clean Air Act.

(v) Such other records as may be requested by EPA.

(l) *Additional requirements for producers or importers of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable diesel, biogas-derived renewable fuel, or renewable electricity.* A renewable fuel producer that generates RINs for any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable diesel that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.12), biogas-derived renewable fuel or renewable electricity must keep all the following additional records:

* * * * *

**§ 80.1455 [Removed and Reserved]**

■ 35. Remove and reserve § 80.1455.

**§ 80.1457 [Amended]**

■ 36. Amend § 80.1457 by, in paragraph (b)(8), removing the text ''the Administrator'' and adding in its place the text ''that EPA''.

37. Add § 80.1458 to read as follows:

**§ 80.1458 Storage of renewable fuel, RNG, or biointermediate prior to registration.**

(a) *Applicability.* (1) A renewable fuel producer may store renewable fuel for the generation of RINs prior to EPA acceptance of their registration under § 80.1450(b) if all the requirements of this section are met.

(2) An RNG producer may store RNG prior to EPA acceptance of their registration under § 80.135 if all the requirements of this section are met.

(3) A biointermediate producer may store biointermediate (including biogas used to produce a biogas-derived renewable fuel) prior to EPA acceptance of their registration under § 80.1450(b) if all the requirements of this section are met.

(b) *Storage requirements.* In order for a renewable fuel, RNG, or biointermediate producer to store renewable fuel, RNG, or biointermediate under this section, the producer must do the following:

(1) Produce the stored renewable fuel, RNG, or biointermediate after an independent third-party engineer has conducted an engineering review for the renewable fuel, RNG, or biointermediate production facility under § 80.1450(b)(2).

(2) Produce the stored renewable fuel, RNG, or biointermediate in accordance with all applicable requirements under this part.

(3) Make no change to the facility after the independent third-party engineer completed the engineering review.

(4) Store the renewable fuel, RNG, or biointermediate at the facility that produced the renewable fuel, RNG, or biointermediate.

(5) Maintain custody and title to the stored renewable fuel, RNG, or biointermediate until EPA accepts the

producer's registration under § 80.1450(b).

(c) *RIN generation.* (1) A RIN generator may only generate RINs for stored renewable fuel, stored RNG, or renewable fuel produced from stored biointermediate if the RIN generator generates the RINs under §§ 80.125, 80.1426, and 80.1452, as applicable, after EPA accepts their registration under § 80.1450(b) and meets all other applicable requirements under this part for RIN generation.

(2) The RIN year of any RINs generated for stored renewable fuel, stored RNG, or renewable fuel produced from stored biointermediate is the year that the renewable fuel or RNG was produced.

(d) *Limitations.* RNG injected into a natural gas commercial pipeline system prior to EPA acceptance of a renewable fuel producer's registration under § 80.135 does not meet the requirements of this section and may not be stored.

■ 38. Amend § 80.1460 by:

■ a. In paragraph (a), removing the text ''Except as provided in § 80.1455, no'' and adding in its place the text ''No'';

■ b. In paragraphs (c)(2) and (3), removing the text ''(as defined in § 80.1401)'';

■ c. In paragraph (d), removing the text ''§ 80.1428(a)(5)'' and adding in its place the text ''§ 80.1428(a)(4)''

■ d. In paragraph (g), removing the text ''§ 80.1401'' and adding in its place the text ''§ 80.2''; and

■ e. Adding paragraph (l).

The addition reads as follows:

### § 80.1460 What acts are prohibited under the RFS program?

* * * * *

(l) *Independent third-party engineer violations.* No person shall do any of the following:

(1) Fail to identify any incorrect information submitted by any party as specified in § 80.1450(b)(2).

(2) Fail to meet any requirement related to engineering reviews as specified in § 80.1450(b)(2).

(3) Fail to disclose to EPA any financial, professional, business, or other interests with parties for whom the independent third-party engineer provides services under § 80.1450.

(4) Fail to meet any requirement related to the independent third-party engineering review requirements in § 80.1450(b)(2) or (d)(1).

■ 39. Amend § 80.1461 by adding paragraph (f) to read as follows:

### § 80.1461 Who is liable for violations under the RFS program?

* * * * *

(f) *Third-party liability.* Any party allowed under this subpart to conduct sampling and testing on behalf of a regulated party and does so to demonstrate compliance with the requirements of this subpart must meet those requirements in the same way that the regulated party must meet those requirements. The regulated party and the third party are both liable for any violations arising from the third party's failure to meet the requirements of this subpart.

### § 80.1464 [Amended]

■ 40. Amend § 80.1464 by:

■ a. In the introductory text, removing the reference ''§§ 80.1465 and 80.1466'' and adding in its place the reference ''§ 80.1466'';

■ b. In paragraph (a) introductory text, removing the text ''(as described at § 80.1406(a))'' and ''(as described at § 80.1430)'';

■ c. In paragraph (b)(1)(iii), removing the text ''a pathway in Table 1 to § 80.1426'' and adding in its place the text ''an approved pathway'';

■ d. In paragraph (b)(1)(v)(B), removing the text ''in § 80.1401''; and

■ e. In paragraphs (i)(1) and (2), removing the text ''RIN and biointermediate''.

■ 41. Effective April 1, 2024, amend § 80.1466 by:

■ a. In paragraph (d)(2)(ii), removing the text ''The Administrator'' and adding in its place the text ''EPA'';

■ b. In paragraph (f)(1)(viii), removing the text ''working'' and adding in its place the text ''business'';

■ c. Revising paragraphs (h)(1) and (2);

■ d. In paragraph (k)(4)(i), removing the text ''The Administrator'' and adding in its place the text ''EPA'';

■ e. In paragraph (o)(1), removing the text ''the Administrator'' wherever it appears and adding in its place the text ''EPA''; and

■ f. In paragraph (o)(2)(ii), removing the text ''40 CFR 80.1465'' and adding in its place the text ''40 CFR 80.1466''.

The revisions read as follows:

### § 80.1466 What are the additional requirements under this subpart for foreign renewable fuel producers and importers of renewable fuels?

* * * * *

(h) * * *

(1) The RIN-generating foreign producer must post a bond of the amount calculated using the following equation.

Bond = G * $0.22

Where:

Bond = Amount of the bond in U.S. dollars.

G = The greater of: (1) The largest volume of renewable fuel produced by the RIN-generating foreign producer and exported to the United States, in gallons, during a single calendar year among the five preceding calendar years; or (2) The largest volume of renewable fuel that the RIN-generating foreign producers expects to export to the United States during any calendar year identified in the Production Outlook Report required by § 80.1449. If the volume of renewable fuel exported to the United States increases above the largest volume identified in the Production Outlook Report during any calendar year, the RIN-generating foreign producer must increase the bond to cover the shortfall within 90 days.

(2) Bonds must be obtained in the proper amount from a third-party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign producer, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

* * * * *

■ 42. Effective April 1, 2024, amend § 80.1467 by:

■ a. In paragraph (c)(1)(viii), removing the text ''working'' and adding in its place the text ''business'';

■ b. Revising paragraphs (e)(1) and (2); and

■ c. In paragraph (j)(1), removing the text ''the Administrator'' wherever it appears and adding in its place the text ''EPA''.

The revisions read as follows:

### § 80.1467 What are the additional requirements under this subpart for a foreign RIN owner?

* * * * *

(e) * * *

(1) The foreign entity must post a bond of the amount calculated using the following equation:

Bond = G * $ 0.22

Where:

Bond = Amount of the bond in U.S. dollars.

G = The total of the number of gallon-RINs the foreign entity expects to obtain, sell, transfer, or hold during the first calendar year that the foreign entity is a RIN owner, plus the number of gallon-RINs the foreign entity expects to obtain, sell, transfer, or hold during the next four calendar years. After the first calendar year, the bond amount must be based on the actual number of gallon-RINs obtained, sold, or transferred so far during the current calendar year plus the number of gallon-RINs obtained, sold, or transferred during the four calendar years immediately preceding the current calendar year. For any year for which there were fewer than four preceding years in which the foreign entity obtained, sold, or transferred RINs, the bond must be based on the total of the number of gallon-RINs sold or transferred so far during the current calendar year plus the number of gallon-RINs obtained, sold, or transferred during any immediately preceding calendar years in which the foreign entity owned RINs, plus the number of gallon-RINs the foreign entity expects to obtain, sell or transfer during subsequent calendar years, the total number of years not to exceed four calendar years in addition to the current calendar year.

(2) Bonds must be obtained in the proper amount from a third-party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign RIN owner, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

* * * * *

**§ 80.1468 [Removed and Reserved]**

■ 43. Remove and reserve § 80.1468.

■ 44. Amend § 80.1469 by:

■ a. In paragraph (a)(1)(i)(A), removing the text ''as defined in § 80.1401'';

■ b. In paragraphs (a)(1)(i)(F) and (a)(2)(i)(B), removing the text ''as permitted under Table 1 to § 80.1426 or a petition approved through § 80.1416'' and adding in its place the text ''from the approved pathway'';

■ c. In paragraph (a)(3)(i)(F), removing the text ''EV'' and adding in its place the text ''EqV'';

■ d. In paragraph (b)(1)(i), removing the text ''as defined in § 80.1401'';

■ e. In paragraphs (b)(1)(vi) and (b)(2)(ii), removing the text ''as permitted under Table 1 to § 80.1426 or a petition approved through § 80.1416'' and adding in its place the text ''from the approved pathway'';

■ f. In paragraph (b)(3)(v), removing the text ''EV'' and adding in its place the text ''EqV'';

■ g. In paragraph (c)(1)(i), removing the text ''as defined in § 80.1401'';

■ h. In paragraph (c)(3)(v), removing the text ''EV'' and adding in its place the text ''EqV'';

■ i. Revising paragraph (c)(4) paragraph heading;

■ j. In paragraph (c)(4)(i), removing the text ''§ 80.1429(b)(4)'' and adding in its place the text ''§ 80.1429(b)'';

■ k. Adding paragraph (c)(6);

■ l. Revising paragraph (d); and

■ m. In paragraph (e)(1), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

The revisions and addition read as follows:

**§ 80.1469 Requirements for Quality Assurance Plans.**

* * * * *

(c) * * *

(4) *Other RIN-related components.* * * *

* * * * *

(6) *Documentation.* Independent third-party auditors must review all relevant registration information under § 80.1450, reporting information under § 80.1451, and recordkeeping information under § 80.1454, as well as any other relevant information and documentation required under this part, to verify elements in a QAP approved by EPA under this section.

(d) In addition to a general QAP encompassing elements common to all pathways, for each QAP there must be at least one pathway-specific plan for an approved pathway, which must contain elements specific to particular feedstocks, production processes, and fuel types, as applicable.

* * * * *

■ 45. Amend § 80.1471 by:

■ a. Revising paragraphs (b) introductory text and (b)(1);

■ b. In paragraph (b)(2), removing the text ''as defined in § 80.1406'';

■ c. Revising paragraphs (b)(4) through (6); and

■ d. Adding paragraphs (b)(8) through (12).

The revisions and additions read as follows:

**§ 80.1471 Requirements for QAP auditors.**

* * * * *

(b) To be considered an independent third-party auditor under paragraph (a) of this section, all the following conditions must be met:

(1) The independent third-party auditor and its contractors and subcontractors must not be owned or operated by the audited party or any subsidiary or employee of the audited party.

* * * * *

(4) The independent third-party auditor and its contractors and subcontractors must be free from any interest or the appearance of any interest in the audited party's business.

(5) The audited party must be free from any interest or the appearance of any interest in the third-party auditor's business and the businesses of third-party auditor's contractors and subcontractors.

(6) The independent third-party auditor and its contractors and subcontractors must not have performed an attest engagement under § 80.1464(b) for the audited party for the same compliance period as a QAP audit conducted pursuant to § 80.1472.

* * * * *

(8) The independent third-party auditor and its contractors and subcontractors must act impartially when performing all activities under this section.

(9) The independent third-party auditor and its contractors and subcontractors must be free from any interest in the audited party's business and receive no financial benefit from the outcome of auditing service, apart from payment for the auditing services.

(10) The independent third-party auditor and its contractors and subcontractors must not have been involved in the design or construction of the audited facility.

(11) The independent third-party auditor and its contractors and subcontractors must ensure that all personnel involved in the third-party audit (including the verification activities) under this section are not negotiating for future employment with the owner or operator of the audited party. At a minimum, prior to conducting the audit, the independent third-party auditor must obtain an attestation (or similar document) from each person involved in the audit stating that they are not negotiating for future employment with the owner or operator of the audited party.

(12) The independent third-party auditor and its contractors and subcontractors must have written policies and procedures to ensure that the independent third-party auditor and all personnel under the independent third-party auditor's direction or supervision comply with the competency, independence, and impartiality requirements of this section.

* * * * *

**§ 80.1473 [Amended]**

■ 46. Amend § 80.1473 by, in paragraphs (c)(1), (d)(1), and (e)(1), removing the text ''defined'' and adding in its place the text ''specified''.

**§ 80.1474 [Amended]**

■ 47. Amend § 80.1474 by, in paragraph (g), removing the text ''the Administrator'' and adding in its place the text ''EPA''.

**§ 80.1478 [Amended]**

■ 48. Amend § 80.1478 by, in paragraph (g)(1), removing the text ''the Administrator'' wherever it appears and adding in its place the text ''EPA''.

■ 49. Add § 80.1479 to read as follows:

**§ 80.1479 Alternative recordkeeping requirements for separated yard waste, separated food waste, separated MSW, and biogenic waste oils/fats/greases.**

(a) *Alternative recordkeeping.* In lieu of complying with the recordkeeping requirements in § 80.1454(j), a renewable fuel producer or biointermediate producer that produces renewable fuel or biointermediate from separated yard waste, separated food waste, separated MSW, or biogenic waste oils/fats/greases and uses a feedstock aggregator to supply these feedstocks may comply with the alternative recordkeeping requirements of this section.

(b) *Registration of the feedstock aggregator.* The feedstock aggregator must register under 40 CFR 1090.805.

(c) *QAP participation.* (1) The renewable fuel or biointermediate producer must have their RINs or biointermediate, as applicable, verified by an independent third-party auditor under an approved QAP that includes a description of how the independent third-party auditor will audit each feedstock aggregator.

(2) The independent third-party auditor must conduct a site visit of each feedstock aggregator's establishment as specified in § 80.1471(f). Instead of verifying RINs with a site visit of the feedstock aggregator's establishment every 200 days as specified in § 80.1471(f)(1)(ii), the independent third-party auditor may verify RINs with a site visit every 380 days.

(d) *PTDs.* PTDs must accompany transfers of separated yard waste, separated food waste, separated MSW, and biogenic waste oils/fats/greases from the point where the feedstock leaves the feedstock aggregator's establishment to the point the feedstock is delivered to the renewable fuel production facility, as specified in § 80.1453(f)(1)(i) through (v).

(e) *Recordkeeping.* The feedstock aggregator 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 § 80.1454(j).

(f) *Liability.* The feedstock aggregator and renewable fuel producer are liable for violations as specified in § 80.1461(e).

## PART 1090—REGULATION OF FUELS, FUEL ADDITIVES, AND REGULATED BLENDSTOCKS

■ 50. The authority citation for part 1090 continues to read as follows:

**Authority:** 42 U.S.C. 7414, 7521, 7522–7525, 7541, 7542, 7543, 7545, 7547, 7550, and 7601.

### Subpart A—General Provisions

■ 51. Amend § 1090.55 by revising paragraph (c) to read as follows:

#### § 1090.55 Requirements for independent parties.

* * * * *

(c) *Suspension and disbarment.* Any person suspended or disbarred under 2 CFR part 1532 or 48 CFR part 9, subpart 9.4, is not qualified to perform review functions under this part.

■ 52. Amend § 1090.80 by:

■ a. In the definition for ''PADD'', revising entry ''II'' in the table; and

■ b. In the definition of ''Ultra low-sulfur diesel (ULSD)'', removing the text ''Ultra low-sulfur diesel (ULSD)'' and adding in its place the text ''Ultra-low-sulfur diesel (ULSD)''.

The revision reads as follows:

#### § 1090.80 Definitions.

* * * * *

*PADD* * * *

| PADD | Regional description | State or territory |
|---|---|---|
| * | * | * * * * * |
| II | Midwest | Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, Wisconsin |
| * | * | * * * * * |

* * * * *

### Subpart I—Registration

■ 53. Amend § 1090.805 by revising paragraph (a)(1)(iv) to read as follows:

#### § 1090.805 Contents of registration.

(a) * * *

(1) * * *

(iv) Name(s), title(s), telephone number(s), and email address(es) of an RCO and their delegate, if applicable.

* * * * *

### Subpart S—Attestation Engagements

#### § 1090.1830 [Amended]

■ 54. Amend § 1090.1830 by, in paragraph (a)(3), adding the text ''all'' after the text ''submitted''.

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