ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 80 and 1090

[EPA–HQ–OAR–2021–0427; FRL–8514–01–OAR]

RIN 2060–AV14

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed 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 proposes 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 proposes the second supplemental standard addressing the remand of the 2016 standard-setting rulemaking. Finally, this action proposes several regulatory changes to the RFS program including regulations governing the generation of qualifying renewable electricity and other modifications intended to improve the program's implementation.

DATES:

Comments. Comments must be received on or before February 10, 2023.

Public Hearing. EPA will announce information regarding the public hearing for this proposal in a supplemental **Federal Register** document.

ADDRESSES:

Comments. You may send your comments, identified by Docket ID No. EPA–HQ–OAR–2021–0427, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Email: a-and-r-Docket@epa.gov.* Include Docket ID No. EPA–HQ–OAR–2021–0427 in the subject line of the message.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Air Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand Delivery or Courier:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operation are 8:30 a.m.–4:30 p.m., Monday–Friday (except Federal Holidays).

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: David Korotney, Office of Transportation and Air Quality, Assessment and Standards Division, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; telephone number: 734–214–4507; email address: *RFS-Rulemakings@epa.gov.* Comments on this proposal should not be submitted to this email address, but rather through *http://www.regulations.gov* as discussed in the **ADDRESSES** section.

SUPPLEMENTARY INFORMATION: Entities potentially affected by this proposed 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, biogas, and renewable electricity), and electric vehicles. 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	221117	Biomass electric power generation.
Industry	221210	Manufactured gas production and distribution, and distribution of renewable natural gas (RNG).
Industry	221320	Sewage treatment plants or facilities.
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	336110	Electric automobiles for highway use 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 likely to be affected by this proposed action. This table lists the types of entities that EPA is now aware could potentially be affected by this proposed action. Other types of entities not listed in the table could also be affected. To determine whether your entity would be affected by this proposed action, you should carefully examine the applicability criteria in 40 CFR part 80. If you have any questions regarding the applicability of this proposed action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Outline of This Preamble

I. Executive Summary
A. Summary of the Key Provisions of This Regulatory Action
B. Environmental Justice
C. Comparison of Costs to Impacts
D. Policy Considerations
E. Endangered Species Act
II. Statutory Requirements and Conditions
A. Requirement To Set Volumes for Years After 2022
B. Factors That Must Be Analyzed
C. Statutory Conditions on Volume Requirements
D. Authority To Establish Percentage Standards for Multiple Future Years
E. Considerations for Late Rulemaking
F. Impact on Other Waiver Authorities
G. Severability
III. Candidate Volumes and Baselines

A. Number of Years Analyzed
B. Production and Import of Renewable Fuel
C. Candidate Volumes for 2023–2025
D. Baselines
E. Volume Changes Analyzed
IV. Analysis of Candidate Volumes
A. Climate Change
B. Energy Security
C. Costs
D. Comparison of Costs and Impacts
E. Assessment of Environmental Justice
V. Response to Remand of 2016 Rulemaking
A. Supplemental 2023 Standard
B. Authority and Consideration of the Benefits and Burdens
VI. Proposed Volume Requirements for 2023–2025
A. Cellulosic Biofuel
B. Non-Cellulosic Advanced Biofuel
C. Biomass-Based Diesel
D. Conventional Renewable Fuel
E. Summary of Proposed Volume Requirements
F. Request for Comment on Volume Requirements for 2026
G. Request for Comment on Alternative Volume Requirements
VII. Proposed Percentage Standards for 2023–2025
A. Calculation of Percentage Standards
B. Treatment of Small Refinery Volumes
C. Proposed Percentage Standards
VIII. Regulatory Program for Renewable Electricity
A. Historical Treatment of Electricity in the RFS Program
B. The eRIN Generation and Disposition Chain
C. Policy Goals in Developing the eRIN Program
D. Regulatory Goals in Developing the eRIN Program
E. Proposed Applicability of the eRIN Program
F. Proposed Program Structure for Light-Duty Vehicles
G. How the Proposed Program Structure Meets the Goals
H. Alternative eRIN Program Structures
I. Equivalence Value for Electricity
J. Regulatory Structure and Implementation Dates
K. Definitions
L. Registration, Reporting, Product Transfer Documents, and Recordkeeping
M. Testing and Measurement Requirements
N. RFS Quality Assurance Program (QAP)
O. Compliance and Enforcement Provisions and Attest Engagements
P. Foreign Producers
IX. Other Changes to Regulations
A. RFS Third-Party Oversight Enhancement
B. Deadline for Third-Party Engineering Reviews for Three-Year Updates
C. RIN Apportionment in Anaerobic Digesters
D. BBD Conversion Factor for Percentage Standard
E. Flexibility for RIN Generation
F. Changes to Tables in 40 CFR 80.1426
G. Prohibition on RIN Generation for Fuels Not Used in the Covered Location
H. Seeking Public Comment on Hydrogen Fuel Lifecycle Analysis
I. Biogas Regulatory Reform
J. Separated Food Waste Recordkeeping Requirements
K. Definition of Ocean-Going Vessels
L. Bond Requirement for Foreign RIN-Generating Renewable Fuel Producers
M. Definition of Produced From Renewable Biomass
N. Limiting RIN Separation Amounts
O. Technical Amendments
X. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA) & Incorporation by Reference
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations, and Low-Income Populations
XI. Statutory Authority

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 proposes the volume targets and applicable percentage standards for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel for 2023–2025. In association with these volume targets, we are also proposing new regulations governing the generation of Renewable Identification Numbers (RINs) for electricity made from renewable biomass that is used for transportation fuel, as well as a number of other regulatory changes intended to improve the operation of the RFS program.

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,

[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.

production, and use of low-carbon, domestically produced renewable fuels. This ''Set rule'' proposal 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 their input on what policy direction this action should take, and the Agency greatly appreciates the sustained and constructive input we have received from stakeholders. The RFS program is entering a new phase, and we are introducing a new regulatory program governing renewable electricity. We welcome comments not only on the volumes we are proposing in this rule but also on the analyses we conducted and the proposed regulatory changes. EPA looks forward to continued engagement with stakeholders on this rule, through the formal public comment process, the public hearing we will hold, and through meetings with program participants and others.

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 propose to establish the volume targets for three years, 2023 to 2025, as shown below. In addition to the volume targets, we are also proposing to complete our response to the D.C. Circuit Court of Appeals' remand of the 2016 annual rule in *Americans for Clean Energy* v. *EPA,* 864 F.3d 691 (2017) (hereafter ''*ACE*'') by proposing 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—PROPOSED VOLUME TARGETS

[Billion RINs] [a]

	2023	2024	2025
Cellulosic biofuel	0.72	1.42	2.13
Biomass-based diesel [b]	2.82	2.89	2.95
Advanced biofuel	5.82	6.62	7.43
Renewable fuel	20.82	21.87	22.68
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 and electricity (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 to establish. However, many of those factors, particularly those related to economic and environmental impacts, would be 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 propose. 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 to identify ''candidate volumes'' that we then subjected to the other economic and environmental factors that we are required to analyze. 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 propose in light of all of the analyses that we conducted.

We believe that proposing volume targets for more than one year is appropriate as it will provide the market with the certainty of demand needed for longer term business and investment plans. At the same time, setting volume targets too far out into the future can be difficult given the higher uncertainty associated with projecting supply for longer time periods and the increasing likelihood for unforeseen circumstances to upset supply. By proposing volume requirements for three years in this action but leaving the development of volume requirements for 2026 and beyond to a subsequent action, we believe we are striking a reasonable balance between certainty in our projections and providing certainty for investment. Nevertheless, recognizing that many regulated parties would appreciate knowing the applicable standards for as many years as is reasonably possible, we are requesting comment on establishing standards for 2026 in addition to 2023–2025 through this rulemaking.

The volume targets that we are proposing in this action would have the same status as those in the statute for the years shown in Table I–1. That is, they would be 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

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.[9] For years after 2022, EPA can establish percentage standards for any number of years at the same time that it establishes the volume targets for those years. As this proposed rule is being released in 2022, we are proposing the applicable percentage standards for 2023 in this action. In addition, we are proposing the percentage standards for the two other years (2024 and 2025) for which we are proposing volume requirements, the merits of which we discuss in Section II.D. The proposed percentage standards corresponding to the proposed volume requirements from Table I.A.1–1 are shown below.

[8] 87 FR 39600 (July 1, 2022).

[9] CAA section 211(o)(3).

TABLE I.A.2–1—PROPOSED PERCENTAGE STANDARDS

	2023	2024	2025
Cellulosic biofuel	0.41	0.82	1.23
Biomass-based diesel	2.54	2.60	2.67
Advanced biofuel	3.33	3.80	4.28
Renewable fuel	11.92	12.55	13.05
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. For this proposed rulemaking we have projected that based on the information available at the present time there are not likely to be small refinery exemptions (SREs) for 2023–2025. 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 would be added to the regulations at 40 CFR 80.1405(a).

3. Regulatory Provisions for eRINs

We are proposing regulatory changes to prescribe how RINs from renewable electricity (eRINs) would be implemented and managed under the RFS program. These changes are intended to address many of the outstanding issues which to date have prevented EPA from registering parties to allow them to generate eRINs produced from qualifying renewable biomass and used as transportation fuel. The regulations we propose as part of this action address a number of important areas, including which parties can generate eRINs, prevention of double-counting, and data requirements for valid eRIN generation. The proposed changes are intended to provide clarity on how electricity would be incorporated into the RFS so that the existing RIN-generating pathway can be effectively utilized in a manner that ensures RINs are generated only for qualifying electricity. We recognize that multiple stakeholders have expressed interest in the design of the regulations governing the generation of eRINs, and while this action proposes regulations to implement one chosen approach, this package also describes alternative approaches. We welcome comments on both the proposed and alternative approaches.

In addition to the general program requirements for eRINs we are also proposing to revise the equivalence value for renewable electricity in the RFS program under 40 CFR 80.1415. The current value of 22.6 kWh/RIN would be replaced by a value of 6.5 kWh/RIN. We believe that this change would more accurately represent the use of electricity as a transportation fuel relative to the production of biogas.

Given the timing of this rulemaking and the need for sufficient time for regulated parties to become familiar with the new eRIN regulatory requirements and to register for eRIN generation, we propose that those requirements would become effective beginning on January 1, 2024. To this end, the proposed cellulosic volume requirements shown in Table I.A.1–1 include our projected volumes for eRINs for years 2024 and 2025, but does not include any projection for eRINs for 2023.

4. Other Regulatory Changes

We have identified several areas where regulatory changes would assist EPA in implementing the RFS program. These proposed regulatory changes include:

- 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;
- Amending the provisions for the generation of RINs for straight vegetable oil to ensure that RINs are valid;
- Clarifying the definition of fuel used in ocean-going vessels; and
- Other minor changes and technical corrections

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

5. Request for Comment on Alternative Volume Requirements

We are requesting comment on various alternative approaches that we could take with respect to volumes as well as certain other policy parameters. Specifically, we request comment on whether we should establish volume requirements for one or two years instead of three years, whether the implied conventional renewable fuel volume requirement should be 15.00 billion gallons rather than 15.25 billion gallons in 2024 and 2025, or whether the implied conventional renewable fuel volume requirement should be reduced by some other amount, such as below the E10 blendwall, while keeping the total renewable fuel volume requirement unchanged. Section VI.G provides additional discussion of these alternatives.

B. Environmental Justice

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. It directs federal agencies, to the greatest extent practicable and permitted by law, to make achieving 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.

This proposed 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.[10] [11] The

[10] 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,

Continued

manner in which the market responds to the provisions in this proposed rule could also have non-GHG impacts. For instance, replacing petroleum fuels with renewable fuels will also have impacts on water and air exposure for communities living near biofuel and petroleum facilities given the potential for biofuel facilities to have relatively high emission rates in local communities. 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. Our assessment of potential economic impacts on people of color and low-income populations is provided in Section IV.E.3.

C. Comparison of Costs to Impacts

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 draft Regulatory Impact Analysis (DRIA) accompanying this proposed rule. However, the statute does not specify how EPA must assess each factor. For two of these statutory factors, costs and energy security impacts, 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 cannot be easily monetized for comparison. Thus, we are unable to quantitatively compare all of the evaluated impacts when assessing the overall costs and impacts of this proposed rulemaking. We request comment generally on how costs and benefits quantified in this proposed rule are calculated and accounted for, methods to quantify and monetize additional statutory factors, and appropriate means of comparing the costs and benefits. Table ES–1 in the DRIA provides a list of all of the impacts that we assessed, both quantitative and qualitative. Our assessments of each factor, including the different components of the estimated costs, energy security methodology, climate impacts, and other environmental and economic impacts, are summarized in Section IV of this document. Additional detail for each of the assessed factors is provided in DRIA Chapters 4 through 10.

Monetized cost and energy security impacts are summarized in Table I.C–1 below using two discount rates (3 percent and 7 percent) following federal guidance on regulatory impact analyses.[12] 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.

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

[2021$, millions]

	Discount rate	
	3%	7%
Excluding Supplemental Standard:		
Cost Impacts	28,801	27,835
Energy Security Benefits	623	600
Including Supplemental Standard:		
Cost Impacts	29,458	28,492
Energy Security Benefits	634	611

D. Policy Considerations

This proposed rule comes at a time when major policy developments and global events are affecting the transportation energy and environmental landscape in unprecedented ways. The recently passed 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 a policy imperative. The war in Ukraine has significantly destabilized multiple global commodity markets, including petroleum markets. 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 proposing to establish volume requirements under the RFS program, through the ''Set'' rule process, for the next three years. The volumes that EPA is proposing sustain a path of renewable fuel growth for the program and build on the foundation set by the 2022

T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[11] 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.*

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

required volumes. Beyond providing continued support for fuels like ethanol and biodiesel, the set proposal provides a strong market signal for the continued growth of low carbon advanced biofuels, including ''drop-in'' renewable diesel, cellulosic biofuels, and through a newly proposed program for electricity produced from qualifying renewable feedstocks and used as transportation fuel. Renewable fuels are a key policy tool identified by Congress for decarbonizing the transportation sector, and this rulemaking will set the stage for further growth and development of low-carbon biofuels in the coming years.

With this proposal, EPA is asking for public comment on multiple elements of the rule, including our analysis, volume requirements, and proposed regulatory amendments. Simultaneously, EPA, having heard from a range of stakeholders who have raised concerns and questions reflecting a number of policy considerations that potentially bear on this proposal, is interested in the public's input about how this proposal intersects with the larger energy transition and energy security issues discussed above. EPA is interested, for example, in understanding how the proposed required RFS volume requirements interact with domestic refining capacity and associated energy security considerations. We are also interested in public input regarding ways in which EPA might enhance program administration to make the RFS program as efficient as possible, to increase program transparency, to address climate change, or otherwise improve program implementation.

More specifically, EPA is interested in public and stakeholder input on the questions listed below, which will be considered and may inform the contents of the final rule. We note that for some of these topics, stakeholders may have previously provided information to EPA. We therefore ask that information provided in response to this request focus on new data, new information, or new policy suggestions.

- How can the proposed set rule further Congress' policy goal of enhancing energy security, specifically with respect to the transportation sector?
- How do the requirements of this proposed rule intersect with continued viability of domestic oil refining assets? How does the structure or positioning of refining assets in the marketplace, such as refineries that operate on a merchant basis, relate to a given obligated party's ability to participate, and associated costs with participation, in the RFS program?
- Are there policy changes or additional programmatic incentives that EPA should consider implementing under the RFS program to strengthen or accelerate the transition to a decarbonized transportation sector?
- If EPA were to incorporate some measure of the carbon intensity of each biofuel into the RFS program (*e.g.,* providing a higher RIN value for fuels with a better carbon intensity score), what approach would best advance the program's environmental objectives, and at the same time be consistent with the statutory provisions of CAA section 211(o)?
- How can EPA best build upon the policy investments that the IRA established to further develop low carbon renewable fuels, including through incentives established through the RFS program?
- What role can the RFS program play, beyond what exists today, to further support the development of sustainable aviation fuel?
- Are there steps EPA should consider taking under the RFS program to integrate carbon capture and storage (CCS) opportunities related to the production of renewable fuels?
- Are there steps EPA should consider taking under the RFS program to capture opportunities related to hydrogen derived from renewable biomass?
- What actions should EPA consider to improve the transparency of how the Agency administers the RFS program? Are there steps EPA should consider taking to enhance RIN market liquidity, transparency, and efficiency, or otherwise improve market administration? For example, should EPA revisit some of the policy design conclusions of the 2019 RIN market reform rule such as the RIN holding thresholds that require parties to publicly disclose their positions? [13] Are there other policy designs not considered in that rule that EPA should be considering in this rule?
- As noted earlier, should the conventional renewable fuel volume requirement be set below the E10 blendwall, while keeping the total proposed renewable fuel volume requirement unchanged?

In addition, the inclusion of a new regulatory program for eRINs significantly increases the uncertainty of our cellulosic biofuel projections for 2024 and 2025, and that uncertainty may warrant special consideration. Unlike other types of cellulosic biofuel, EPA has no history projecting the generation of eRINs under the RFS program. The number of eRINs generated could also be impacted by a number of interrelated and complex factors, such as the size and future growth rate of the EV fleet, the supply of qualifying biogas for electricity generation, competition for the biogas and electricity from other markets, and the rate at which electricity generators can register to participate in the RFS program. Our consideration of these factors in projecting eRIN volumes can be found in DRIA Chapter 6.1.4. We request comment on how to account for the uncertainty in projecting the quantity of eRINs in the RFS program, and specifically, whether we should be considering lower (or different) cellulosic volume requirements for 2024 and 2025 in this rule.

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, along 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 agency is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of designated critical habitat for such species. Under relevant implementing regulations, the action agency is required to consult with the Services only for actions that ''may affect'' listed species or designated 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 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 has been engaged in informal consultation including technical assistance discussions with the Services regarding this rule.

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 the Act in Section 211(o)(2).[14] For total

[13] 84 FR 26980 (June 10, 2019).

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

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 biomass-based diesel (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 the statutory authority and additional factors we are considering due to the lateness of this rulemaking, as well as the severability of the various portions of this proposed rule.

B. Factors That Must Be Analyzed

In setting the applicable annual renewable fuel volumes, EPA must comply with the processes, criteria, and standards set forth in CAA section 211(o)(2)(B)(ii). That provision provides that the Administrator shall, in coordination with the Secretary of Energy and the Secretary of Agriculture,[15] 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; [16]
- The impact of renewable fuels on the energy security of the U.S.; [17]
- The expected annual rate of future commercial production of renewable fuels; [18]
- The impact of renewable fuels on the infrastructure of the U.S.; [19]
- The impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods; [20] 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.[21]

While the statute requires that EPA base its determination on an analysis of these factors, it does not establish any numeric criteria, require a specific type of analysis (such as quantitative analysis), or provide guidance on 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.'' [22] These factors were analyzed in the context of the 2020–2022 standard-setting rule that modified volumes under CAA section 211(o)(7)(F),[23] which requires EPA to comply with the processes, criteria, and standards in CAA section 211(o)(2)(B)(ii). Many commenters provided comments about how EPA should weigh these factors. We considered those comments and determined that a holistic balancing of the factors was appropriate.[24] We are taking the same approach in this proposal to holistically balance competing factors. Further evaluation following the proposed rule, and consideration of comments received, will inform how we analyze and weigh these factors in establishing final volumes and standards for 2023 and beyond.

In addition to those factors listed in the statute, we also have authority to consider other factors, including both implied authority to consider factors that inform our analysis of the statutory factors and explicit authority to consider ''the impact of the use of renewable fuels on other factors . . . .'' [25] Accordingly, 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;
- The ability of the market to respond given the timing of this rulemaking;
- Our obligation to respond to the *ACE* remand (Section V);
- The supply of qualifying renewable fuels to U.S. consumers (Section III.A.5) [26];
- Soil quality (Chapter 3.4 of the RIA) [27];
- Environmental justice (Section IV.E and Chapter 8 of the RIA) [28];
- A comparison of costs and benefits (Section IV.D).[29];

C. Statutory Conditions on Volume Requirements

As indicated above, the CAA does not provide instruction on how EPA should consider the factors or the weight each factor should be given when setting the applicable volumes, and thus leaves this to EPA's discretion. However, the Act 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; and
- A floor on the applicable volume of BBD.

Other than these limits, Congress has not provided instruction on how EPA must evaluate the statutorily enumerated factors, and courts have interpreted such congressional silence as conveying substantial discretion to the Agency.[30]

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

[15] In furtherance of this requirement, we have had periodic discussions with DOE and USDA on this proposed action.

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

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

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

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

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

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

[22] 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 (2nd 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).

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

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

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

[26] This is based on our analysis of this same statutory factor as well as of downstream constraints on biofuel use, including the statutory factors relating to infrastructure and costs.

[27] Soil quality is closely tied to water quality and is also relevant to the impact of renewable fuels on the environment more generally.

[28] 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.

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

[30] *Monroe Energy, LLC* v. *EPA,* 750 F.3d 909, 915 (D.C. Cir. 2014) (quoting *Catawba Cty., N.C.* v. *EPA,* 571 F.3d 20, 37 (D.C. Cir. 2009) (''[W]hen a statute is silent with respect to all potentially relevant factors, it is eminently reasonable to conclude that the silence is meant to convey nothing more than a refusal to tie the agency's hands.'').

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.'' [31] 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 applicable volume of conventional renewable fuel within the total renewable fuel volume for years after 2022.

The applicable advanced biofuel volume requirement is 5.63 billion gallons for 2022.[32] 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 proposing 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 proposing are consistent with 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.[33] 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).[34] That is, we are setting the volume requirements such that the mandatory waiver of the cellulosic volume is not likely to be triggered in those future years. Operating within this limitation, we are proposing to set 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.[35]

CAA section 211(o)(7)(D) provides that if ''the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under paragraph (2)(B),'' EPA ''shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year.'' Thus, in order to avoid triggering the mandatory cellulosic waiver, EPA is proposing to set cellulosic volumes at the levels we believe to be achievable. Our discussion of the projected supply of cellulosic biofuel is addressed in Section III.A.1.

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.[36] We are proposing an applicable volume requirement for BBD for 2023, 2024, and 2025 under these authorities.

D. Authority To Establish Percentage Standards for Multiple Future Years

EPA is proposing to establish percentage standards for multiple future years in a single action. 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.[37] Thus, Congress provided EPA discretion as to how to implement the volume requirements of 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.'' [38] The next subparagraph (ii) provides further requirements for the obligation described in paragraph (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. However, EPA could also choose to set percentage standards at one time for several future years (*e.g.,* for 2023–2025 through this rulemaking). Doing so could increase certainty for obligated parties and renewable fuel producers, as both the applicable volume requirements and the associated percentage standards would be established several years in advance of the year in which they would apply. This would also provide 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 would provide certainty as to the date of the compliance deadlines for the years prior to those for which we are proposing to establish percentage standards through this action (*i.e.,* 2022–2024).

Setting percentage standards several years in advance, however, could result in less accurate gasoline and diesel projections being used in calculating the percentage standards. When gasoline and diesel demand projections are made only a few months prior to the subsequent year, those projections tend to be more accurate. Projections further into the future are inherently more uncertain.

In this action, we are proposing 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. We seek comment on this approach.

E. Considerations for Late Rulemaking

In this rulemaking, we are proposing applicable volume targets for the 2023 and 2024 compliance years that miss the

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

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

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

[34] 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).

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

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

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

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

statutory deadlines.[39] 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 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.[40] In doing so, EPA must balance the burden on obligated parties of a delayed rulemaking with the broader goal of the RFS program to reduce GHG emissions and enhance energy security through increases in renewable fuel use.[41] 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.[42] Most relevant here is EPA's action in 2015 that established the BBD volume requirements for 2014 and 2015.[43] There, EPA missed the statutory criterion 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.[44] However, 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 and 2015.[45]

In this rulemaking, we are proposing to exercise 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.[46] We also expect the final rule to be partly retroactive, as the 2023 standards are unlikely to be finalized prior to the beginning of the 2023 calendar year. Nevertheless, as discussed in Section VI.E, we believe that the 2023 standards being proposed in this action could be met. Additionally, we plan to finalize the 2024 standards prior to the beginning of the 2024 calendar year and do not expect those standards to apply retroactively.

In addition, in completing its response to the *ACE* remand of the 2016 annual rule, we are proposing a supplemental standard for 2023.[47] We are proposing this supplemental standard after the statutory deadline for the 2016 standards (November 30, 2015). However, the proposed supplemental standard would prospectively apply to gasoline and diesel produced or imported in 2023. We further discuss our response to the *ACE* remand in Section V.

F. Impact on Other Waiver Authorities

While we are proposing to establish 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.[48] For example, the general waiver authority under CAA section 211(o)(7)(A) provides that EPA may waive the volume targets in ''paragraph (2).'' CAA section 211(o)(2) 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, in the future, EPA could modify the volume targets for 2023 and beyond through the use of our waiver authorities as we have in past annual standard-setting rulemakings.

However, 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, proposing to establish 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 would have 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, proposing to establish 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.[49] There, we cited to the fact 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. 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. Nevertheless, we recognize that the absence of CWCs is potentially a significant change to the operation of the RFS program, and we request comment on EPA's authority to offer CWCs in years in which we do not establish volume requirements using our cellulosic waiver authority.

G. Severability

We intend for the volume requirements and percentage standards for a single year (*i.e.,* 2023, 2024, and 2025) to be severable from the volume

[39] 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.

[40] *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).

[41] *NPRA* v. EPA, 630 F.3d 145, 164–165.

[42] *ACE,* 864 F.3d at 721–22.

[43] 80 FR 77420, 77427–77428, 77430–77431 (December 14, 2015).

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

[45] *ACE,* 864 F.3d at 721–23.

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

[47] We also established a supplemental standard for 2022 in a prior action. 87 FR 39600 (July 1, 2022).

[48] 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).

[49] 87 FR 39600 (July 1, 2022).

requirements and percentage standards for 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, with the exception noted below, are not part of EPA's analysis for the volume requirements and percentage standards for any specific year in 2023 or beyond. Each of the regulatory amendments in Section IX is also severable from the other regulatory amendments because they all function independently of one another. However, we do not intend for the eRIN regulatory provisions (Section VIII) to be severable from the volumes for 2024 and 2025, such that if a reviewing court were to set aside the eRIN program, the volumes for 2024 and 2025 would also be set aside, as those volumes will take into account considerable volumes of cellulosic biofuel expected to be generated utilizing those regulatory provisions. While the projected volumes for years 2024 and 2025 are dependent in part on the eRIN program being in place, the eRIN program, which is designed to last for years beyond 2024 and 2025, is not dependent on the volumes for 2024 and 2025.

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 eRIN program, the individual regulatory amendments) is vacated 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 vacate the volume requirements and percentage standards and supplemental standard, we intend the eRIN provisions and the other regulatory amendments to remain effective. Or, for example, if a reviewing court vacates 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.

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. These factors are listed in Section II.B. Many of those factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract, and so we have opted to analyze those factors based on specific ''candidate volumes'' for each category of renewable fuel. To accomplish this, we derived a set of renewable fuel volumes that we then used to conduct the required multi-factor analyses. We then determined, based on the results of those analyses, the volume requirements that would be appropriate to propose. Our approach can be summarized as a three-step process:

1. Development of candidate volumes;
2. Multifactor analysis based on candidate volumes; and
3. Determination of proposed volumes based on a consideration of all factors analyzed.

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'') [50] 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)), 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, and the availability of qualifying feedstocks. 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.

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 on supply-related considerations is a reasonable first step because doing so narrows the scope for the multifactor analysis in a commonsense way. Without this step, it would be difficult to meaningfully analyze the remaining statutory factors. Our determination of the volume requirements to propose was based not only on our consideration of supply-related factors, but also on the results of our analysis of the other economic and environmental factors discussed in Section IV. Section VI provides our rationale for the proposed volume requirements in light of all the analyses that we conducted.

This section begins with a discussion of the years that we determined would be reasonable to analyze. Section III.B describes our analysis of the supply-related factors for those years, and Section III.C summarizes the resulting candidate volumes. 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. Number of Years Analyzed

Before assessing future supply of renewable fuel, we first considered the number of years to which this assessment would apply, since the nature of this assessment can be different for the nearer term than for the longer term. 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). To some degree, establishing volume targets and the associated percentage standards for a greater number of years would increase market certainty for all parties, and would suggest that EPA should do so for as many years as possible. 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

[50] 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* v. *EPA* (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).

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. 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 and increase the likelihood that applicable standards turn out to be not reasonably achievable and might need to be waived at a later date, we believe that three years represents an appropriate balance at this time.

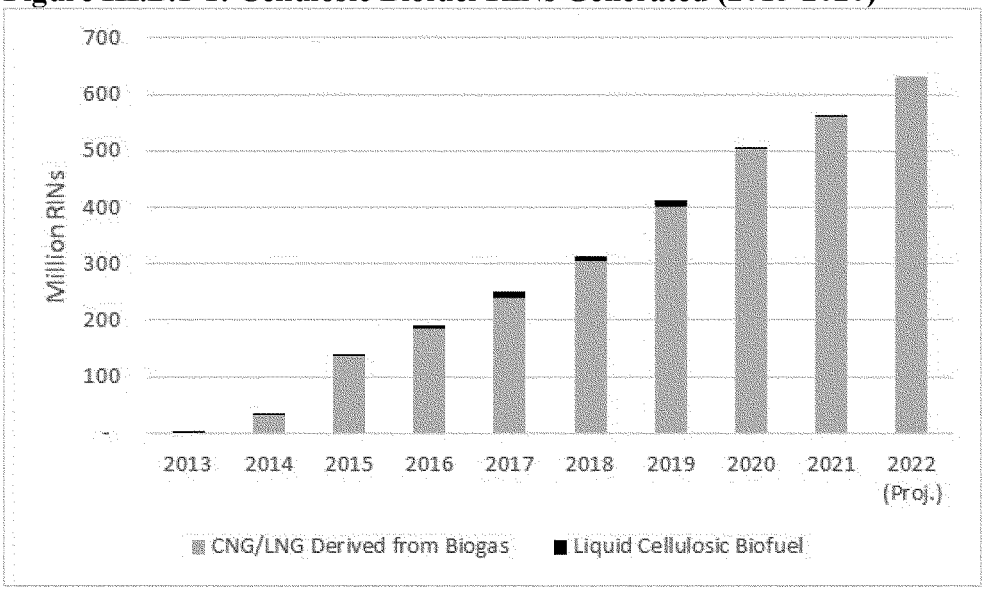
Nevertheless, in our assessment of renewable fuel supply, we have also made projections for one additional year, 2026. As discussed more fully in Section VI.F, we believe that 2026 represents a transitional year in the market's response to the availability of eRINs. Prior to 2026, we expect eRIN generators to use primarily existing generating capacity. By 2026, however, we expect additional electricity generating capacity to come online to take advantage of the new eRIN market. Both this projection and the projection of the amount of electricity that will be used as transportation fuel have uncertainty associated with them, especially at the inception of the eRIN program. Thus, projecting the availability of eRINs for 2026 carries with it greater uncertainty than doing so for 2025 does. This is one important reason that we are not proposing volume requirements for 2026. However, based on the interest on the part of some stakeholders to see volume requirements established for as many years as possible, we believe it is in the public interest for us to estimate potential eRIN generation in 2026 despite the additional uncertainty involved. This estimate is discussed in Section III.C.5 below.

B. Production and Import of Renewable Fuel

1. Cellulosic Biofuel

In the past several years, production of cellulosic biofuel has continued to increase. Cellulosic biofuel production reached record levels in 2021, driven by compressed natural gas (CNG) and liquified natural gas (LNG) derived from biogas. The projected volumes of cellulosic biofuel production in 2022 are even higher than the volume produced in 2021. While the production of liquid cellulosic biofuel has remained limited in recent years (see Figure III.B.1–1), the inclusion of eRINs into the program affords another opportunity for dramatic growth of cellulosic biofuel (see DRIA Chapter 6 for a projection of RIN generation from eRINs in 2023–2025). Despite the significant increase in cellulosic biofuel production since 2014 and the dramatic growth that would result from this proposal, several cellulosic biofuel producers have stated that uncertainty in the demand for cellulosic biofuels and volatility in the cellulosic RIN price has hindered the production of cellulosic biofuel. We recognize the importance of consistent and dependable market signals to the cellulosic biofuel industry. Further discussion of how the RFS program might be able to provide greater certainty to the cellulosic biofuel industry can be found in Section VI.A. 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 DRIA Chapter 5.1.

Figure III.B.1-1: Cellulosic Biofuel RINs Generated (2013-2020)



a. CNG/LNG Derived From Biogas

To project the production of CNG/LNG derived from biogas, we used the same industry wide projection approach that we have used to project the production of this fuel in the RFS standard-setting annual rules since 2018 and that has been reasonably successful in projecting volumes. This methodology projects the production of CNG/LNG derived from biogas based on a year-over-year growth rate applied to the current rate of production of cellulosic biogas. We calculated the year-over-year growth rate in CNG/LNG

derived from biogas by comparing RIN generation from January 2021 to December 2021 (the most recent 12 months for which data are available) to RIN generation in the 12 months that immediately precede this time period (January 2020 to December 2020). The growth rate calculated using this data is 13.1 percent. These RIN generation volumes are shown in Table III.B.1.a–1.

TABLE III.B.1.a–1—GENERATION OF CELLULOSIC BIOFUEL RINS FOR CNG/LNG DERIVED FROM BIOGAS

[Ethanol-equivalent gallons]

RIN generation (June 2020–May 2021) (million)	RIN generation (June 2021–May 2022) (million)	Year-over-year increase (%)
526.1	595.1	13.1

In previous annual rules we applied the year-over-year growth rate to actual supply in the most recent calendar year for which a full year of data is available. For instance, when determining the original 2020 standards for cellulosic biofuel, we used actual supply of cellulosic RINs generated and made available for compliance in 2018. For this proposal, the most recent full calendar year for which we have data on RIN supply is 2021. Applying the 13.1 percent annual growth rate twice to the 2021 RIN supply provides a two-year projection, *i.e.,* for 2023. Applying this same growth rate can then be used to project volumes of CNG/LNG derived from biogas in subsequent years. This methodology results in the projections of CNG/LNG derived from biogas in 2023 to 2025 shown in Table III.B.1.a–2.

TABLE III.B.1.a–2—PROJECTED GENERATION OF CELLULOSIC BIOFUEL RINS FOR CNG/LNG DERIVED FROM BIOGAS

[Ethanol-equivalent gallons]

Year	Date type	Growth rate (%)	Volume (RINs) (million)
2021	Actual	N/A	561.8
2023	Projection	13.1	719.3
2024	Projection	13.1	813.9
2025	Projection	13.1	920.9

While we have successfully used this methodology in previous years to project the production of CNG/LNG derived from biogas with reasonable accuracy there are several factors that may impact the accuracy of this methodology out to 2025. In previous annual rules this methodology was used to project the production of CNG/LNG derived from biogas out 1–2 years in the future. As the methodology relies on historical data to project future production, the uncertainty associated with the projections is expected to increase the further out into the future the projections are extended. In particular, we are aware of several market factors that may impact the rate of growth of CNG/LNG derived from biogas in future years. One important factor is the quantity of CNG/LNG able to be used for transportation fuel. Under the RFS program RINs may only be generated for CNG/LNG that is used as transportation fuel, and the quantity of CNG/LNG used as transportation fuel is relatively limited in the U.S. We currently project that use of CNG/LNG as transportation fuel will be approximately 1.4–1.75 billion ethanol-equivalent gallons in 2023–2025.[51] While these projections of CNG/LNG use as transportation fuel might appear unlikely to limit RIN generation for the candidate volumes through 2025, it is highly unlikely that registered parties will be able to document and verify the use of all CNG/LNG use in the transportation sector. Since this documentation is a requirement under the regulations, generation of RINs for CNG/LNG derived from biogas will likely be limited to a quantity somewhat less than the total amount of CNG/LNG used in the transportation sector.

There are also potential limitations related to the available supply of CNG/LNG derived from biogas. Currently, a significant volume of biogas is produced at landfills and wastewater treatment plants across the U.S.[52] Some of this biogas is currently being flared or used to produce electricity onsite. There are also significant opportunities for increasing the production of biogas from manure and other agricultural residues. However, biogas must be used as transportation fuel to be eligible to generate RINs.[53] Raw biogas from landfills, wastewater treatment facilities, or agricultural digesters must be treated before it can be used as transportation fuel, either at on site fueling stations or transported to fueling stations via the natural gas pipeline network. Collecting and treating the raw biogas to enable it to be used as CNG/LNG requires a significant capital investment. While the quantity of biogas that could be used as transportation fuel exceeds the quantity of CNG/LNG actually used as transportation fuel, much of this biogas is not currently being treated to the level necessary to enable its use as CNG/LNG and thus to generate RINs.[54]

Another factor that may limit the future rate of growth in the installation of equipment necessary to upgrade raw

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

[52] EPA Landfill Methane Outreach Program Landfill and Project Database; Accessed March 2022.

[53] See definition of ''renewable fuel'' in 40 CFR part 80 Section 1401.

[54] According to the American Biogas Council there are currently over 2,200 sites producing biogas in the U.S. (see Biogas Industry Market Snapshot—American Biogas Council, available in the docket). Approximately 860 of these sites use the biogas they produce, and of this total 138 facilities generated RINs for CNG/LNG derived from biogas used as transportation fuel in 2021.

biogas to transportation fuel quality is the availability of financial incentives provided by state Low Carbon Fuel Standard (LCFS) programs. Since its inception in 2011 California's LCFS program has provided credits for CNG/LNG derived from biogas that is used as transportation fuel in California. Since 2014 when CNG/LNG derived from biogas was determined to qualify as cellulosic biofuel in the RFS program, the quantity of this fuel used with the incentives of both programs (RFS and California's LCFS) has increased dramatically. It is likely that this rapid expansion was driven by the ability for this fuel to generate lucrative credits under both programs. As of 2021, however, the LCFS data indicates that the quantity of fossil CNG/LNG generating credits under the LCFS program had decreased to approximately 4 million diesel gallon equivalents.[55] This significant reduction suggests that the ability for new sources of CNG/LNG derived from biogas to displace CNG/LNG derived from fossil-based natural gas in California and generate LCFS credits may be limited, which may in turn have an impact on the economics and rate of developing new projects to produce this fuel going forward. Currently Oregon is the only other state that has adopted a clean fuels program, and the opportunity for CNG/LNG derived from biogas to realize financial incentives in this program is limited by the size of the Oregon CNG/LNG fleet. If other states adopt programs similar to California's LCFS or Oregon's Clean Fuels program, these other state programs could provide additional incentives for the increased production and use of CNG/LNG derived from biogas.[56]

Another significant limitation on the growth of CNG/LNG derived from biogas is the cost associated with establishing a pipeline interconnect. Not all CNG/LNG vehicles will be situated such that they can refuel at the location where the biogas is produced and upgraded. Therefore, getting the upgraded biogas to CNG/LNG vehicles requires that it be put into common carrier pipelines. If there are no pipelines near the source of the biogas, then it can quickly become cost prohibitive and/or require considerable time to put in place a stub pipeline to connect to the common carrier pipeline.

An important new variable in this limitation on biogas-based CNG/LNG production is the eRIN provisions being proposed in this action. With the opportunity to generate eRINs from biogas beginning January 1, 2024, instead of requiring a natural gas pipeline interconnect, a facility would only need an electrical connection—something far less expensive and more readily available. While these proposed regulations are expected to quickly incentivize the expansion of the use of biogas for electricity, their expansion may outcompete further development of projects to produce CNG/LNG derived from biogas; the economics may make it more cost effective to convert biogas to electricity to generate eRINs than to upgrade the biogas for use in CNG/LNG vehicles. For further discussion of the relative costs of using of biogas as CNG/LNG versus using that biogas to produce electricity, see DRIA Chapter 9.

With these potential limitations in mind, it may be appropriate to view the projected production volumes of CNG/LNG derived from biogas in this section based on the historical methodology using historical trends as the highest volumes that could be achieved through 2025.

b. Renewable Electricity

Because we are proposing a new, comprehensive regulatory program for eRINs, it was necessary to derive a projection methodology for the quantity of renewable electricity that can be made available. This methodology is described in DRIA Chapter 6.1.4. In overview, the methodology relies on an evaluation of just two pieces of information: projected electricity demand from the fleet of electric vehicles (EVs) in 2024 and 2025 and the projected production of renewable electricity from combustion of qualifying biogas in those same years. We assessed potential electricity demand using EV sales projections from the Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions Standards,[57] along with information on the size of the existing EV fleet. We assessed potential renewable electricity production using data from a number of sources and adjusted that production level to account for line losses. The lesser of renewable electricity production and demand then determined the maximum quantity of eRINs that could be generated in each year of the program. We are proposing to use these resulting maximum values in setting the cellulosic biofuel standards for 2024 and 2025. For 2024 and 2025 the electricity demanded by the EV fleet would be the limiting factor, however, this is likely to flip in future years. These RIN generation volumes are shown in Table III.B.1.b–1. We seek comment on the appropriateness of the methodology used as described more fully below and in DRIA Chapter 6.1.4, as well as on the resulting eRIN volume projections.

TABLE III.B.1.b–1—PROJECTED GENERATION OF CELLULOSIC BIOFUEL RINS FOR ELECTRICITY DERIVED FROM BIOGAS

[Ethanol-equivalent gallons]

Year	Volume (million RINs)
2023	n/a
2024	600
2025	1,200

We are aware that there is inherent uncertainty for both supply and demand when it comes to projecting eRIN volumes. Regarding demand, qualifying renewable electricity will be a direct function of the number of EVs sold and registered over the timeframe of this action. The size of the existing fleet of EVs is known, but due to the rapid rate of growth of EV sales, we anticipate that the current size of the EV fleet will comprise a relatively small proportion of the total quantity of EVs eligible to generate RINs by 2025. Consequently, the cellulosic biofuel volumes that we are proposing in this action are highly dependent upon the EV sales projections we are using.

Regarding the supply of renewable electricity generated from qualifying biogas (*i.e.,* biogas that is produced from renewable biomass consistent with an EPA-approved pathway), there is less uncertainty because data is collected and reported by EIA on this activity. However, two predominant sources of uncertainty remain despite EIA data collection. First, the EIA data does not delineate between which sources of biogas may or may not qualify for the existing EPA-approved pathways. Second, although we anticipate there being ample financial benefit from the eRIN program to justify participation, the rate at which small and independent generators may be able to begin participation in the program is unknown. As described in DRIA Chapter 6.1.4.2, our assessment is that a majority of the generating capacity will be able to participate at the onset of the

[55] Data from the LCFS Data Dashboard (*https://www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm*). For context, in 2021 approximately 174 million diesel gallon equivalents of bio-CNG/LNG generated credits in the LCFS program.

[56] For instance, Washington is in the process of developing its own Clean Fuels Program and is targeting January of 2023 for it to begin. See ''Clean Fuel Standard—Washington State Department of Ecology,'' available in the docket.

[57] 86 FR 74434 (December 30, 2021).

program and that the remaining capacity will register within a few years.

The addition of cellulosic volumes for electricity from renewable biomass to the RFS program will comprise a large, and growing, fraction of the cellulosic standard over the timeframe of this action. We anticipate that as the eRIN program matures the associated uncertainty in projecting future volumes will decrease. As mentioned in the prior section on biogas to CNG/LNG, we anticipate that the addition of regulations governing the generation of RINs for renewable electricity may influence the decision making of biogas project developers. Nevertheless, the cellulosic volumes we are proposing for eRINs are not dependent upon any potential shift in developer preference for electricity projects. We will continue to monitor the market closely and intend to use updated data and information to project the potential production of eRINs through 2025 in the final rule.

c. 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 possible exception is the production of ethanol from corn kernel fiber, 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. 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.[58] This guidance highlighted several outstanding critical technical issues that need to be addressed. At this time there is still considerable uncertainty about whether resolution of existing questions will allow for significant additional volume of cellulosic biofuel to be available through 2025 as well as the volume of cellulosic ethanol that could be produced from corn kernel fiber. We therefore have not included volumes from additional facilities that intend to produce cellulosic ethanol from corn kernel fiber co-processed with corn starch in our projections of cellulosic biofuel production in 2025. We request comment on whether EPA should include additional volumes of cellulosic ethanol produced from corn kernel fiber in our projection of cellulosic biofuel for 2023–2025, and if so, how we should project it and what those volumes should be.

d. Other

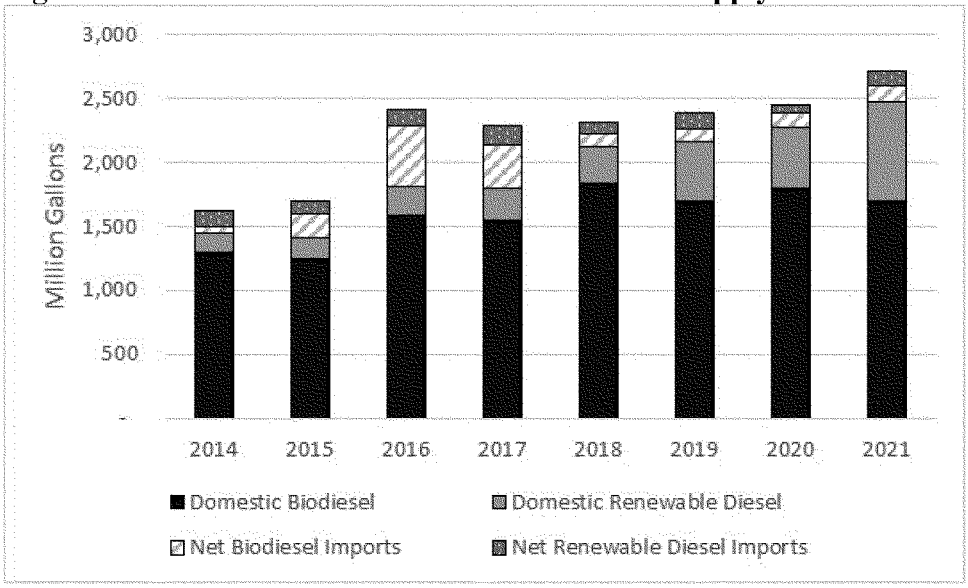
For the 2023–2025 timeframe, we expect that commercial scale production of cellulosic biofuel in the U.S. will be limited to electricity and CNG/LNG derived from biogas. In previous years several foreign cellulosic biofuel facilities have also supplied ethanol produced from sugarcane bagasse and heating oil produced from slash, precommercial thinnings, and tree residue. Further, 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 been able to achieve consistent production of liquid cellulosic biofuel in the U.S., production from these facilities in 2023–2025 is highly uncertain and likely to be relatively small (see Chapter 5.1 of the RIA for more detail on the potential production of liquid cellulosic biofuel through 2025). For the candidate volumes we projected that there would be no production of liquid cellulosic biofuel in 2023, and that liquid cellulosic biofuel would grow to 5 million and 10 million ethanol-equivalent gallons in 2024 and 2025 respectively.

2. Biomass-Based Diesel

Since 2010 when the biomass-based diesel (BBD) volume requirement was added to the RFS program, production of BBD has generally increased. The volume of BBD supplied in any given year is influenced by a number of factors including production capacity, feedstock availability and cost, available incentives including the RFS program, the availability of imported BBD, the demand for BBD in foreign markets, and several other economic factors. 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., increasing volumes of renewable diesel have also been supplied. Production and import of renewable diesel are expected to continue to increase in future years.

[58] 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).

Figure III.B.2-1: Biodiesel and Renewable Diesel Supply 2012-2021[a]



[a] Numbers are based on RIN generation data from the EPA Moderated Transaction System (EMTS). This figure does not include fuels that did not generate RINs. This figure also does not include conventional biodiesel and renewable diesel, which are discussed in Section III.B.4.b and DRIA Chapter 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).[59] 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 refinery process that produces renewable diesel from waste fats, oils, and greases or plant oils also 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 5 million gallons per year—opportunities for increasing this category of advanced biofuel exist. In particular, other technologies and feedstocks are being developed that might enable new sources of SAF. In addition, in April 2022 the 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.

Since the vast majority of BBD is biodiesel and renewable diesel, and since feedstock limitations are likely to cause any growth in renewable jet fuel to come at the expense of biodiesel and renewable diesel, we have focused on just biodiesel and renewable diesel in this section. The remainder of this section 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. Further details on these volume projections can be found in DRIA 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 has remained at approximately 1.8 billion gallons per year. 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.[60] In August 2017, the U.S. announced tariffs on biodiesel imported from Argentina and Indonesia.[61] These tariffs were subsequently confirmed in April 2018.[62] 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. Data reported by EIA shows that biodiesel production capacity in February 2022 was approximately 2.2 billion gallons per year.[63] According to EIA data biodiesel production capacity grew slowly from about 2.15 billion gallons in 2012 to a peak of approximately 2.5 billion gallons in 2018. 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

[59] According to EMTS data renewable jet fuel production has ranged from 2–4 million gallons per year from 2016–2021.

[60] 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.

[61] 82 FR 40748 (August 28, 2017).

[62] 83 FR 18278 (April 26, 2018).

[63] EIA Monthly Biofuels Feedstock and Capacity Update (*https://www.eia.gov/biofuels/update*).

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

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, both domestic production and imports of renewable diesel have increased. Renewable diesel production facilities generally have higher capital costs and production costs relative to biodiesel, which likely accounts for the much higher volumes of biodiesel production relative to renewable diesel production to date. The higher cost of renewable diesel production can largely be off-set through the benefits of economies of scale as 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 and provides a significant advantage over biodiesel, which has largely saturated the California market.[64] 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 DRIA Chapter 6.2 for further discussion.

Domestic renewable diesel production capacity has increased significantly in recent years from approximately 280 million gallons in 2017 to nearly 1.5 billion gallons in February 2022.[65] Additionally, a number of parties have announced their intentions to build new renewable diesel production capacity with the potential to begin production by the end of 2025. These new facilities include new renewable diesel production facilities, expansions of existing renewable diesel production facilities, and the conversion of units at petroleum refineries to produce renewable diesel. In total over 5 billion gallons of new renewable diesel capacity has been announced,[66] though it is likely 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.[67] 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 it is possible that feedstock limitations may result in renewable diesel facilities operating below their production capacity. In light of the high capital cost for these facilities, however, it appears more likely that the announced renewable diesel facilities will not be built if sufficient feedstock to operate these facilities at or near their production capacity cannot be secured. We therefore expect that domestic renewable diesel production is likely to increase along with production capacity through 2025.

In addition to domestic production the U.S. has also imported significant volumes of renewable diesel, with nearly all of the imported renewable diesel coming from Singapore. 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. 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, though 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

When considering the likely production and import of biodiesel and renewable diesel in future years the availability of feedstock is an important consideration. Currently, biodiesel and renewable diesel in the U.S. are produced from a number of different feedstocks including fats, oils and greases (FOG), distillers corn oil, and virgin vegetable oils such as soybean oil and canola oil. 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.

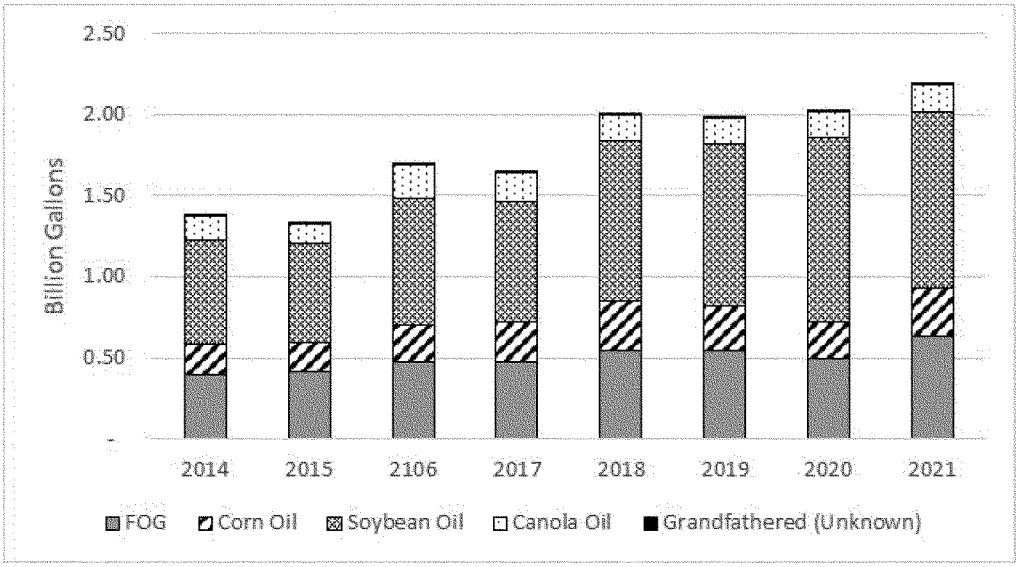
[64] In 2021 nearly all renewable diesel consumed in the U.S. was consumed in California. Together renewable diesel and biodiesel represented approximately 26 percent of all diesel fuel consumed in California in 2021.

[65] 2017 renewable diesel capacity based on facilities registered in EMTS. February 2022 renewable capacity based on EIA Monthly Biofuels Feedstock and Capacity Update.

[66] *U.S. Renewable Diesel Capacity Could Increase Due to Announced and Developing Projects.* EIA Today in Energy. July 29, 2021.

[67] 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.*

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 38 percent in the 2020/2021 agricultural marketing year. 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 there has been a corresponding increase in competition for these feedstocks between biodiesel and renewable diesel. 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. By August 2021, the percentage of the soybean value that came from the soybean oil had increased to approximately 50 percent. This competition is expected to continue to increase through 2025.

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 these feedstocks, 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, and 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 are limited, however, and 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. Data from 2021 appears to support this expectation, with increased soybean oil representing approximately half of the increase in feedstocks used to produce renewable diesel in the U.S. from 2020 to 2021.

One likely source of feedstock for expanding renewable diesel production in 2023–2025 is soybean oil 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.[68] This new crushing capacity is expected to come online in the 2023–2025 timeframe. Increase crushing of soybeans in the U.S. will increase domestic soybean oil production. 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.

d. Projected BBD Production and Imports

We project that the supply of BBD to the U.S. will increase through 2025. We project that the largest increases will come from domestic renewable diesel as new production facilities come online and ramp up to full production. 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 is that opportunities for biodiesel expansion in California, where producers can benefit from LCFS credits in addition to RFS incentives, are very limited while there is significant opportunity for the expansion of renewable diesel consumption in California. The availability of LCFS credits will likely be a significant factor in the competition between biodiesel producers and renewable producers for access to new feedstocks, particularly feedstocks with low carbon intensity (CI) scores in California's LCFS program. While we project most of the biodiesel and renewable supplied to the U.S. will be produced domestically, we project that imports of both biodiesel and renewable diesel will continue to

[68] For example, see Demaree-Saddler, Holly. *Cargill plans US soy processing operations expansion.* World Grain. March 4, 2021, and Sanicola, Laura. *Chevron to invest in Bunge soybean crushers to secure renewable feedstock.* Reuters. September 2, 2021.

contribute to the supply of these fuels through 2025.

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.[69] However, these biofuels have been consumed in much smaller quantities than biodiesel and renewable diesel in the past, and/or have been highly variable. In order to estimate the volumes of these other advanced biofuels that may be available in 2023–2025, we employed a methodology originally presented in the annual rulemaking establishing the applicable standards for 2020–2022.[70] 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 DRIA Chapter 5.4.

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

Fuel	Volume (million RINs)
Imported sugarcane ethanol	110
Domestic ethanol	25
CNG/LNG	5
Heating oil	2
Naphtha	33
Renewable diesel	81
Total	256

As the available data does not permit us to identify an unambiguous upward or downward trend in the historical consumption of these other advanced biofuels, we propose to use the volumes in the table above for all years covered in this proposed rule (*i.e.,* 2023–2025).

4. Conventional Renewable Fuel

Conventional renewable fuel includes any renewable fuel made from renewable biomass as defined in 40 CFR 80.1401, does not qualify as advanced biofuel, and which 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.[71]

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.

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. Corn starch ethanol is prohibited by statute from being an advanced biofuel regardless of its GHG performance in comparison to gasoline.[72]

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. Waste industrial ethanol and ethanol made from non-cellulosic portions of separated food waste have been produced more sporadically and at even lower volumes. We have ignored these other sources for our purposes here as they do not materially affect our assessment of volumes of conventional ethanol that can be produced.

Total domestic corn ethanol production capacity increased dramatically between 2005 and 2010 and increased at a slower rate thereafter. In 2020, production capacity had reached 17.4 billion gallons.[73] [74] This production capacity was significantly underused in 2020 because the COVID–19 pandemic depressed gasoline demand in comparison to previous years and thus ethanol demand in the form of E10. Actual production of denatured ethanol in the U.S. reached just 12.82 billion gallons in 2020, compared to 14.72 billion gallons in 2019. Denatured ethanol production partially recovered in 2021, reaching 14.09 billion gallons.[75]

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 to a smaller degree the demand for E0, E15, and E85, and we have incorporated projected growth in opportunities for sales of E15 and E85 into our assessment. While production of corn ethanol could in theory be limited by production capacity, in reality there is an excess of production capacity 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 below. Thus, it does not appear that production capacity will be a limiting factor in 2023–2025 for meeting the candidate volumes.

b. Biodiesel and Renewable Diesel

Other than corn ethanol, the only other conventional renewable fuels that have been used above de minimis 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.

Actual global production of palm oil biodiesel and renewable diesel was about 3.7 billion gallons in 2019.[76] The

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

[70] 87 FR 39600 (July 1, 2022).

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

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

[73] ''2021 Ethanol Industry Outlook—RFA,'' available in the docket.

[74] ''Ethanol production capacity—EIA April 2021,'' available in the docket.

[75] ''RIN supply as of 1–31–22,'' available in the docket.

[76] Total worldwide production of biodiesel and renewable diesel was 46.8 billion liters in 2019 (see ''OECD–FAO Agricultural Outlook 2020–2029 data for biodiesel & renewable diesel''), of which 30

Continued

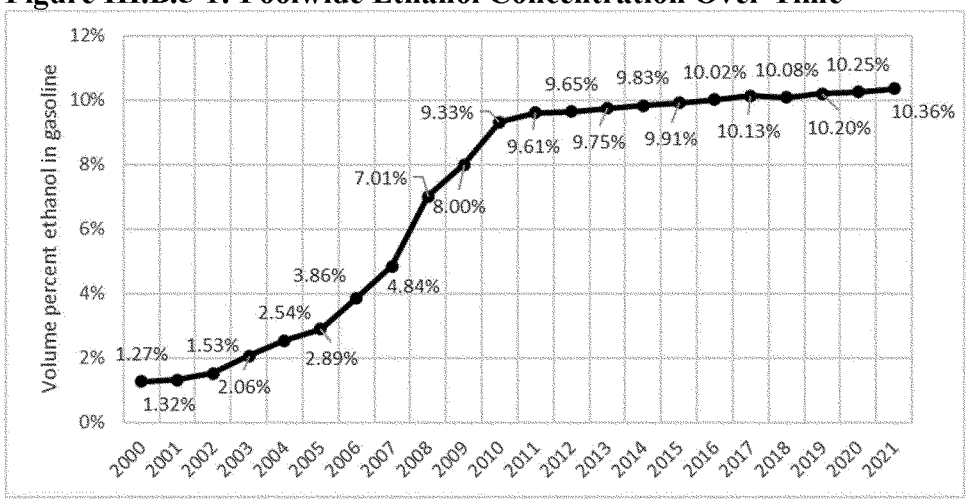
U.S. could be an attractive market for this foreign-produced conventional biodiesel and renewable diesel if domestic demand for conventional renewable fuel exceeded domestic supply, *i.e.,* the amount of ethanol that could be consumed combined with domestic production of conventional biodiesel and renewable 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 over 3.6 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.[77] After 2016, 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 and being zero since 2017.[78] 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.

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



As the average ethanol concentration approached and then exceeded 10.00 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 10.00 percent only insofar as the ethanol in E15 and E85 exceeds the ethanol content of E10 and more than offsets the volume of E0. 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. The results are shown below. Details of these calculations can be found in the DRIA.

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

Year	Projected ethanol concentration (%)	Projected ethanol consumption (million gallons)
2023	10.44	14,590
2024	10.49	14,640
2025	10.53	14,669

percent was from palm oil (see page 206 of ''OECD–FAO Agricultural Outlook 2021–2030'').

[77] ''RIN supply as of 3–22–21,'' available in the docket.

[78] ''RIN supply as of 3–22–21,'' available in the docket.

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 subjected to the other economic and environmental analyses required by the statute. This section describes the candidate volumes, while Section IV summarizes the results of the additional analyses we performed.

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 parsimonious as analyzing the statutory categories 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

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. BBD volumes did not increase after 2012, 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 intended to be on growth in cellulosic biofuel volumes, which have the greatest greenhouse gas reduction threshold. The statutory cellulosic waiver provision, while acknowledging that the statutory cellulosic biofuel volumes may not be met, nevertheless expressed 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 on cellulosic biofuel in the RFS program is likely due to the expectations among proponents of cellulosic biofuel that it 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),[79] that cellulosic biofuel feedstocks could be produced or collected with relatively few negative environmental impacts, that the feedstocks would be inexpensive, allowing for lower cost biofuels to be produced than those produced from feedstocks with other primary uses such as food, and that the technological breakthroughs needed to convert cellulosic feedstocks into biofuel were right around the corner.

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 2022–2025, after taking into consideration the incentives provided by the RFS program and other available state and federal incentives. The candidate volumes for 2022–2025 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, CNG/LNG derived from biogas, and eRINs separately. Note that consistent with the proposed regulations for eRINs in this proposed rule, the candidate volumes for 2023 do not include any generation of cellulosic RINs from eRINs.

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

[Million RINs]

	2023	2024	2025
Liquid Cellulosic Biofuel	0	5	10
CNG/LNG Derived from Biogas	719	814	921
eRINs	0	600	1,200
Total Cellulosic Biofuel	719	1,419	2,131

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. It remained at 4.5 billion gallons for three years before finally rising to 5.0 billion gallons in 2022.

In calculating the applicable percentage standards in the past, we have used volumes for non-cellulosic advanced biofuel that are at least as high as those derived from the statutory targets, and occasionally higher. For 2022, we have set the implied volume requirement for non-cellulosic advanced biofuel at 5.0 billion gallons, equivalent to the implied volume target in the statute.[80] As described in that rule, we believe that this level can be reached, though likely not without market adjustments that could include some diversion of soybean oil from food and other uses to biofuel production.

For years after 2022, we anticipate that the growth in the production of feedstocks used to produce advanced

[79] See definition of ''cellulosic biofuel'' at 40 CFR part 80 Section 1401.

[80] 87 FR 39600 (July 1, 2022).

biodiesel and renewable diesel (the two non-cellulosic advanced biofuels projected to be available in the greatest quantities through 2025) will be limited, particularly in the U.S. 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 high-GHG feedstocks in non-biofuel markets as low-GHG feedstocks are increasingly used for biofuel production, then it would prove counterproductive. Further, as discussed in greater detail in Section III.C.3 below, significant volumes of non-ethanol advanced biofuels beyond what would be needed to meet the implied non-cellulosic advanced biofuel category are likely to also be needed to meet an implied conventional renewable fuel volume of 15.25 billion gallons.[81]

Based on these considerations, we believe that increases in the implied volume for non-cellulosic advanced biofuel in the 2023–2025 timeframe should be relatively small in comparison to the 500 million RIN increase that occurred in 2022. As a result, we believe that an annual increase of 100 million RINs as shown below would be reasonable. We also note that this increase (100 million RINs per year) is consistent with the projected increase in domestic soybean oil production through 2025 if the entire volume were used to produce biodiesel and/or renewable diesel.[82]

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

[Million RINs]

Year	Volume
2023	5,100
2024	5,200
2025	5,300

[81] In 2023, the candidate volume for conventional renewable fuel would be 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. We sometimes refer to 15.25 billion gallons in 2023 as the effective volume requirement for conventional renewable fuel.

[82] USDA Agricultural Projections to 2031. Soybean oil production is projected to increase from 25,535 million pounds in 2021/22 to 27,475 million pounds in 2025/2026. This represents an average annual increase of 485 million pounds per year, which could be used to produce approximately 65 million gallons of biodiesel or renewable diesel. This volume of fuel could generate between 95 million and 110 million RINs, depending on the equivalence value of the fuel produced.

3. Conventional Renewable Fuel

As for non-cellulosic advanced biofuel, the implied statutory volume targets for conventional renewable fuel in prior years represent a useful point of reference in the consideration of candidate volumes that may be appropriate for 2023–2025. Under the statute, conventional renewable fuel increased every year between 2009 and 2015, after which it remained at 15 billion gallons through 2022. In calculating the applicable percentage standards in the past, we have used 15 billion gallons in most years between 2017 and 2022.[83] Thus as a starting point, consistent with our approach to setting standards in recent years, we considered whether 15 billion gallons of conventional renewable fuel would be appropriate for 2023–2025.

However, we note that the inclusion of a supplemental volume requirement of 250 million gallons in 2022 to address the remand of the 2016 standards effectively results in an implied conventional renewable fuel volume requirement of 15.25 billion gallons. Since we are also proposing to include a supplemental volume requirement of 250 million gallons in 2023 as described in Section V, an implied volume requirement of 15 billion gallons for conventional renewable fuel would also effectively be 15.25 billion gallons in 2023. As discussed in the final rule which established the applicable volume requirements for 2022, we believe that a 15.25 billion gallon implied volume requirement for conventional renewable fuel can be met without the need for obligated parties to use carryover RINs for compliance. The same is true for 2023–2025; not only do we project that total ethanol consumption in these years will be higher than it was in 2022, but we also project that sufficient excess volumes of advanced biodiesel and renewable diesel can be supplied in 2023–2025. Thus, we believe that a volume of 15.25 billion gallons in 2024 and 2025 is an appropriate candidate volume for consideration. We expect that the market will have adjusted to providing this volume in 2022 in meeting the combination of the conventional renewable fuel implied volume requirement and the supplemental volume requirement, and we project that the market could do so as well for 2023, so it would be consistent with available supply to consider 15.25 billion gallons as a candidate volume for 2024 and 2025 as well. However, for purposes of analyzing the other environmental and economic impacts, we treat the proposed 2023 supplemental volume requirement separately as discussed in DRIA Chapter 3.3; the candidate volumes which we subjected to the other analyses described in Section IV do not include the impacts of the supplemental volume requirement.[84]

Additionally, in considering a candidate volume of 15.25 billion gallons of conventional renewable fuel in 2024 and 2025, we believe that obligated parties would seek out RINs representing new renewable fuel consumption to comply with the supplemental volume requirement to the extent they are able, even though the supplemental volume requirement in 2023 could be met with carryover RINs. In past years we have noted a preference on the part of obligated parties for using RINs associated with new renewable fuel consumption when possible, preserving their individual carryover RIN banks for use in the event that future supply falls short of that needed to meet the applicable standards. As a result, we have assumed for purposes of analyzing the impacts of this proposed rule that no carryover RINs would be used to meet a candidate conventional renewable volume of 15.25 billion gallons, and this provides additional justification for the consideration of a candidate volume of 15.25 billion gallon for conventional renewable fuel in 2024 and 2025.

As in past years, we do not expect that the implied conventional renewable volume would be achievable through the consumption of ethanol alone. As described in Section III.B.5, we estimate that ethanol consumption will continue to fall short of 15.25 billion gallons in the 2023–2025 timeframe, even under the market influences of the RFS program and with ongoing efforts to expand offerings of E15 and E85 at retail service stations. Instead, there are a variety of means through which the market could meet a 15.25 billion gallon

[83] While the 2020 implied volume requirement was originally set at 15 billion gallons (85 FR 7016, February 6, 2020), we have 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 have set the implied volume requirement for conventional renewable fuel at the level actually consumed.

[84] Although the effective implied volume requirement for conventional renewable fuel would be 15.25 bill RINs for all years 2023–2025, in 2023 this implied volume requirement would in reality be represented by 15.00 bill RINs for conventional renewable fuel and 0.25 bill RINs for the supplemental standard.

candidate volume for conventional renewable fuel, such as:[85]

- Reductions in the consumption of E0;
- Consumption of non-ethanol advanced biofuel, such as biodiesel and renewable diesel, in excess of the applicable advanced biofuel standard; and
- Domestic production and/or importation of conventional biodiesel or renewable diesel.

As a result, our assessments from previous years remain applicable for 2023–2025 in broad strokes: 15.25 billion gallons of conventional renewable fuel is achievable through some collection of the avenues listed above. We believe it is appropriate to analyze this volume of conventional renewable fuel as part of the candidate volumes, even though corn ethanol alone would not be sufficient to meet that volume.

The amount of corn 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.

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

[Million gallons]

	2023	2024	2025
Ethanol in all blends	14,590	14,640	14,669
Cellulosic ethanol	0	0	0
Imported sugarcane ethanol	110	110	110
Domestic advanced ethanol	25	25	25
Corn ethanol	14,455	14,505	14,534

Since corn ethanol consumption would be about 14.5 billion gallons, there would need to be about 0.75 billion ethanol-equivalent gallons of non-ethanol renewable fuel in order for an effective conventional renewable fuel volume of 15.25 billion gallons to be met.

As discussed in Section III.C.2, we project that more non-cellulosic advanced biofuel can be made available than would be needed to meet the non-cellulosic advanced biofuel candidate volumes shown in Table III.C.2–1. The total volume of non-cellulosic advanced biofuel that we project can be produced and consumed in 2023–2025 is shown below. Details are provided in the DRIA Chapter 5.

TABLE III.C.3–2—TOTAL NON-CELLULOSIC ADVANCED BIOFUEL CANDIDATE VOLUMES

[Million RINs]

	2023	2024	2025
Advanced biodiesel	2,580	2,530	2,480
Advanced renewable diesel[a]	3,054	3,154	3,275
Advanced jet fuel	5	5	5
Other advanced biofuel	256	256	256
Total	5,895	5,945	6,016

[a] Represents only biomass-based diesel 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.

The total volumes of non-cellulosic advanced biofuel that can be supplied would be in excess of the candidate volumes we have considered in this action.

TABLE III.C.3–3—EXCESS NON-CELLULOSIC ADVANCED BIOFUEL

[Million RINs]

	2023	2024	2025
Total supply	5,895	5,945	6,016
Candidate volume requirement	5,100	5,200	5,300
Excess	795	745	716

This excess non-cellulosic advanced biofuel would make up for the shortfall in corn ethanol, enabling an implied conventional volume of 15.00 billion gallons in 2023 and 15.25 billion gallons in 2024 and 2025 to be met, and also enable the 250 million gallon supplemental volume to be met.

[85] Carryover RINs also represent a legitimate compliance approach. However, since they do not represent new supply of renewable fuel, they are not appropriate for including in the candidate volumes for purposes of analyzing impacts.

TABLE III.C.3–4—MEETING THE CANDIDATE VOLUME FOR CONVENTIONAL RENEWABLE FUEL

[Million RINs]

	2023	2024	2025
Corn ethanol	14,455	14,505	14,534
Excess non-cellulosic advanced biofuel	[a] 545	745	716
Total	15,000	15,250	15,250

[a] An additional 250 million RINs of excess non-cellulosic advanced biofuel would also be available to fulfill 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 the 2023–2025 timeframe. 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 foreign production capacity for qualifying palm-based biodiesel and renewable diesel is over 3.6 billion gallons.

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. A consideration of carryover RINs is also consistent with the statutory requirement at 211(o)(2)(B)(ii) that, in the context of determining appropriate volume requirements for years after 2022, we review the implementation of the program in prior years. 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 proposed 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 our regulations limit the use of these carryover RINs to 20 percent of the obligated party's renewable volume obligation (RVO).[86] For the bank 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 2020 carryover RINs must be used for compliance with 2021 compliance year obligations, or they will expire. However, vintage 2021 RINs can then be ''banked'' for use toward 2022 compliance.

As noted in past RFS annual rules, carryover RINs are a foundational element of the design and implementation of the RFS program.[87] A bank of carryover RINs is extremely 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.[88] 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 carryover RIN bank 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, the collective carryover RIN bank provides 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 allowing for the generation and use of credits.

EPA can also rely on the availability of carryover RINs to support market-forcing volumes that may not be able to be met with renewable fuel production and use in that year, and 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

[86] 40 CFR 80.1427(a)(5).

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

[88] 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).

production and import, justified maintaining the advanced and total renewable fuel volume requirements for that year at the levels specified in the statute.[89]

a. Carryover RIN Bank Size

After compliance with the 2019 standards, we project that there are approximately 1.83 billion total carryover RINs available.[90] This is the same total number of carryover RINs that were estimated to be available in the 2020–2022 final rule. Since we set both the 2020 and 2021 volume requirements at the actual volume of renewable fuel consumed in those years, we project that 1.83 billion total carryover RINs will be available for compliance with the 2022 standards (including the 2022 supplemental standard) as well. Assuming that the market exactly meets the 2022, 2023, and 2024 standards, this is 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 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. 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). 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 net result could be a total carryover RIN bank larger or smaller than 1.83 billion RINs.

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 propose for 2023–2025 (including the 2023 supplemental volume). Doing so would be equivalent to intentionally drawing down the carryover RIN bank in setting those volume requirements. We do not believe that this would be appropriate. In reaching this proposed determination, we considered the functions of the carryover RIN bank, its projected size, the uncertainties associated with its projection, its potential impact on the production and use of renewable fuel, the ability and need for obligated parties to draw on it to comply with their obligations (both on an individual basis and on a market-wide basis), and the impacts of drawing it down on obligated parties and the fuels market more broadly. As previously described, the bank of carryover RINs provides 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 bank of carryover RINs for important programmatic functions, is appropriate when EPA exercises its discretion under its statutory authorities.

Furthermore, 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 believe that the market can make sufficient renewable fuel available to meet the 2022 standards, there may be some challenges, and carryover RINs will be available for those obligated parties who choose to use them for compliance.[91] In addition, in this action we are for the first time proposing to establish volume requirements for three years prospectively. 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 carryover RIN bank could lead to significant deficit carryovers and non-compliance 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 proposing to include carryover RINs in the candidate volumes, nor to set the 2023, 2024, and 2025 volume requirements (including the 2023 supplemental standard) at levels that would intentionally draw down the bank of carryover RINs.

We are not determining that 1.83 billion RINs is a bright-line threshold for the number of carryover RINs that provides sufficient market liquidity and allows the carryover RIN bank to play its important programmatic functions. As in past years, we are instead evaluating, on a case-by-case basis, the size of the carryover RIN bank 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 an even larger carryover RIN bank 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 which we believe represent achievable levels of supply (domestic production and/or import) and consumption.

[89] 79 FR 49793–95 (August 15, 2013).

[90] The calculations performed to estimate the size of the carryover RIN bank can be found in the memorandum, ''Carryover RIN Bank Calculations for 2023–2025 Proposed Rule,'' available in the docket for this action.

[91] 87 FR 39600 (July 1, 2022).

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

[Million RINs] [a]

	2023	2024	2025
Cellulosic biofuel (D3 & D7)	719	1,419	2,131
Biomass-based diesel (D4)	5,389	5,689	5,760
Other advanced biofuel (D5)	256	256	256
Conventional renewable fuel (D6)	14,455	14,505	14,534

[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 DRIA. In Section VI, we discuss our proposed volumes based on a consideration of all of the factors that we analyzed.

Note that the volumes shown in Table III.C.5–1 represent the total candidate volumes consumed 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 consumed in fulfillment of 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. The volume requirements that we are proposing to establish for 2023–2025, in contrast, are based not only on an analysis of the supply-related factors as discussed at the beginning of this Section III, but also on a consideration of the other factors that we analyzed as required by the statute. Below is a summary of the candidate volumes. Section VI provides more comprehensive discussion of our consideration of all factors leading to our determination of the proposed volume targets.

TABLE III.C.5–2—CANDIDATE VOLUMES

[Million RINs] [a]

	2023	2024	2025
Cellulosic biofuel	719	1,419	2,131
Non-cellulosic advanced biofuel [b]	5,100	5,200	5,300
Advanced biofuel	5,819	6,619	7,431
Conventional renewable fuel [b]	[a] 15,000	15,250	15,250
Total renewable fuel	20,819	21,869	22,681

[a] Does not include the 250 million gallon supplemental volume requirement to address the 2016 remand under *ACE*.
[b] These are implied volume requirements, not regulatory volume requirements.

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 use 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 below, we are not using to assess all 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.'' In the final rule establishing the standards for 2020–2022, we indicated that a No RFS baseline would be preferable to using a previous year's volume requirements as the baseline, but that we could not develop such a baseline in the time available for that action.[92]

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

[92] See 87 FR 39600, 39626 (July 1, 2022). See also, ''Renewable Fuel Standard (RFS) Program: RFS Annual Rules—Regulatory Impact Analysis'' at 50, EPA–420–R–22–008, June 2022.

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 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, current, and perceived future economics of the biofuel market when deciding whether to fund the construction of biofuel plants, and our analysis attempted to account for these factors.

The economic analysis for 2023–2025 compares the biofuel value 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. 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. 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 consumers (society at large). 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 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 10 percent after-tax rate of return more typical for industry investment instead of the 7 percent before-tax 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 are forced to 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 discussion in DRIA Chapter 2.

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 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. For instance, 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. 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 and/or state grant programs such as USDA's Higher Blends Infrastructure Incentive Program (HBIIP).

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. Thus, to smooth out the swings in the economics for using biodiesel and renewable diesel and look at it the way 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 a four year period. As a result, the first year modeled 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 below in Table III.D.1–1. A more complete description of the No RFS baseline and its derivation is provided in DRIA Chapter 2.

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

[Million RINs]

	2023	2024	2025
Cellulosic biofuel (D3 & D7)	356	385	417
Biomass-based diesel (D4)	1,374	1,374	1,374
Other advanced biofuel (D5)	216	216	216
Conventional renewable fuel (D6)	13,750	13,730	13,693

Our analysis shows that corn ethanol is economical to use up to the E10 blendwall 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. 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. There would be no renewable electricity used as transportation fuel under a No RFS baseline since we are proposing to establish the eRIN program through this action. However, we expect that the biogas used to produce that renewable electricity would still be produced under a No RFS baseline as discussed in DRIA Chapter 2.1.

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 neglects 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.[93] 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 Volume Requirements

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.[94]

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 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. For this proposed rule for 2023–2025, we again believe that the No RFS baseline is preferable and should be used since it is now available. As a result, we have not used the 2022 volume requirements as a baseline to estimate all of the impacts of the candidate volumes for 2023–2025. However, as an additional informational case, we have estimated the costs alone with respect to the 2022 volume requirements in order to allow comparison to the analysis and results presented in recent annual rules. For this purpose, we needed to estimate a mix of biofuels and associated feedstocks that would represent a reasonable way that the market will respond to the finalized 2022 volume requirements. This assessment is provided in the DRIA in Chapter 2.

[93] 75 FR 14670 (March 26, 2010).

[94] 87 FR 39600 (July 1, 2022).

4. Previous Year Actual Consumption

In most annual standard-setting rules, we have used the previous year's volume requirements as the baseline against which the impacts of the next year's volume requirements would be assessed. In the final rule establishing the volume requirements and percentage standards for 2021 and 2022, however, we instead used the actual consumption in 2020 as a baseline for the purposes of estimating the impacts of those standards. We did this because the previous year's (2020) volume requirements were revised in that same action to represent actual consumption in that year. That approach was also consistent with the approach we took in the rulemaking which established the volume requirements for 2014, 2015, and 2016.[95] 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.[96]

We acknowledge that actual consumption in a previous year would have the advantage that the mix of biofuel types and associated feedstocks are known and would not need to be estimated as would be required when using the previous year's volume requirements as a baseline. However, we have not used the previous year's actual consumption as a baseline in this action because, as explained earlier, we believe that the No RFS baseline is superior. Moreover, the use of actual consumption from a previous year has the drawback that the resulting comparison would conflate the impacts of the program with whatever unique market circumstances existed in that previous year.

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.4–1) 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 DRIA 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.

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)	363	1,034	1,714
Biomass-Based Diesel (D4)	4,015	4,315	4,386
Other Advanced Biofuel (D5)	40	40	40
Conventional Renewable Fuel (D6)	706	776	840

Note that the change in cellulosic biofuel shown in the table above for 2024 and 2025 is primarily due to the increased use of biogas for electricity. Moreover, these values represent changes in the use of cellulosic biofuel in the transportation sector, not changes in the production of cellulosic biofuel. For renewable electricity in particular, we project that there will be no change in production in the 2023–2025 timeframe as a result of the standards we set. Instead, renewable electricity that is already generated will shift from general distribution on the grid to use as a transportation fuel. As described in more detail in DRIA Chapter 3, we took this distinction into account in our analysis of the impacts of the candidate volumes.

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 DRIA. 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.5–2 for the candidate volumes, and Table III.E–1 for the corresponding volume changes in comparison to the No RFS baseline), along with some implications of those analyses. In Section VI we provide our consideration of all factors in determining the volume requirement that we believe would be appropriate for 2023–2025.

A. Climate Change

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,[97] and GHG emissions contribute to climate change,[98] so we believe it is reasonable to use lifecycle GHG emissions

[95] 80 FR 77420 (December 14, 2015).

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

[97] 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.'').

[98] 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)).

estimates as a proxy for climate change impacts.

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, while cellulosic biofuel is required to have lifecycle emissions at least 60 percent less than the baseline fuels. Congress also allowed for facilities that existed or were under construction when EISA was passed to be grandfathered into the RFS program and exempt from the lifecycle GHG emission reduction requirements.

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 in general and crop-based biofuels in particular. New models have been developed to evaluate biofuels and more models—developed for other purposes—have been modified to evaluate the GHG emissions associated with biofuel production and use. There has also been rapid growth in available data on land use, farming practices, crude oil extraction and many other relevant factors. 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 an updated framework is needed. In this rulemaking, EPA is not proposing to reopen the related aspects of the 2010 RFS2 rule or any prior EPA lifecycle greenhouse gas analyses, methodologies, or actions. That is beyond the scope of this rulemaking. However, EPA has initiated work to develop a revised modeling framework of the GHG impacts associated with biofuels. We intend to present the results of a model comparison exercise in the final rulemaking as an initial step in this update to our modeling framework. As an interim step in the process, for this proposed rule, we present biofuel LCA estimates from the range of published values from the scientific/technical literature.

Our assessment of the climate change impacts of the candidate volumes relies on an extrapolation of lifecycle GHG analyses. As we did in the 2020–2022 RVO rulemaking, this approach involves multiplying lifecycle emissions of individual fuels by the change in the candidate volumes 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. In the 2020–2022 RVO rulemaking, we applied the LCA estimates that we developed in the March 2010 RFS2 rule (75 FR 14670) and in subsequent agency actions. In this rulemaking, we are updating our approach to use a range of LCA estimates that are in the literature. Instead of providing one estimate of the GHG impacts of each candidate volume, we provide a high and low estimate of the potential GHG impacts, which is inclusive of the values we estimated in the 2010 RFS final rule and subsequent agency actions. We then use this range of values for considering the GHG impacts of the candidate renewable fuel volumes that change relative to the No RFS baseline described and developed in Section III.

As described in more detail in the DRIA, to develop the new range of LCA values, we conducted a high-level review of relevant literature for the biofuel pathways (combination of biofuel type, feedstock, and production process) that would be most likely to satisfy the candidate renewable fuel volumes. Our literature review was broad and includes studies that estimate the lifecycle GHG emissions associated with the relevant biofuel pathways and the petroleum-based fuels they replace. Our compilation includes journal articles, major reports and studies that inform biofuel-related policies. We included studies that were published after the March 2010 RFS2 rule, as that rule considered the available science at the time. In cases where there were multiple studies that include updates to the same general model and approach, we included only the most recent study. However, we include a subset of older estimates that are still used for particular regulatory programs or that continue to be widely cited for other reasons. We focused on estimates of the average type of each fuel produced in the United States.[99] 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.[100] Some of the studies included estimate lifecycle GHG emissions whereas others only estimate land use change GHG emissions. For purposes of developing a quantitative range of estimates of the overall GHG impacts of the candidate volumes in the DRIA, we relied only on the available LCA estimates; however, our qualitative discussion includes a review of the literature that covers only land use change estimates.

The range of values in the literature for different types of renewable fuels varies considerably, particularly for crop-based biofuels. The ranges of estimates for non-crop based biofuel pathways are narrower relative to the crop-based pathways (See Table IV.A–1). Based on our literature review we can also make some general observations about what contributes to lower and higher GHG estimates. For crop-based biofuels, higher GHG estimates tend to be associated with assessments that show greater land use change emissions, assumed higher levels of energy and fertilizer use for feedstock production, and more intensive energy use for biofuel production. Lower GHG emissions are generally characterized by improvements in technology over time lower land use change emissions (*e.g.,* estimates that include more intensive use of existing agricultural land through double-cropping and other practices that increase yield without bringing more land into production), widespread

[99] 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 widely 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.

[100] 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.

adoption of agricultural practices intended to maintain soil carbon (*e.g.,* cover crops), and the trend toward more efficient biofuel production practices. Consistent with our prior estimates, our literature compilation also suggests that biofuels produced from byproducts and wastes tend to have lower lifecycle GHG emissions than crop-based biofuels. For example, the GHG estimates for renewable diesel produced from used cooking oil are significantly lower than those for renewable diesel produced from soybean oil. For these non-crop-based pathways, different approaches of accounting for co-products can have a large effect on results, as well as whether pre-existing markets for these feedstocks will be backfilled. An important factor dictating the GHG emissions associated with biogas-to-CNG pathways include the extent of methane leakage during the collection, processing, and transport of renewable natural gas.

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.
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	15 to 58.
Tallow Renewable Diesel	14 to 81.
Distillers Corn Oil Biodiesel	10 to 37.
Distillers Corn Oil Renewable Diesel.	12 to 46.
Natural Gas CNG	72 to 81.
Landfill Gas CNG	9 to 70.
Manure Biogas CNG	−533 to 44.

Our compilation of the current literature reveals a wide range of estimates of the lifecycle GHG emissions associated with renewable fuels. The range of estimates is particularly wide for fuels derived from crop-based feedstocks due to variation in land use change GHG estimates. There is also a wide range of estimates for tallow renewable diesel depending on whether or not the studies allocate GHG emissions from meat production to the tallow or treat it as a byproduct. Estimates for landfill gas and manure biogas CNG vary substantially based on assumptions about methane emissions in the baseline scenario. Given the ongoing uncertainty associated with the science of analyzing biofuel GHG effects, our current assessment of the GHG impacts does not support significantly raising or lowering the candidate volumes derived from the supply-related factors discussed in Section III.

For the final rule, we intend to advance our understanding of the lifecycle GHG emissions associated with changes in crop-based biofuel consumption, including through new modeling of biofuel lifecycle GHG impacts and a comparison of available models for biofuel GHG analysis. In the DRIA we discuss models that have been used since 2010 to estimate biofuel GHG emissions, including the market-mediated indirect emissions associated with increasing the production of crop-based fuels. We intend to run similar scenarios through some of these models and to compare the results. For example, we intend to align the amount of U.S. biofuel consumption in a reference scenario and use the models to estimate the GHG emissions associated with scenarios that include an increased volume of corn ethanol and separately an increased volume of soybean oil biodiesel. We also intend to compare key input assumptions used in the models, and time permitting, align some of these assumptions.

We believe the model comparison exercise will provide valuable information about the capabilities of these models, and the effects of model choice and key input assumptions on biofuel lifecycle GHG estimates. While this model comparison exercise can provide helpful information for the final rule, we recognize that crop-based biofuel lifecycle GHG emissions are inherently uncertain to a large degree. Thus, we do not expect this exercise to produce a single robust estimate of the GHG impacts associated with the volume requirements that will be established with the final rule. However, we do expect this model comparison exercise to advance our understanding for the final rule, by more precisely locating the reasons that model estimates differ, and by identifying future priorities for updating and aligning particular assumptions across the models.

We invite comment on the range of lifecycle GHG emissions impacts of the biofuels considered as part of this proposed rulemaking, and input on the proposed approach, or other potential approaches, for conducting a model comparison exercise for the final rule. We invite comment on the scope of this review as well as comment on the specific studies included in the review. We also invite comment on how this information may be used to inform the final rule. Given the different types of modeling frameworks currently available, we also invite comments on the appropriateness of these different approaches for conducting lifecycle GHG emissions analysis and whether model results can or should be weighted if we choose a multi-model approach to assessing GHG emissions for purposes of RFS volumes assessment. Since models treat time differently (*e.g.,* different time steps, static versus dynamic models), we invite comment on the most appropriate way to handle the GHG impacts of biofuels over time. As we undertake this expanded examination of the changes in GHG emissions attributable to biofuels and the RFS program, we solicit input on how we should refine our analysis by revising or incorporating various effects such as land use change, the effectiveness of conservation programs targeted at soil sequestration of carbon, international leakage (*e.g.,* effects of potentially backfilling vegetable oil feedstocks with palm oil), facility-level variability in GHG emissions, and others. We also request comment on how we can incorporate new research that examines the effectiveness of the RFS program in mitigating GHG emissions.

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 imports of petroleum, which in turn would have a direct impact on 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 independence and energy security are distinct but related

concepts.[101] The goal of U.S. energy independence is the elimination of all U.S. imports of petroleum and other foreign sources of energy.[102] U.S. energy security is broadly defined as the continued availability of energy sources at an acceptable price.[103] Most discussions of U.S. energy security revolve around the topic of the economic costs of U.S. dependence on oil imports.

The U.S.'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.[104] Domestic oil consumption in 2022 returned to pre-COVID–19 levels and is expected to be relatively steady during the timeframe of this proposed rule, 2023–2025. The U.S. has increased its production of oil, particularly ''tight'' (*i.e.,* shale) oil, over the last decade.[105] 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 proposed rule, 2023–2025.[106] [107] This is a significant reversal of the U.S.'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.[108]

More recently, in the beginning of 2022, world oil prices have risen fairly rapidly. For example, as of January 3, 2022, the West Texas Intermediate (WTI) crude oil price was roughly $76 per barrel. The WTI oil price increased to roughly $124 per barrel on March 8th, 2022, a 63 percent increase.[109] High and volatile oil prices in 2022 are a result of a combination of several factors: supply not rising fast enough to meet rebounding world oil demand from increased economic activity as COVID–19 recedes, reduced supply from some leading oil-producing nations, and geopolitical events/conflicts (*i.e.,* war in Ukraine). It is not clear to what extent the current oil price volatility will continue, increase, or be transitory in the 2023–2025 period addressed by this proposed 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 from potentially unstable regions of the world. 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).[110]

For this proposed 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.[111] 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 proposed 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 2022 Annual Energy Outlook.[112] 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 the DRIA accompanying this proposal.

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 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 crude oil imports/U.S. petroleum product imports from the candidate volumes is provided in the DRIA. Table IV.B–1 below presents the macroeconomic oil security premiums and the total energy security benefits for the candidate volumes for 2023–2025.

[101] Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? Energy Policy 38, pp. 1614–1621.

[102] Ibid.

[103] Ibid.

[104] U.S. Energy Information Administration. 2022. Total Energy. *Monthly Energy Review.* Table 3.1. Petroleum Overview. March.

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

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

[107] U.S. Energy Information Administration. 2022. *Annual Energy Outlook* 2022. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

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

[109] U.S. Energy Information Administration daily spot prices, available at: *https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.*

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

[111] See the DRIA for more discussion of EPA's assessment of monopsony impacts of this proposed 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.

[112] See DRIA 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.

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

Year	Macroeconomic oil security premiums (2021$/barrel of reduced imports)	Total energy security benefits (millions 2021$)
2023 (Including the supplemental standard)	$3.37 ($0.88–$6.20)	$211 ($55–$389)
2023 (Excluding the supplemental standard)	$3.37 ($0.88–$6.20)	$200 ($52–$368)
2024	$3.46 ($0.89–$6.36)	$219 ($56–$403)
2025	$3.46 ($0.83–$6.40)	$223 ($53–$412)

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

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.C.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 DRIA Chapter 9.

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, of which the biofuel feedstock usually is 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.
- 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.
- 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 which is reflected in the relative fossil fuel volume being displaced.

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.

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. A detailed discussion of the renewable fuel costs relative to the fossil fuel costs is contained in DRIA Chapter 10.

For each year for which we are proposing 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.

This rulemaking includes proposed regulatory provisions that would govern the generation of RINs from renewable electricity (eRINs) generated from biogas (see Section VIII). Because there is a substantial quantity of biogas already being used to generate electricity today, and there is a limited number of electricity-powered vehicles projected to be in the light-duty vehicle fleet through 2025, we determined that existing biogas to electricity generation would be sufficient to supply light-duty vehicles. As a result, the RFS program would not drive any new biogas-based electricity production through 2025 and as a consequence there would be no biogas-to-electricity production costs. Nevertheless, since biogas to electricity will be a new aspect of the RFS program, the sunk cost of using biogas to produce electricity is estimated and presented in the RIA Chapter.

TABLE IV.C.2–1—TOTAL SOCIAL COSTS

[Million 2021 dollars] [a]

	2023	2023 with supplemental standard	2024	2025
Gasoline	252	252	258	303

TABLE IV.C.2–1—TOTAL SOCIAL COSTS—Continued

[Million 2021 dollars] [a]

	2023	2023 with supplemental standard	2024	2025
Diesel	10,855	11,512	8,919	8,651
Natural Gas	92	92	119	148
Total	11,119	11,856	9,295	9,100

[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

[2021 dollars]

	Units	2023	2023 with supplemental standard	2024	2025
Gasoline	¢/gal	0.18	0.18	0.18	0.22
Diesel	¢/gal	19.6	20.7	16.2	15.6
Natural Gas	¢/thousand ft^3	0.30	0.30	0.39	0.48
Gasoline and Diesel	¢/gal	5.7	6.1	4.8	4.7

[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.

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. Despite increasing renewable diesel fuel volumes over the 2023 to 2025 year timeframe, the projected cost to diesel fuel for the increased renewable diesel volume is decreasing due to year-over-year decreases in projected vegetable oil prices which in turn decreases the relative cost of renewable diesel. However, as described more fully in DRIA 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 proposed 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 DRIA Chapter 10.5. Table IV.C.3–1 summarizes the estimated impacts of the candidate volumes on gasoline, diesel, and natural gas fuel prices at retail when the costs of each biofuel is amortized over the fossil fuel it displaces. In the final row of the table, we show the estimated retail costs when the total costs are amortized evenly over the entire gasoline and diesel fuel pools since these are the obligated fuel pools.

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

[¢/gal]

	2023	2024	2025
Relative to No RFS Baseline:			
Gasoline	0.6	1.8	3.1
Diesel	14.1	14.4	14.9
Gasoline and Diesel	4.3	5.3	6.3
Relative to 2022 Baseline:			
Gasoline	1.7	2.6	3.3
Diesel	0.8	1.5	3.2
Gasoline and Diesel	1.4	2.3	3.3

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 14.9¢ per gallon for diesel fuel in 2025.

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.[113] Applying the price correlation from the USDA study would indicate that the 14.9¢ per gallon diesel fuel cost increment associated with the 2025 RFS volumes which increases retail prices by about 5.1 percent, would then increase the wholesale price of produce by about 1.18 percent. If produce being transported by a diesel truck costs $3 per pound, the increase in that product's price would be $0.035 per pound.[114] If all the estimated program subsidized costs are averaged over the combined gasoline and diesel fuel pool as shown in the bottom row of Table IV.C.3–1, the impact on produce prices would be proportionally lower based on the lower per-gallon cost.

D. Comparison of Costs and Impacts

As explained in Section III of this rule, the statutory factors for which the potential impacts of the candidate volumes are reasonably quantifiable are compared against a No RFS baseline, which assumes the RFS program remains intact through 2022 but ceases to exist thereafter. The statute does not specify how EPA should assess each factor, 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.[115] Information and specifics on how fuel costs are calculated are presented in DRIA Chapter 9, while energy security benefits are discussed in DRIA Chapter 4. A summary of the fuel costs and energy security benefits is shown in Tables IV.D–1 and 2. 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 DRIA. 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. We request comment on our assessment of these factors and methods that could be used to quantify the impact of the RFS on these factors in future actions.

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

[2021 Dollars, millions] [a]

Year	Discount rate		
	0%	3%	7%
2023:			
Excluding Supplemental Standard	11,199	11,199	11,199
Including Supplemental Standard	11,856	11,856	11,856
2024	9,295	9,025	8,687
2025	9,100	8,578	7,948
Cumulative Discounted Costs:			
Excluding Supplemental Standard	.....	28,801	27,835
Including Supplemental Standard	.....	29,458	28,492

[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 CANDIDATE VOLUMES

[2021 Dollars, millions]

Year	Discount rate		
	0%	3%	7%
2023:			
Excluding Supplemental Standard	200	200	200
Including Supplemental Standard	211	211	211
2024	219	213	205
2025	223	210	195
Cumulative Discounted Benefits:			
Excluding Supplemental Standard	.....	623	600
Including Supplemental Standard	.....	634	611

Regardless of whether or not we were able to quantify or monetize the impact of the candidate volumes on each of the statutory factors, consideration of these factors is still required by the statute. We request comment generally on how costs and benefits quantified in this proposed rule are calculated and accounted for, as well as methods to quantify and monetize additional statutory factors where appropriate.

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. However, Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to

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

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

[115] Due to the uncertainty related to the GHG emission impacts of the candidate volumes (discussed in further detail in Chapter 3.2 of the RIA) we have not included a quantified projection of the GHG emission impacts in this proposal.

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 minority populations and low-income populations 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.[1] 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 minority populations, low-income populations, tribes, and/or indigenous peoples, 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 then 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, the Agency 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.[116] [117] [118] [119] 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.[120] 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.[121] [122] [123] 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, NO_X, CO, SO_2 and air toxics, occur during the production, storage, transport, distribution, and combustion of petroleum-based fuels and biofuels.[124] 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.[125]

DRIA Chapter 4.1 summarizes what is known about potential air quality impacts of the candidate volumes assessed for this rule. We expect that

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

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

[118] 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.*

[119] 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.*

[120] 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.

[121] 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.

[122] 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.

[123] 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.

[124] U.S. EPA (2022) Health and environmental effects of pollutants discussed in chapter 4 of draft regulatory impact analysis (DRIA) supporting proposed RFS standards for 2023–2025. Memorandum from Rich Cook to Docket No. EPA–HQ–OAR–2021–0427, July 21, 2022.

[125] 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.*

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 magnitude and direction of travel of facility-specific emissions associated with the candidate volumes, and therefore we are unable to evaluate impacts on air quality in the specific EJ communities 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 DRIA 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 registered biofuel facilities and within 5 kilometers of petroleum refineries to identify any disproportionate impacts these volume changes may have on nearby minority or low-income populations.[126] Information on these populations and potential impacts upon them are further discussed in DRIA 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 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 facilities are in sparsely populated areas or have lower impacts on air quality. RNG or biogas electricity 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 require greater production of corn ethanol or biogas electricity than exists already, and therefore we would not expect any adverse impacts on EJ communities near biogas facilities that upgrade to RNG nor to biogas facilities combusting on site for electricity generation during the timeframe of this rule.

2. Other Environmental Impacts

As discussed in DRIA 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, as a result, soil quality, which could in turn have disproportionate impacts on communities of concern. This does not apply to biogas used to produce electricity or upgraded to RNG, since while land use impacts from agriculture, waste management, and wastewater treatment may impact water and soil quality on their own, biogas feedstock capture is a net benefit to soil and water quality, as it captures otherwise wasted product. At this time, we are not able to assess any contributions to these potential effects from biofuels apart from biogas. To better understand the relationship between the annual RFS volume requirements and air, water and soil quality issues that may impact EJ communities, we seek comment on additional information on the impacted populations in order to evaluate any environmental justice concerns associated with the candidate volumes. We seek comment on the following:

- Where are the populations that are currently being impacted to the greatest degree?
- Who resides in those areas?
- How are resident populations using the water and soil?
- How are the changes in water quality and availability impacting those uses and, thereby, those populations?

3. Economic Impacts

The candidate volumes could have an impact on food and fuel prices nationwide, as discussed in DRIA Chapters 8.5. We estimate that the candidate volumes would result in food prices that are 0.57 percent higher in 2023 and 2024 and 0.58 percent higher in 2025, that the food prices we project with the No RFS baseline. 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 as shown in Table IV.E.3–1. We request comment on these estimates of the impacts of the candidate volumes on food prices, and the methodology used to derive these estimates.

TABLE IV.E.3–1—PROPORTION OF TOTAL EXPENDITURES ON FOOD AND FUEL [127]

	All consumer units	Lowest 20% consumer income	Second-lowest 20% consumer income
Total expenditures	$61,350	$28,782	$39,846
Food expenditures	$7,316	$4,095	$5,380
Percent of total expenditures on food	11.9%	14.3%	13.5%
Fuel expenditures	$1,568	$814	$1,254
Percent of total expenditures on fuel	2.6%	2.8%	3.1%
Percent Women	53%	65%	56%
Percent Black	13%	19%	15%

[126] 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.

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

TABLE IV.E.3–1—PROPORTION OF TOTAL EXPENDITURES ON FOOD AND FUEL [127]—Continued

	All consumer units	Lowest 20% consumer income	Second-lowest 20% consumer income
Percent With a High School Degree or Less	30%	49%	41%

V. Response to Remand of 2016 Rulemaking

In this action, we are proposing to complete 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*.[128] [129] As discussed in the final rule establishing applicable standards for 2020–2022,[130] our intended 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.[131] We required the first 250-million-gallon supplement in 2022. We are now proposing a second 250-million-gallon supplement to be complied with in 2023. This 2023 supplemental volume requirement, if finalized, in combination with the 2022 supplement would constitute a meaningful remedy and complete 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.[132] We also discussed our consideration of alternative approaches to respond to the remand.[133] We maintain the same views on the alternatives discussed in that rulemaking, including those identified by commenters, and in the intervening period of time 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. This section will therefore only provide a short summary of the appropriateness of the proposed 2023 supplement, as well as how it would be implemented.

A. Supplemental 2023 Standard

We are proposing to complete 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 would thus avoid the difficulties associated with reopening 2016 compliance, as discussed in detail in the 2020–2022 proposed rulemaking.[134] This supplemental standard will have 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 will provide a meaningful remedy in response to the court's vacatur and remand in *ACE* and will effectuate 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. It is with emphasis on these considerations that we are proposing a different approach from the one proposed in the 2020 proposal.[135] 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 any 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 will 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,[136] and obligated parties had an opportunity at that time to utilize those RINs for compliance or sell them to other parties, while ''banking'' RINs that could be utilized for future compliance years.

In applying a supplemental standard to 2023, we would treat 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 would also be subject to the supplemental standard. The applicable deadlines for attest engagements and compliance demonstrations that apply to the 2023 standards would also apply to the supplemental standard. The gasoline and diesel volumes used by obligated parties to calculate their obligation would be their 2023 gasoline and diesel production or importation. Additionally, obligated parties could use 2022 RINs for up to 20 percent of their 2023 supplemental standard.

[128] 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).

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

[130] 87 FR 39600, 39627–39631 (July 1, 2022).

[131] 864 F.3d at 691.

[132] 87 FR 39600, 39627–39628 (July 1, 2022).

[133] 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.

[134] 86 FR 72436, 72459–72460 (Dec. 21, 2022).

[135] See *FCC* v. *Fox,* 556 U.S. 502 (2009), acknowledging an agency's ability to change policy direction.

[136] 2016 RINs could also be used for up to 20 percent of an obligated party's 2017 compliance demonstrations.

We seek comment on this approach of applying a supplemental standard for 2023 associated with the *ACE* remand on top of the proposed standards for 2023.

1. Demonstrating Compliance With the 2023 Supplemental Standard

As we have done for the 2022 supplemental standard, we are proposing to prescribe formats and procedures as specified in 40 CFR 80.1451(j) for how obligated parties would demonstrate compliance with the 2023 supplemental standard that simplifies the process in this unique circumstance. Although the proposed 2023 supplemental standard would be a regulatory requirement separate from and in addition to the 2023 total renewable fuel standard, obligated parties would submit a single annual compliance report for both the 2023 annual standards and the supplemental standard and would only report a single number for their total renewable fuel obligation in the 2023 annual compliance report. Obligated parties would 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 unique compliance situation, we would issue guidance with instructions on how to calculate and report the values to be submitted in their 2023 compliance reports.

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 designed to address the approach that we are proposing in this action, namely the use of a 2016 volume requirement to calculate a 2023 percentage standard. Nonetheless, we can apply the same general approach to calculating a supplemental percentage standard for 2023.

If this proposed approach to the *ACE* remand is finalized, the numerator in the formula in 40 CFR 80.1405(c) would be the supplemental volume of 250 million gallons of total renewable fuel. The values in the denominator would remain the same as those used to calculate the proposed 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 would be 0.14 percent.

The proposed supplemental standard for 2023 would be a requirement for obligated parties separate from and in addition to the 2023 standard for total renewable fuel. The two percentage standards would be listed separately in the regulations at 40 CFR 80.1405(a), but in practice obligated parties would 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 the 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.'' 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 were only providing a partial response to the court's remand and vacatur. This proposed action, if finalized, would complete our response. Additionally, as we have in the past, we propose to rely on our authority in CAA section 211(o)(2)(A)(i) to promulgate late standards.[137] CAA section 211(o)(2)(A)(i) requires that EPA ''ensure'' that ''at least'' the applicable volumes ''are met.''[138] 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 in 2023, as we are proposing in this action.

As noted elsewhere, we will not finalize this action prior to the beginning of the 2023 compliance year. Thus, our action is partly retroactive. In analyzing the benefits and burdens attendant to this approach, we have also considered the partially retroactive nature of the rule.

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.[139] EPA must consider and mitigate the burdens on obligated parties associated with a delayed rulemaking.[140] 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.[141] The approach we are proposing in this action would implement 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 retroactive standard on obligated parties, but because obligated parties would comply with the proposed supplemental standard in 2023, it would instead be a late standard applied in 2023, with partially retroactive effects. Pursuant to

[137] 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 7545(o)(2). 75 FR 14670, 14718.

[138] 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.''

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

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

[141] *NPRA,* 630 F.3d at 154–58.

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.

We believe that the approach proposed in this action, if finalized, could provide benefits that outweigh potential burdens. Consistent with the 2016 renewable fuel volume requirement established by Congress, our proposed and intended 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 would provide 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 that while the additional volume in 2023 will put 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. We are soliciting comment on the feasibility of the proposed 250-million-gallon supplemental standard in 2023. As explained earlier, there are insufficient 2015 and 2016 RINs available to satisfy the proposed 250-million-gallon volume requirement. Instead, we are proposing a supplemental volume requirement to the 2023 standards that will apply prospectively. Doing so would allow 2022 and 2023 RINs to be used for compliance with the 2023 supplemental standard, in keeping with existing RFS regulations. We believe there would 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. We believe that compliance through the use of carryover RINs would not be necessary, but nevertheless would remain available as an option for obligated parties for compliance.[142]

Second, we provide significant lead-time for obligated parties by proposing this supplemental standard for 2023 no less than 18 months prior to the 2023 compliance deadline.[143] Moreover, we initially provided obligated parties notice of the 250-million-gallon supplemental standard for 2022 in December of 2021,[144] no less than 18 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 actual 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.

Third, we are proposing 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 will be a supplement to the 2023 standards. This approach would not only allow the use of 2022 and 2023 RINs for compliance with the 2023 standard, as described earlier, but it would also avoid 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, our proposal allows obligated parties to satisfy both the 2023 standards and the supplemental standard in a single set of compliance and attest engagement demonstrations. We are also proposing to extend 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 proposed 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.[145]

Lastly, we carefully considered alternatives, including retaining the 2016 total renewable fuel volume as described in the 2020 proposal,[146] reopening 2016 compliance and applying a supplemental standard to the 2016 compliance year,[147] 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.[148]

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 would be 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. We seek comment on this approach, as well as other alternative approaches to fully address the remand.

[142] See Section IV.F for further discussion of the carryover RIN bank.

[143] See 40 CFR 80.1427.

[144] 86 FR 72436 (December 21, 2021).

[145] 87 FR 39600 (July 1, 2022).

[146] 84 FR 36762, 36787–36789 (July 29, 2019).

[147] 86 FR 72459.

[148] 87 FR 39600 (July 1, 2022). See also Response to Comments document, Chapter 8.

VI. Proposed 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.[149] As described in Section III, we did this by first deriving a set of ''candidate volumes'' using several supply-related 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 DRIA. 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 proposal. We intend to consider the best available information and science, including information provided through comments and any other information that becomes available, when setting the volume requirements in the final rule.

In this section, we summarize and discuss the implications of all our analyses as they apply 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 would be equal to the sum of cellulosic biofuel and non-cellulosic advanced biofuel, while the volume requirement for total renewable fuel would be equal to the sum of advanced biofuel and conventional renewable fuel.[150]

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 delegate to EPA the discretion to decide how and at what level of specificity to analyze the statutory factors. This section 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 them 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, we remain 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 proposing 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 the EISA.

As discussed in Section VIII.A, EPA determined that electricity may, under certain circumstances, qualify as a renewable fuel in the RFS2 rulemaking in 2010,[151] and in the 2014 Pathways II rule we promulgated a pathway for the generation of D3 RINs for renewable electricity produced from biogas (eRINs).[152] However, it subsequently became apparent that our regulations were not set up to appropriately enable the generation of eRINs under the RFS program. With this action we are proposing to not only revise the existing eRIN regulations, but to also include the cellulosic biofuel volumes that would result from allowing for the generation of RINs for renewable electricity from biogas under the program. Under this proposal, generation of eRINs would first begin in 2024.

As discussed in Section III.B.1, we developed candidate volumes for cellulosic biofuel based on a consideration of 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 electric vehicles in the fleet) and of the availability of qualifying feedstocks, primarily but not exclusively biogas. With an eye towards estimating candidate volumes which represent levels that can be achieved but which would not need to be waived under the cellulosic waiver authority (per CAA 211(o)(2)(B)(iv)), we estimated the following:

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

[Million RINs]

	2023	2024	2025
Liquid Cellulosic Biofuel	0	5	10
CNG/LNG Derived from Biogas	719	814	921
eRINs	0	600	1,200
Total Cellulosic Biofuel	719	1,419	2,131

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

[150] 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.

[151] 75 FR 14670 (March 26, 2010).

[152] 79 FR 42128 (July 18, 2014).

We then analyzed these candidate volumes according to the other statutory factors. 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.[153] 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 and electricity) 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, 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.[154] 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.

Despite this similarity, there are also significant differences between liquid cellulosic biofuels and CNG/LNG or electricity derived from biogas. In particular, the cost of producing liquid cellulosic biofuel is 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.

Cellulosic biofuels derived from biogas, most notably CNG/LNG and renewable electricity, are also generally produced from waste materials or residues (*e.g.,* through biogas collection from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters) and thus are also not expected to affect the conversion of wetlands, ecosystems and wildlife habitat, soil and water quality, the price and supply of agricultural commodities, and food prices. However, in contrast to the feedstocks generally used to produce liquid cellulosic biofuels, significant quantities of biogas from these sources are already used to produce electricity, while smaller quantities are injected into natural gas pipelines.[155] In some situations, such as at larger landfills, CNG/LNG derived from biogas may also be able to be produced at a price comparable to fossil natural gas. Because of the relatively low cost of production, biogas is expected to remain as the dominant feedstock for cellulosic biofuel through 2025, continuing to expand its use as CNG/LNG as well as its use to generate renewable electricity.

Despite the relatively low cost of production for CNG/LNG and electricity derived from biogas, the combination of the high cellulosic biofuel RIN price and the significant volume potential for CNG/LNG and renewable electricity 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 $0.03 per gallon in 2025.[156] eRINs alone are projected to increase the price of gasoline and diesel by $0.01 per gallon in 2024 and approximately $0.02 per gallon in 2025.[157]

Based on our analyses of all of the statutory factors, we believe that the candidate volumes shown in Table VI.A–1 would be reasonable and appropriate to require. As a result, in this action we are proposing cellulosic biofuel volume requirements through 2025 at the levels that we project will be produced in the U.S. or imported in each year and used as transportation fuel. Starting in 2024 the proposed volumes would also include RINs generated for renewable electricity used as transportation fuel. The proposed volumes, shown in Table VI.A–2, are generally consistent with the volumes shown in Table VI.A–1, with one minor exception. More recent data suggests that liquid cellulosic biofuel production will be slightly lower than the candidate volumes and we have adjusted the proposed volumes accordingly (3 million ethanol-equivalent gallons in 2024 and 5 million ethanol equivalent gallons in 2025). The proposed increases in the cellulosic biofuel volume relative to previous years reflect the statutory intent to support the development of increasing volumes of cellulosic biofuel as evidenced by the dramatic increases evident in the statutory volume targets in prior years, and the potential for significant GHG reductions that may result.

TABLE VI.A–2—PROPOSED CELLULOSIC BIOFUEL VOLUMES

	2023	2024	2025
Liquid Cellulosic Biofuel	0	3	5
CNG/LNG Derived from Biogas	719	814	921
eRINs	0	600	1,200
Total Cellulosic Biofuel	719	1,417	2,126

The basis for these projections of cellulosic biofuel production is discussed in further detail in DRIA Chapter 6.1. In this chapter we acknowledge that there is significant uncertainty regarding cellulosic biofuel

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

[154] 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.

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

[156] See DRIA Chapter 10 for a further discussion of the expected impact of RINs generated for CNG/LNG or electricity derived from biogas on costs.

[157] See DRIA Chapter 10.5.5.2 for more information on the projected fuel price impacts of eRINs.

production through 2025, particularly for CNG/LNG derived from biogas and for eRINs. For CNG/LNG derived from biogas the primary source of uncertainty is whether future growth in the production of these fuels will more closely resemble the lower growth rates observed in the past two years or whether it will return to the higher rates of growth observed in earlier years prior to the COVID pandemic. For eRINs, the primary sources of uncertainty are related to the sales of electric vehicles through 2025, how quickly electricity generators and OEMS will be able to complete the necessary steps to register under the RFS program, and the rate of participation/registration of these parties through 2025. Alternative projections for CNG/LNG derived from biogas are shown in Table IV.A–3. Further detail on these alternative projections can be found in DRIA Chapter 6.1. We request comment on our projections of cellulosic biofuel production for 2023–2025, including whether our primary projections, the alternative projections, or other projections presented by commenters are more likely in these years. We also welcome any other information or data that would inform our projections of cellulosic biofuel production in 2023–2025.

TABLE VI.A–3—ALTERNATIVE PROJECTIONS OF CNG/LNG DERIVED FROM BIOGAS

[Million ethanol equivalent gallons]

Growth rate time period	Average growth rate (%)	Projected production of CNG/LNG derived from biogas		
		2023	2024	2025
2015–2019	30.4	955.4	1,245.8	1,624.5
2015–2021	26.3	896.2	1,131.9	1,429.7

We recognize that with this proposed Set rule we are beginning 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). We note that there are several important changes in EPA's statutory authority in years after 2022, and we seek input from commenters on how these changes can or should impact the required cellulosic biofuel volumes.

EPA has the authority to establish RFS volumes for multiple years in one action, as we have proposed to do in this rule. We believe that proposing cellulosic biofuel volumes for multiple years (2023–2025) at a level equal to the projected production of cellulosic biofuel in these years will help provide the consistent market signals that the cellulosic biofuel industry needs to develop. We also recognize that there is increased uncertainty in our cellulosic biofuel projections due to the multi-year nature of this proposed rule, the inclusion of regulations governing the generation of eRINs, and the potential for the development and deployment of new cellulosic biofuel production pathways. The inclusion of eRINs in particular significantly increases the uncertainty of our cellulosic biofuel projections for 2024 and 2025. Unlike other types of cellulosic biofuel EPA has no history projecting the generation of eRINs under the RFS program. The number of eRINs generated could also be impacted by a number of interrelated and complex factors, such as the size and future growth rate of the EV fleet, the supply of qualifying biogas for electricity generation, competition for the biogas and electricity from other markets, and the rate at which electricity generators can register to participate in the RFS program. We intend to closely monitor the generation of all cellulosic RINs, including eRINs, in future years and will consider adjusting the cellulosic biofuel volume requirements through a rulemaking or other mechanism if necessary, and we request comment on the impact the inclusion of eRINs in this rule could have on the volatility of the cellulosic RIN price.

At the same time, we also believe that the eRIN proposal provides greater confidence for investments in biogas by creating a new, larger market for the use of biogas as transportation fuel at a time when the production of CNG/LNG derived from biogas may begin to be constrained by the number of CNG/LNG vehicles in the fleet. The significantly higher cellulosic biofuel volumes that we are proposing 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.

In comments on previous RFS annual rules and discussions with EPA staff a number of cellulosic biofuel producers and parties developing cellulosic biofuel production technologies have stated that despite the incentive provided by the RFS program, variability and uncertainty in cellulosic RIN prices and future cellulosic biofuel requirements are hindering the development of the cellulosic biofuel industry.[158] Many of these parties have stated that while uncertainties related to the demand for biofuels created by the RFS program and relatively volatile RIN prices are not unique to cellulosic biofuels, these factors are especially challenging in situations where cellulosic biofuel producers are considering investing in novel technologies that in many cases require significant capital investment. Some of these parties have noted that there is greater uncertainty in projecting cellulosic biofuel volumes in this Set rule relative to previous RFS annual rules, particularly as EPA has stated our intent to include a regulatory structure that would allow for the generation of eRINs for the first time and the fact that in this rule we are projecting cellulosic biofuel for several years rather than just a single year. These parties have 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 higher or lower than the actual production of cellulosic biofuel.

Consequently, these cellulosic biofuel stakeholders have stated that EPA must consider the impacts this potential variability may have on both their industry and obligated parties. In a scenario where cellulosic biofuel production and imports are significantly lower than the cellulosic biofuel volume requirements (a RIN shortfall) there would be insufficient RINs for obligated parties to meet their RFS obligations.

[158] For example, see Letter from Anew, Energy Power Partners, Opal Fuels, DTE Vantage, and Iogen to US EPA. August 26, 2022.

This could result in some obligated parties being forced to carry RFS compliance deficits into future years, and if cellulosic biofuel production and imports continued to fall short of the volume requirements obligated parties could be forced into non-compliance. Alternatively, in a scenario where cellulosic biofuel production and imports are significantly higher than the cellulosic biofuel volumes requirements (a RIN surplus) the price of cellulosic RINs could fall to a level at or approaching the advanced biofuel RIN price. This could negatively impact investment in cellulosic biofuel production, and some stakeholders have argued that even the possibility that this scenario could occur in the future could negatively impact investment.

In discussions with stakeholders, we have identified several existing mechanisms to address a potential cellulosic RIN shortfall should one occur in a future year. For example, we have consistently used our cellulosic waiver authority when necessary to reduce the statutory cellulosic biofuel targets. Consistent with our statutory authority, we have offered cellulosic waiver credits to obligated parties in years we have used our cellulosic waiver authority to reduce the statutory targets. We believe that we retain the ability to use the cellulosic waiver authority to reduce the cellulosic biofuel volumes we are establishing in this rule if necessary via a subsequent rule, and that were we to use this authority we would continue to set the cellulosic volume using a principle of ''taking neutral aim at accuracy.'' In such a scenario EPA would make available cellulosic waiver credits to obligated parties. These existing tools appear sufficient to address any potential RIN shortfalls in a future year. We request comment on the sufficiency of these tools to address a potential RIN shortfall, and other mechanisms that can or should be used to protect obligated parties against the negative impacts of a RIN shortfall.

The RFS program as currently structured also contains a mechanism to help stabilize demand for cellulosic biofuel and cellulosic RINs in the event of a RIN surplus. Obligated parties have the ability to use RINs from the previous compliance year to satisfy up to 20 percent of the current year's obligation. These carryover provisions provide protection for the value of RINs in the event of a RIN surplus, as these RINs can be carried forward and used in the next compliance year. In the event of a surplus of RINs in a current year, the fact that these RINs will still be of value in the following year when RINs may be in short supply helps to stabilize the D3 RIN value over time. The RIN carryover provisions, however, do not eliminate all risk that an oversupply of cellulosic RINs will negatively impact the RIN price. Especially if, for example, the oversupply exceeds the 20 percent carryover limit we would expect to see an impact on the price of cellulosic RINs.

Because of this, a number of cellulosic biofuel producers have communicated to EPA that the existing mechanisms in the RFS regulations to address the negative outcomes that could result from a RIN surplus are insufficient. They have recommended options that EPA could implement to address a potential future RIN surplus that would further protect them against potential RIN price volatility and/or lower RIN prices.[159] Specifically, these parties suggested that EPA could address potential future RIN surpluses through either future rulemakings or an automatic adjustment mechanism established in our regulations. If EPA decided to address any potential future RIN surplus via rulemaking these parties suggested that the rule be completed prior to the start of the compliance year in which it applied (*e.g.,* adjustments to the 2025 cellulosic volume would be completed by November 2024) and that the rule should be limited in scope to only increasing the cellulosic biofuel volume requirement for the upcoming year. The parties suggested that EPA consider whether increasing the cellulosic biofuel volume requirement could be done via a direct final rule or whether such an adjustment would require a full rulemaking. Alternatively, these stakeholders suggested that EPA could include a formula in the Set rule that would authorize EPA to adjust the cellulosic biofuel volume requirement through a public notification if our projection of cellulosic biofuel production and imports, including available carryover RINs, for the coming year exceeded or fell short of the cellulosic biofuel volume requirement by more than an undefined de minimis amount. As an example, stakeholders suggested that EPA could establish cellulosic volumes in the set rule, and notify all stakeholders of our intent to increase or decrease the required volumes to account for carryover RINs in excess of an established threshold or RIN deficits on an annual basis. The stakeholders suggested that including such a formula in the Set rule would allow these adjustments to be made without the need for a rulemaking process.

We acknowledge that either of these mechanisms would likely reduce, and potentially even eliminate, the investment risk associated with a potential surplus of cellulosic RINs causing RIN price volatility or lower RIN prices. However, these options are not without potential challenges. The proponents of these changes to the RFS program acknowledge that regularly adjusting the RFS volume requirements through a rulemaking process would leave market participants exposed to variability in EPA RFS policy perspectives and could re-introduce some level of uncertainty and litigation risk that EPA is hoping to minimize in issuing a multi-year Set rule. They also recognize that changing the required volume of cellulosic biofuel via a direct final rule creates a litigation risk if even a single party opposes the changes. Alternatively, adjusting the cellulosic biofuel volume requirements using a public notice according to a formula in the Set rule without a rulemaking process is not clearly within our statutory authority. The statute requires that the cellulosic biofuel volumes in 2023 and future years be established through a rule and based on an assessment of the statutory factors. Were EPA to attempt to modify the cellulosic biofuel obligation outside a rulemaking process these changes could be overturned by a court, prompting additional rules to cure issues identified by a court and resulting in ongoing uncertainty. We further note that historically our projections of cellulosic biofuel production have been subject to a notice and comment process, and that there are potential drawbacks to adjusting the cellulosic biofuel volumes based on a projection without the benefit of public comment, whether through a rulemaking process or some other public process.

We request comment on the sufficiency of the existing carryover RIN provisions to stabilize demand for cellulosic biofuel and cellulosic RINs in the event of a surplus of cellulosic RINs. We also request comment on other mechanisms that could be adopted to further address a potential RIN surplus, including the mechanisms suggested by cellulosic biofuel producers discussed in the preceding paragraphs, and on any other ways that EPA could help provide the necessary support for continued development of the cellulosic biofuel industry while also being consistent with our statutory obligations.

[159] Letter from Anew, Energy Power Partners, Opal Fuels, DTE Vantage, and Iogen to US EPA. August 26, 2022.

B. Non-Cellulosic Advanced Biofuel

The volume targets established by Congress through 2022 anticipated significant growth in advanced biofuel beyond what is 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 indeed the applicable standards for 2022 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. This process included a consideration not only of production and import of non-cellulosic advanced biofuels, but also of the availability of qualifying feedstocks. Based on this analysis of supply-related factors, we estimated that some moderate growth after 2022 was achievable.

TABLE VI.B–1—NON-CELLULOSIC ADVANCED BIOFUEL CANDIDATE VOLUMES

Year	Volume (million RINs)
2023	5,100
2024	5,200
2025	5,300

We then analyzed these candidate volumes according to the other statutory factors.

In practice 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. Some of the statutory factors assessed by EPA suggest that the targets for non-cellulosic advanced biofuel established by Congress, or even higher volumes, are still appropriate. Notably, 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.[160]

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. We have therefore focused our attention on the impacts of these fuels in determining appropriate levels of non-cellulosic advanced biofuel for 2023–2025.[161] High domestic production capacity and availability of imports indicate that volumes of non-cellulosic advanced biofuel through 2025 may meet or even 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 these feedstocks have many existing uses that may require replacement with other suitable substitutes, there is also potential for ongoing growth in the production of some of these feedstocks. Higher implied volume requirements for non-cellulosic advanced biofuel may also have energy security benefits, increase domestic employment in the biofuels industry, and increase income for biofuel feedstock producers.

Some of the factors assessed would support lower volumes of non-cellulosic advanced biofuel. For instance, as described in DRIA 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 some adverse consequences. As described in DRIA Chapter 6.2, 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. We expect that the primary feedstock available to biodiesel and renewable diesel producers in significant quantities through 2025 will be soybean oil and other vegetable oils whose primary markets are for food. Increased demand for soybean oil could lead to diversion of feedstocks from food and other current uses in addition to further incentivizing increased soybean crushing and soybean production. Increased soybean production in the U.S. and abroad 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 shown in Table VI.B–1 would be reasonable and appropriate to require. As a result, in this action we are proposing increases of 100 million gallons per year from 2023–2025 of non-cellulosic advanced biofuel over the implied volume requirement of five billion gallons finalized for 2022. These increases reflect our consideration of the potential for significant GHG reductions that may result from their use, balanced with the relatively small projected increases in related feedstock production through 2025 and the potential negative impacts associated with diverting some feedstock from existing uses to biofuel production. As discussed in greater detail in Section VI.D, the relatively modest proposed increases in the non-cellulosic advanced biofuel implied volume requirement also recognize that some quantities of non-cellulosic advanced biofuel beyond what is required may be used to help satisfy the implied conventional renewable fuel volume requirement.

C. Biomass-Based Diesel

As described in the preceding section, we are proposing increases of 100 million gallons per year in the implied non-cellulosic advanced biofuel volume requirement from 2023 through 2025. In concert, we are also proposing to increase the BBD volume requirement by an energy-equivalent amount (65 million physical gallons) per year from 2023 through 2025. This approach would be 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.

As in recent years, we believe that excess volumes of BBD beyond the BBD volume requirements that we are proposing 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

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

[161] 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.

has driven the use of BBD in the market. Moreover, BBD can also be driven by the implied conventional renewable fuel volume requirement insofar as corn ethanol use as E15 and E85 is less economical as a means of compliance with the applicable standards than BBD. We believe these trends will continue through 2025.

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. We seek comment on the proposed increase to the BBD standard and whether other options should be considered.

D. Conventional Renewable Fuel

Although Congress had intended cellulosic biofuel to dominate the renewable fuel pool by 2022, instead, conventional renewable fuel has remained as the majority of renewable fuel supply since the beginning of the RFS program. The favorable economics of blending corn ethanol at 10 percent into gasoline caused it to quickly saturate the gasoline supply shortly after the RFS2 program began and it has remained in nearly every gallon of gasoline 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.[162] [163] Arguably, the market has come to expect that the applicable percentage standards will include 15 billion gallons of conventional renewable fuel, and has oriented its operations accordingly.

As discussed in Sections III.B.4 and III.B.5, based on supply-related factors we determined that 15 billion gallons of conventional renewable fuel remains a reasonable candidate volume for years after 2022. It was this volume that we analyzed according to the other statutory factors.

As discussed in Section III.B.5, constraints on ethanol consumption have made reaching 15 billion gallons with ethanol alone infeasible, and we expect these constraints to continue in at least the near term. 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 decrease over these three years. 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 be met with conventional renewable fuel or advanced biofuel, and with ethanol or non-ethanol biofuels.

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.

Several of the factors that we analyzed highlight the importance of ongoing support for 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 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,[164] 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.

As discussed in Section V, we are proposing a supplemental volume requirement of 250 million gallons for 2023, representing the second step of our response to the remand of the 2016 standards. This supplemental volume requirement could be met with any qualifying renewable fuel, including corn ethanol. It could also be met with carryover RINs rather than RINs representing new renewable fuel consumption. In establishing the 250-million-gallon supplemental standard for 2022, we indicated that we thought the market could generate additional RINs to meet the standard. We believe the same is true for 2023. In the alternative, obligated parties could choose to comply with carryover RINs.[165] As a result, the inclusion of a supplemental volume requirement of 250 million gallons in 2023 would have the net effect that the implied conventional renewable fuel volume

[162] 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 proposes to respond to this remand through the application of supplemental standard in 2023 that, combined with an identical supplemental standard in 2022, would rectify our inappropriate use of the general waiver authority for 2016 through which we had reduced implied volume requirement below 15 billion gallons.

[163] 87 FR 39600 (July 1, 2022).

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

[165] In past years we have noted a strong reluctance on the part of obligated parties to use carryover RINs for compliance with the applicable standards. They appear to prefer using RINs associated with new renewable fuels consumption when possible, preserving their carryover RIN banks for use in the event that future supply falls short of that needed to meet the applicable standards.

requirement is effectively 15.25 billion gallons rather than 15.00 billion gallons.

Since the market will likely have oriented itself to supplying 15.25 billion gallons of conventional renewable fuel in 2023 (or some combination of conventional renewable fuel and advanced biofuel), we considered whether it could do so in subsequent years as well. Although gasoline demand is projected to decrease between 2023 and 2025, that decrease is small: 0.1 percent from 2023 to 2024, and 0.3 percent from 2024 to 2025.[166] Given the increased use of E15 and E85 over this same timeframe, we project that total ethanol use will actually increase between 2023 and 2025 as discussed in Section III.A.5. We are thus proposing that the implied volume requirement for conventional renewable fuel in 2024 and 2025 be 15.25 billion gallons.

Nevertheless, we recognize that any increase in the implied volume requirement for conventional renewable fuel above 15 billion gallons could be seen as inconsistent with Congress's implied intention that all increases in renewable fuel after 2015 be in advanced biofuel, the vast majority of which was cellulosic biofuel. And as stated above, it is possible that the 250-million-gallon supplemental volume requirement for 2023 could be met entirely with carryover RINs, requiring the market to supply 250 million gallons of additional renewable fuel for the first time in 2024. If limitations in domestic supply result in increased imports to meet the need for 250 million gallons, we believe that those imports would most likely be in the form of renewable diesel produced from palm oil. While grandfathered under 40 CFR 80.1403 and thus qualifying, this form of renewable fuel would be unlikely to provide any meaningful GHG benefits and could contribute to deleterious environmental impacts in places where palm oil is produced, such as in Malaysia and Indonesia. We therefore request comment on whether the implied volume requirement for conventional renewable fuel should remain at 15.00 billion gallons in 2024 and 2025.

E. Summary of Proposed Volume Requirements

For the reasons described above, we are proposing the following volume requirements for the four component categories. Also shown is the supplemental volume requirement addressing the 2016 remand, discussed more fully in Section V.

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

[Billion RINs]

	2023	2024	2025
Cellulosic biofuel	0.72	1.42	2.13
Biomass-based diesel [a]	2.82	2.89	2.95
Non-cellulosic advanced biofuel	5.10	5.20	5.30
Conventional renewable fuel	15.00	15.25	15.25
Supplemental volume requirement	0.25	0	0

[a] BBD volumes are given in billion gallons.

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—PROPOSED VOLUME REQUIREMENTS FOR STATUTORY CATEGORIES

[Billion RINs]

	2023	2024	2025
Cellulosic biofuel	0.72	1.42	2.13
Biomass-based diesel [a]	2.82	2.89	2.95
Advanced biofuel	5.82	6.62	7.43
Total renewable fuel	20.82	21.87	22.68
Supplemental volume requirement	0.25	0	0

[a] BBD volumes are given in billion gallons.

We believe that these proposed volume requirements would preserve and continue the gains made through biofuels in previous years when the statute specified applicable volume targets. In particular, these proposed volume requirements would help ensure that the transportation sector would realize additional reductions in GHGs and that the U.S. would experience greater energy independence and energy security. The proposed volume requirements would 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 2023. Therefore, our standards for 2023 will be late and partially retroactive. Nonetheless, we believe that the proposed volume requirements for 2023 could be met despite this fact. With the issuance of this action, we are providing obligated parties with notice prior to 2023 of the likely volumes for that year. Thus, the market can have a reasonable expectation that the proposed volume requirements will be the basis for the final applicable percentage standards unless public comments that we receive in response to this proposal compel us

[166] As projected by EIA's Annual Energy Outlook 2022. We note that this outlook occurred prior to the sharp increase in world oil prices and thus gasoline prices as a result of the war in Ukraine. Future outlooks may thus have a lower gasoline demand forecast.

to modify them. Even in that case, meaningful changes to the proposed volume requirements would require a supplemental proposal, giving the market another opportunity to adjust expectations. While we anticipate that the 2023 standards will require increases in renewable fuel use over the 2022 standards, we also anticipate that such increases can be met by the market. We project that there will be sufficient RINs available for 2023 compliance. Obligated parties will also have at least nine months from the time of promulgation of this final rule before they are required to submit associated compliance reports.[167]

F. Request for Comment on Volume Requirements for 2026

Although we are proposing volume requirements and applicable percentage standards for three years, we are also requesting comment on finalizing the same for an additional year, 2026. If we were to do this, we would intend to extend to 2026 the same trends that we are proposing for 2023–2025 for BBD, non-cellulosic advanced biofuel, and conventional renewable fuel. As a result, non-cellulosic advanced biofuel would increase an additional 100 million RINs in 2026, BBD would continue to increase at a rate consistent with the growth in non-cellulosic advanced biofuel, and conventional renewable fuel would remain at 15.25 million RINs. Cellulosic biofuel volumes would continue to increase through projected growth in the use of renewable electricity as both the electric vehicle fleet expands and additional biogas to electricity generation capacity comes online as discussed in DRIA Chapter 6.1.4. Projecting these impacts for 2026 is considerably more uncertain than the projections for 2023–2025 given that growth in biogas electricity generating capacity is expected to be needed beyond the current supply and that growth is expected to be influenced by the availability of eRINs, for which we do not yet have a track record to evaluate.

If we were to finalize volume requirements and the associated percentage standards for 2026, we would intend to use the values shown below. We solicit comment on these volume requirements, including whether we should take final action to adopt them at the same time as we establish the requirements and standards for 2023–2025.

TABLE VI.F–1—POSSIBLE 2026 VOLUME REQUIREMENTS FOR COMPONENT CATEGORIES

Category	Volume (billion RINs)
Cellulosic biofuel	2.56
Biomass-based diesel [a]	3.02
Non-cellulosic advanced biofuel	5.40
Conventional renewable fuel	15.25

[a] BBD volumes are given in billion gallons,

TABLE VI.F–2—POSSIBLE 2026 VOLUME REQUIREMENTS FOR STATUTORY CATEGORIES

Category	Volume (billion RINs)
Cellulosic biofuel	2.56
Biomass-based diesel [a]	3.02
Advanced biofuel	7.96
Total renewable fuel	23.21

[a] BBD volumes are given in billion gallons.

G. Request for Comment on Alternative Volume Requirements

As described above, we are proposing volume requirements that we believe are both supported by the analyses that we are required to conduct and that would meet the policy goals of increasing the use of renewable fuels over time and reducing emissions of greenhouse gases. Nevertheless, we recognize that our provisional decisions to establish volume requirements for three years that include an effective conventional volume requirement of 15.25 billion gallons represent a significant policy choice for the program. We further recognize that stakeholders have suggested to EPA that we establish lower volume requirements than we are proposing in this action, particularly with respect to conventional renewable fuel. We are therefore requesting comment on various alternative approaches that we could take, both with respect to volumes as well as certain other policy parameters. We welcome general comments on our policy choices as well as specific comments on the particular topics identified below.

As discussed in Section III.A, we believe that proposing volume requirements for three years provides an appropriate balance between, on the one hand, our desire to strengthen market certainty by establishing applicable standards for as many years as is practical, and on the other hand our expectation that longer time periods increase uncertainty in the projected volumes. Greater uncertainty increases the likelihood that the applicable standards could turn out to be not reasonably achievable or to accomplish programmatic goals and might need to be waived or revisited at a later date. Moreover, while we have made projections regarding how the market might respond to the applicable standards, establishing volume requirements for three years in this rulemaking means that those projections will be based on data available today that might be inapplicable by 2024 or 2025. The annual standard-setting rulemaking process that came to define the RFS program in previous years permitted us to adjust the next year's applicable volume requirements more frequently according to how the market was responding to previous year volume requirements. As a result, we request comment on establishing volume requirements through this rulemaking for only one or two years rather than three years. Doing so would enable us to account for the evolution of the fuels market in something closer to real time, and more generally to assess newer data, potentially making the standards that we set more reasonably achievable or more aligned with programmatic goals. However, establishing standards for only one or two years would also make it more difficult to establish future standards by the statutory deadlines (October 31, 2022, for the 2024 standards, and October 31, 2023, for the 2025 standards).

Separately, and as discussed in Section III.C.3, the proposed inclusion of a supplemental volume requirement of 250 million gallons in 2023 to address the remand of the 2016 standards would effectively result in an implied conventional renewable fuel volume requirement of 15.25 billion gallons in that year.[168] [169] We believe that this implied volume requirement could be met without the need for obligated parties to use carryover RINs for compliance, and without the need for imports of palm-based renewable diesel. We also determined that once the market had oriented itself to supply 15.25 billion gallons in 2023, it could also do so for 2024 and 2025. Nevertheless, we recognize that uncertainty in volume projections for longer periods, as well as potentially

[167] Based on the deadline of June 14, 2023, for EPA to sign a rulemaking to finalize the 2023 volumes pursuant to the consent decree in *Growth Energy* v. *Regan, et al.,* No. 1:22–cv–01191 (D.D.C.), EPA expects the 2023 compliance deadline to be March 31, 2024. See 40 CFR 80.1451(f)(1)(A).

[168] The implied conventional volume requirement itself would be 15.00 billion gallons in 2023, but the inclusion of the 250 million gallon supplemental standard would effectively make it 15.25 billion gallons.

[169] See also the discussion of our obligations regarding the 2016 remand in Section V.

increasing demand for domestic soybean oil and other vegetable oils, could impel the market to turn to imports of palm-based renewable diesel to help fulfill an implied conventional renewable fuel volume requirement in 2024 and 2025 of 15.25 billion gallons. Therefore, we request comment on maintaining the implied conventional renewable fuel volume requirement at 15.00 billion gallons for these two years.

Finally, we acknowledge concerns among some stakeholders about the impacts of the volume requirements on the price of Renewable Identification Numbers (RINs). More specifically, the level of the implied conventional renewable fuel volume requirement has a largely binary impact on D6 RIN prices: If it is set below the E10 blendwall as was the case before 2013, D6 RIN prices are very low (perhaps a few ¢/RIN), whereas if it is set above the E10 blendwall, D6 RIN prices are considerably higher, rising to a level near that of advanced biofuel RINs.[170] [171] Our proposal includes an effective volume requirement for conventional renewable fuel of 15.25 billion gallons for 2023–2025 which is considerably higher than the E10 blendwall. As a result, we do not expect D6 RIN prices to be on the order of a few ¢/RIN.

While we believe that 15.25 billion gallons can be achieved in 2023–2025, we do not believe that it is possible with corn ethanol alone. Instead, we expect that significant volumes of BBD in excess of that needed to meet the applicable volume requirement for advanced biofuel would also be needed.[172] As shown in Table III.C.3–3, we project that about 14.5 billion gallons of the implied conventional renewable fuel volume requirement would be met with corn ethanol, with the remainder being met with BBD.[173] The same market outcome could be expected if the implied conventional volume requirement was set at 14.5 billion gallons and the advanced biofuel volume requirement was increased in concert, such that the total renewable fuel volume requirement remained unchanged. While this approach would guarantee that no amount of renewable fuel in excess of corn ethanol could be imported palm-based renewable diesel, thus maximizing the probability that the GHG benefits associated with our proposed standards occur, it would not be likely to have any impact on D6 RIN prices because 14.5 billion gallons is still above the E10 blendwall. In order to have a meaningful impact on D6 RIN prices, we would need to reduce the implied conventional renewable fuel volume requirement to below the E10 blendwall.

As discussed in Section III.C.3, our projection of the volume of corn ethanol that could be consumed in 2023–2025 incorporates the additional ethanol that could be consumed in the form of E15 and E85, and also accounts for some gasoline consumed as E0. In the absence of any E15 or E85, but under the assumption that the market would continue to offer some E0, the E10 blendwall would be as follows:

TABLE VI.G–1—PROJECTED E10 BLENDWALL [a] [b]

Year	E10 Blendwall (billion gallons)
2023	13,885
2024	13,865
2025	13,828

[a] Based on total gasoline energy demand from EIA's Annual Energy Outlook 2022, Table 2.

[b] Assumes that the average denatured ethanol content of E10 is 10.1 percent, and that the market continues to supply 2,128 million gallons of E0. See DRIA Chapter 6.5.2.

In order to ensure a meaningful impact on D6 RIN prices, the market would have to have confidence that the standard was in fact below the E10 blendwall. Thus, the implied conventional renewable fuel volume requirement would need to be somewhat lower than the levels shown in Table VI.G–1, possibly on the order of about 200 million gallons. The resulting reduction in the conventional renewable fuel volume (after accounting for other advanced ethanol) would then be added to the advanced biofuel volume, resulting in the volume targets shown in Table VI.G–2 rather than the volume requirements shown in Table I.A.1–1.

TABLE VI.G–2—PROPOSED VOLUME TARGETS

[Billion RINs]

	2023	2024	2025
Cellulosic biofuel	0.72	1.42	2.13
Biomass-based diesel [a]	2.82	2.89	2.95
Advanced biofuel	7.27	8.34	9.19
Renewable fuel	20.82	21.87	22.68
Supplemental standard	0.25	n/a	n/a

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

If we were to establish volume requirements according to the values in Table VI.G–2, we would expect that portion of the implied conventional renewable fuel volume requirement that would be met with ethanol in the form of E15 and E85 under our proposal to instead be met with additional BBD; by design, this alternative approach would essentially eliminate any incentive for E15 and E85. On the one hand, such a shift might be expected to increase the GHG benefits of the program since BBD is required under the statute to meet a GHG reduction threshold of 50 percent while conventional renewable fuel is required to meet a GHG reduction threshold of 20 percent. On the other hand, an increase in supply of BBD could place additional strain on the BBD feedstock supplies, resulting on some backfilling with imported palm oil, which could offset some or all of the GHG benefit one might otherwise expect.

We request comment on these alternative approaches to establishing standards in this proposed rulemaking, including the number of years for which we would establish standards, whether the implied conventional renewable fuel volume requirement should be 15.00 billion gallons rather than 15.25 billion gallons in 2024 and 2025, and whether the implied conventional renewable fuel

[170] The E10 blendwall represents the volume of ethanol that could be consumed if all gasoline was E10, and there was no E0, E15, or E85.

[171] Above the E10 blendwall, D6 RIN prices can also vary considerably due to a variety of market factors.

[172] See discussion in Section III.C.3.

[173] The 14.5 billion gallons of corn ethanol would include some used as E15 and/or E85.

volume requirement should be reduced by some other amount, such as below the E10 blendwall, while keeping the total renewable fuel volume requirement unchanged. While we have not conducted a detailed assessment of all of the impacts of these alternatives, we have estimated the impacts of these alternatives on retail fuel prices in DRIA Chapter 10.5.5.

VII. Proposed 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 is silent with regard to how applicable volume requirements should be implemented for years after 2022. 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, we considered the use of percentage standards as the implementation mechanism for volume requirements. We determined that this mechanism was effective and reasonable. We also determined that no straightforward and easily implementable alternative mechanisms existed. Therefore, we propose to continue 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). 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).[174] The RVOs are the number of RINs that the obligated party is responsible for procuring to demonstrate compliance with the RFS rule 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.[175] The volumes used to determine the proposed 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 PROPOSED APPLICABLE PERCENTAGE STANDARDS

[Billion RINs]

	2023	2024	2025
Cellulosic biofuel	0.72	1.42	2.13
Biomass-based diesel [a]	2.82	2.89	2.95
Advanced biofuel	5.82	6.62	7.43
Renewable fuel	20.82	21.87	22.68
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 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). As we are continuing to use the percentage standard mechanism to implement the volume requirements for years after 2022, we are not proposing any changes to those formulas. In addition to the required volumes of renewable fuel, the formulas also require estimates of the volumes of non-renewable gasoline and diesel fuel, for both highway and nonroad uses, which are projected to be used in the year in which the standards will apply. In previous annual standard-setting rules, the projected volumes of gasoline and diesel were provided by the Energy Information Administration (EIA) in a letter that was required under the statute to be sent to EPA by October 31 of each year.[176] However, this statutory requirement ends in 2021 and therefore does not apply to compliance years after 2022. Moreover, historically those letters received by EPA from EIA provided gasoline and diesel volume projections reflecting those in EIA's Short Term Energy Outlook (STEO).[177] While the STEO only provides volume projections for one future calendar year, this was sufficient for past annual standard-setting rulemakings since they never established applicable percentage standards for more than one future calendar year. This rulemaking, in contrast, proposes volume requirements and associated percentage standards for three future calendar years. Therefore, we could not use the STEO as a source for projections of gasoline and diesel for this action. Instead, we are proposing to use an alternative EIA publication for the purposes of calculating the percentage standards in this proposal, namely EIA's 2022 Annual Energy Outlook (AEO).

The projected gasoline and diesel volumes in AEO 2022 include projections of ethanol and biomass-based diesel used in transportation fuel. Since the percentage standards apply only to the non-renewable gasoline and diesel, the volumes of renewable fuel are subtracted out of the EIA projections of gasoline and diesel. The table below provides the precise projections from AEO 2022 that we have used to calculate the proposed percentage standards for 2023–2025.

[174] 40 CFR 80.1407.

[175] As discussed in Section V, we are proposing a supplemental standard for 2023 to address the remand of the 2016 standards under *ACE*. That supplemental standard would be 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 could be combined.

[176] CAA section 211(o)(3)(A)

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

TABLE VII.A–1—AEO2022 GASOLINE AND DIESEL VOLUMES FOR THE CALCULATION OF PERCENTAGE STANDARDS FOR 2023–2025

Fuel category	Table	Line
Gasoline	Table 2	Total Energy Consumption/Motor Gasoline.
Renewables blended into gasoline	Table 2	Energy Use & Related Statistics/Ethanol (denatured) Consumed in Motor Gasoline.
Diesel	Table 11	Product Supplied/by Fuel/Distillate fuel oil/of which: Diesel
Renewables blended into diesel	Table 11	Biofuels/Biodiesel + Biofuels/Other Biomass-derived Liquids.

In order to convert projections in energy units into volumes, we used the conversion factors provided in AEO 2022 Table 68.

B. Treatment of Small Refinery Volumes

Because we are proposing to continue the use percentage standards as the implementation mechanism through which the volume requirements would be effectuated, small refineries will continue to be required to produce proportionally smaller RFS volumes than larger obligated parties. And importantly, we do not anticipate that during the years covered by this proposal small refineries would be able to secure SREs to excuse compliance with these proportional RFS 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 volumes proposed 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. This is because in April and June 2022, EPA denied all pending SRE petitions for years spanning 2016 through 2020, finding that, consistent with *Renewable Fuel Association* v. *EPA,* SREs can only be granted if a small refinery demonstrates disproportionate economic hardship caused by compliance with the RFS program requirements and not other factors.[178] Consistent with our prior actions, we found that that none of the small refinery petitioners suffered disproportionate economic hardship caused by their compliance with the RFS because 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 fuel. Accordingly, we denied all SRE petitions.

Because the CAA interpretation and analysis presented in the April and June 2022 SRE Denials will apply equally to these future-year SRE petitions, we anticipate no SREs will be granted for these future years, including the 2023–2025 compliance years covered by this proposal. 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; therefore all small refineries will be required to comply with their proportional RFS obligations.[179] Even were EPA to grant a SRE in the future for 2023–2025, such an action would not meaningfully alter our projection of SREs used in calculating the percentage standards.

C. Proposed 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 proposed rule are shown in Table VII.C–1 for 2023, 2024, and 2025.

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

[Billion RINs]

Term	Description	2023	2023 Supplemental	2024	2025
RFV_{CB}	Required volume of cellulosic biofuel	0.72	0	1.42	2.13
RFV_{BBD}	Required volume of biomass-based diesel[a]	2.82	0	2.89	2.95
RFV_{AB}	Required volume of advanced biofuel	5.82	0	6.62	7.43
RFV_{RF}	Required volume of renewable fuel	20.82	0.25	21.87	22.68
G	Projected volume of gasoline	139.71	139.71	139.46	139.13
D	Projected volume of diesel	52.62	52.62	52.47	52.47
RG	Projected volume of renewables in gasoline	14.50	14.50	14.50	14.62
RD	Projected volume of renewables in diesel	3.22	3.22	3.22	3.22
GS	Projected volume of gasoline for opt-in areas	0	0	0	0
RGS	Projected volume of renewables in gasoline for opt-in areas	0	0	0	0
DS	Projected volume of diesel for opt-in areas	0	0	0	0
RDS	Projected volume of renewables in diesel for opt-in areas	0	0	0	0
GE	Projected volume of gasoline for exempt small refineries	0	0	0	0

[178] See generally,''April 2022 Denial of Petitions for RFS Small Refinery Exemptions,'' EPA–420–R–22–005, April 2022; ''June 2022 Denial of Petitions for RFS Small Refinery Exemptions,'' EPA–420–R–22–011, June 2022.

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

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

[Billion RINs]

Term	Description	2023	2023 Supplemental	2024	2025
DE	Projected volume of diesel for exempt small refineries	0	0	0	0

[a] The BBD volume used in the formula represents physical gallons. The formula contains a 1.57 multiplier to convert this physical volume to ethanol-equivalent volume, consistent with the proposed change to the BBD conversion factor discussed in Section IX.D.

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

TABLE VII.C–2—PROPOSED PERCENTAGE STANDARDS

	2023	2024	2025
Cellulosic biofuel	0.41%	0.82	1.23
Biomass-based diesel	2.54	2.60	2.67
Advanced biofuel	3.33	3.80	4.28
Renewable fuel	11.92	12.55	13.05
Supplemental standard	0.14	n/a	n/a

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

VIII. Regulatory Program for Renewable Electricity

Renewable fuels under the RFS program can be broadly categorized as liquid biofuels, such as ethanol or biodiesel, or non-liquid biofuels such as renewable compressed natural gas (renewable CNG) or renewable liquified natural gas (renewable LNG) used as transportation fuel. Non-liquid renewable fuels have played a part in the RFS since 2010, when EPA promulgated final regulations establishing the RFS2 program (2010 final rule).[180] In that final rule, EPA discussed the relevant differences between liquid and non-liquid renewable fuels and established regulatory provisions for non-liquid fuels that recognized those distinctions, including for renewable CNG/LNG and electricity derived from renewable biomass (renewable electricity) that is used as a transportation fuel.

EPA has registered multiple facilities and companies since 2010 that generate RINs under approved renewable CNG/LNG pathways, and today those entities produce hundreds of millions of ethanol-equivalent gallons of renewable CNG/LNG every year. CNG/LNG vehicles and engines, while not as widespread as other technologies used for transportation, have existed for decades and are often seen, for example, in company and municipal fleets. Today, renewable CNG/LNG comprises the vast majority of cellulosic biofuel generating RINs under the RFS.

The development of renewable electricity's role in the RFS program, however, has differed from that of renewable CNG/LNG. The 2010 RFS2 final rule determined that renewable electricity is, in certain circumstances, a qualifying renewable fuel and established regulatory provisions governing the generation of RINs representing renewable electricity in anticipation of a future action in which EPA would provide a RIN-generating pathway for electricity made from renewable biomass and used as transportation fuel. In 2014, EPA established such a RIN-generating pathway for electricity made from biogas.[181]

Despite the fact that renewable electricity has been part of the RFS program since 2010, EPA has not, to date, registered any party to generate RINs from renewable electricity. Since 2014, several stakeholders have submitted registration requests to generate RINs for renewable electricity. EPA reviewed these registration requests and met with a range of stakeholders; however, we ultimately determined that the structure of a program to generate RINs for electricity in the RFS program could present unique, unanticipated policy and implementation questions that needed to be resolved prior to registering any party, particularly in light of the competing policy preferences of stakeholders. Based on (1) our review of registration requests, (2) information gathered from stakeholders via both comments provided in response to EPA requests and ongoing discussions, and (3) an analysis of how to best incorporate renewable electricity into the RFS program, we concluded that EPA's existing regulations governing the generation of RINs for renewable electricity are insufficient to guarantee overall programmatic integrity, especially in light of the range of different and often competing approaches proposed by registrants. As a result, we determined it was necessary to establish a new regulatory program to govern the generation of RINs representing renewable electricity (''eRINs''). This proposed regulatory program for eRINs is intended to further the statutory goal to increase the use of renewable fuels over time, to do so in a manner that ensures that renewable electricity that generates RINs is produced from renewable biomass and is used as transportation fuel, and to incorporate qualifying renewable electricity used as transportation fuel into the RFS program in the same manner that liquid fuels have been since the inception of the RFS program.

EPA has gained significant experience since 2014 in implementing an RFS program that allows qualifying RIN generation for both liquid and non-liquid renewable fuels that can inform the design and implementation of a program for renewable electricity. In this notice, we are proposing a new set of regulations to govern the implementation and oversight of the

[180] 75 FR 14670, 14729 (March 26, 2010).

[181] 79 FR 42128 (July 18, 2014).

generation of eRINs under the existing RIN-generating pathways for renewable electricity. While EPA previously approved electricity as a valid renewable fuel under the statutory definition, the existing regulations are not sufficient to enable electricity to fully participate in the RFS program. This proposal is intended to remedy the deficiencies in the existing regulations and to allow for the generation of RINs for renewable electricity that is qualifying renewable fuel. We believe that the new regulations we are proposing in this action would serve the purposes of CAA section 211(o) to increase the use of renewable fuel in the transportation sector, would enable qualifying renewable electricity to participate in the RFS program, and would ensure that all renewable electricity that generates RINs is produced from biogas made from qualifying renewable biomass [182] and is used to replace or reduce the quantity of fossil fuel present in a transportation fuel, consistent with the statute.

The RFS program includes a range of biofuels that qualify as renewable fuel under the CAA. Consistent with the statutory volume targets requiring increasing volumes of renewable fuel to be used for transportation in the United States (see section 211(o)(2) generally), EPA has promulgated regulatory requirements for each participating renewable fuel that are designed to incentivize increased use of that fuel. EPA recognized in 2014 that renewable fuels such as CNG/LNG and electricity could support this statutory purpose, noting in the 2014 rulemaking that established RIN-generating frameworks for renewable CNG/LNG and electricity that the pathways and programs being added to the regulations ''have the potential to provide notable volumes of cellulosic biofuel.'' [183] We also explained that the changes being made ''will facilitate the introduction of new renewable fuels under the RFS program. By qualifying these new fuel pathways, this rule provides opportunities to increase the volume of advanced, low-GHG renewable fuels—such as cellulosic biofuels—under the RFS program.'' [184] As a result of the regulatory program that EPA designed and implemented for renewable CNG/LNG, volumes of this biofuel increased from 32 million ethanol-equivalent gallons in 2014 to 561 million ethanol-equivalent gallons in 2021.

Thus, this proposal to revise the RFS regulations governing eRIN generation is consistent with both the statutory goal of increasing volumes of renewable fuels and with the treatment of renewable fuels generally under the RFS program. As with other renewable fuels, we intend and expect the incentives created by the new regulations governing the generation of eRINs to result in increased volumes of renewable electricity being used for transportation in the United States. We also expect that the incentive to use qualifying renewable electricity in electric vehicles would, in turn, incentivize increased vehicle electrification that would continue to allow for increased generation of qualifying renewable electricity. These ancillary impacts are consistent with efforts elsewhere in the federal government to, for example, support the ongoing electrification of the vehicle fleet.[185] However, we emphasize that we are proposing this action in order to effectuate the determination we made in 2010 that renewable electricity can be a qualifying renewable fuel under the RFS program and consistent with the program's statutory mandate to increase the amount of qualifying renewable fuel used for transportation in the United States.

In this proposed action we are not reopening the 2010 decision to allow for the generation of RINs for renewable electricity if it is produced from renewable biomass and can be identified as actually having been used as transportation fuel.[186] Nor are we reopening the lifecycle analysis for the 2014 promulgation of RIN-generating pathways for renewable electricity in rows Q and T of Table 1 to 40 CFR 80.1426. We are also not proposing any new RIN-generating pathways in this action. Any comments on the 2010 or 2014 actions, or on potential new RIN-generating pathways for eRINs, will be considered beyond the scope of this rulemaking.

Our proposed approach, detailed below, would permit vehicle original equipment manufacturers (OEMs) to generate eRINs based on the light-duty electric vehicles [187] they sell by establishing contracts with parties that produce electricity from qualifying biogas (renewable electricity generators). Under this proposal, eRINs would represent the quantity of renewable electricity determined to be used by both new and previously sold (legacy) light-duty electric vehicles for transportation, provided that sufficient renewable electricity has been produced and contracted by the OEM.

We are proposing that qualifying renewable electricity (*i.e.,* renewable electricity generated under Row Q or T of Table 1 to 40 CFR 80.1426) produced and put on a commercial electrical grid serving the conterminous U.S. could be contracted for eRIN generation so long as the OEM demonstrates that the vehicles it produced have used a corresponding quantity of electricity. Under the proposed approach, EPA would establish requirements for biogas generators and electricity producers, but only an OEM would be allowed to generate the eRIN, though the value of the eRIN would be expected to be distributed after its generation amongst multiple parties. In this notice, we describe in detail our proposed approach and associated design elements and propose regulations that would implement the approach. We also describe several other alternative approaches to designing the eRIN program and ask for comment on those alternatives. The alternative approaches include allowing producers of renewable electricity to generate eRINs, allowing public access charging stations to generate eRINs, allowing independent third parties to generate eRINs, and a number of hybrid approaches that would allow multiple parties to generate eRINs. We also considered how other programs, like California's Low Carbon Fuel Standard, address similar policy goals and challenges.

This section is divided into multiple subsections. The first two subsections provide the context within which our

[182] For purposes of this preamble, we use the term ''qualifying biogas'' to refer to biogas made from renewable biomass under an EPA-approved pathway. An EPA-approved pathway is any pathway listed in Table 1 to 40 CFR 80.1426 or in a petition approved under 40 CFR 80.1416. In Table 1 to 40 CFR 80.1426, Rows Q and T contain the currently listed pathways for biogas used as a feedstock. Pathways that involve the use of biogas as a feedstock approved under 40 CFR 80.1416 are available on our website, ''Approved Pathways for Renewable Fuel,'' at *https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel.*

[183] 79 FR 42128 (July 18, 2014).

[184] Id.

[185] See, *e.g.,* Executive Order 14057 (Dec. 8, 2021), which sets a target of 100 percent acquisition of zero-emission vehicles for federal agencies by 2027, and Executive Order 14037 (August 5, 2021), which sets a goal that 50 percent of all new passenger cars and light-duty trucks sold in 2030 would be zero-emission vehicles, including battery electric, plug-in hybrid electric, or fuel cell electric vehicles.

[186] See 75 FR 14686 (March 26, 2010).

[187] For purposes of this preamble, by light-duty vehicle (sometimes referred to as light-duty cars and trucks), we mean collectively light-duty vehicles and light-duty trucks as defined in 40 CFR 86.1803–01. By electric vehicle or EV, also for purposes of this preamble, we mean collectively electric vehicles and plug-in hybrid electric vehicles as defined in 40 CFR 86.1803–01. A light-duty electric vehicle is a vehicle that is both a light-duty vehicle (*i.e.,* light-duty vehicle or light-duty truck) and an electric vehicle (*i.e.,* electric vehicle or plug-in electric hybrid vehicle).

proposed eRIN program was developed, including the historical treatment of electricity in the RFS program and the unique elements of renewable electricity as a qualifying transportation fuel. In subsequent subsections we introduce and discuss, among other things:

- Policy goals in developing the eRIN program
- Regulatory goals in developing the eRIN Program
- The proposed applicability of the eRIN program
- The proposed eRIN program structure
- Alternatives to the proposed structure
- Proposed changes to equivalence values
- Proposed compliance and enforcement provisions

We request comment on all aspects of our proposed eRIN program, including elements related to renewable natural gas (RNG) addressed separately in Section IX.I and our projections of future eRIN supply discussed in Section III.B.1.b.

A. Historical Treatment of Electricity in the RFS Program

1. Statutory Authority and Regulatory History

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 EPAct2005, 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.'' [188] 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.[189] This statutory definition of renewable biomass includes separated yard waste, separated food waste, animal waste material, and crop residue, any of which could be used to produce biogas through anaerobic digestion.[190] Additionally, the statutory definition of advanced biofuel codified at CAA section 211(o)(1)(B)(ii)(V) explicitly identifies biogas as a valid form of advanced biofuel.

It is important to note that, consistent with the statutory definition of renewable fuel provided by EISA, qualifying renewable electricity under the RFS program must be generated from a feedstock that qualifies as renewable biomass under Clean Air Act Section 211(o)(1)(I). Unlike some other renewable electricity programs, electricity generated from energy sources such as solar, wind, and hydropower does not qualify as renewable electricity or renewable fuel under the RFS program.

EPA is required to develop regulations to, *inter alia,* ''ensure that transportation fuel sold or introduced into commerce in the United States (except in non-conterminous States or territories), on an annual average basis, contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel [. . .].'' [191] Congress further required that EPA's regulations provide for a credit mechanism under which a person could generate credits and use or transfer them for the purpose of achieving the required annual volumes of renewable fuels. Although the credit system must provide ''for the generation of an appropriate amount of credits by any person that refines, blends, or imports gasoline that contains a quantity of renewable fuel that is greater than'' the statutory volume, as well as for the generation of credits for biodiesel and by small refineries,[192] the statute does not limit credit generation to these parties, nor does it specify the mechanics of credit generation, transfer, or disposition.

Finally, EISA required EPA to conduct a study and issue a report to Congress on the feasibility of issuing credits under the RFS program for renewable electricity used in electric vehicles.[193] In the 2010 rulemaking in which EPA promulgated regulations to implement the RFS2 program, EPA determined that electricity, as well as natural gas and propane, could meet the statutory definition of renewable fuel and thus be eligible to generate RINs if it was made from renewable biomass and if parties could ''identify the specific quantities of their product which are actually used as a transportation fuel.'' [194] In the same rulemaking, EPA established a qualifying RIN-generating pathway for biogas used as transportation fuel as an advanced biofuel when derived from landfills, sewage waste treatment plants, and manure digesters.[195] While EPA did not promulgate a specific pathway for renewable electricity at that time, it did establish provisions governing the treatment of renewable electricity as well as natural gas and propane (*i.e.,* CNG and LNG), provided that those fuels were derived from biogas and that specific quantities of the fuels used as transportation fuels could be measured.

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.[196] Inclusion of these new pathways in Table 1 was intended to allow for the generation of RINs for renewable electricity (along with renewable CNG and renewable LNG) that is used in transportation and is produced from a qualifying biogas (*i.e.,* biogas that is produced from renewable biomass). Pathway Q allowed for cellulosic biofuel RIN generation for renewable electricity 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 advanced biofuel RINs generation for renewable electricity from biogas from waste digesters, which encompasses non-cellulosic biogas. These two new pathways were structured so that biogas from approved sources would be the feedstock and renewable electricity would be the finished fuel for RIN generation purposes.

The Pathways II rule also established a set of regulatory provisions that detail the criteria necessary for renewable electricity to be demonstrated to be renewable fuel and thus eligible to generate RINs under two scenarios. First, for electricity that is only distributed via a closed, private, non-commercial system, the electricity must be produced from renewable biomass under an EPA-approved pathway and demonstrated to be sold and used as transportation fuel.[197] Under this scenario, only renewable electricity that was generated inside a closed transmission network (*e.g.,* an electricity generating unit co-located at a landfill)

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

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

[190] Biogas was explicitly included in EPAct2005 as a renewable fuel at CAA section 211(o)(1)(C)(i)(I)(bb) and therefore was included in the RFS1 program that applied from 2006–2009. In the 2010 rulemaking which established the RFS2 program based on changes to 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).

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

[192] CAA section 211(o)(5).

[193] Public Law 110–140, 206(b)–(c) (2007).

[194] 75 FR 14670, 14686 (March 26, 2010).

[195] 75 FR 14670 (March 26, 2010). The CAA includes ''biogas'' as one of the types of renewable fuels ''eligible for consideration as advanced biofuel.'' CAA section 211(o)(1)(B)(ii).

[196] 79 FR 42128 (July 18, 2014).

[197] 40 CFR 80.1426(f)(10)(i).

where the renewable electricity is directly supplied as transportation fuel to EVs could generate RINs.

The second scenario under which RINs could be generated for renewable electricity addresses when electricity is introduced into a commercial distribution system (*i.e.,* a transmission grid). In addition to the criteria noted above, potential RIN generators under this scenario must also demonstrate that the renewable electricity was loaded onto and withdrawn from a physically connected transmission grid, that the amount of electricity sold as transportation fuel is covered by the amount of renewable electricity placed onto the transmission grid, and that no other party relied on the renewable electricity for the creation of RINs.[198] These additional requirements for electricity transmitted via a transmission grid were designed to ensure that the amount of renewable electricity claimed to have been used as transportation fuel corresponds with the amount of renewable electricity placed onto the transmission grid and that such electricity is not double counted for RIN generation. Notably, however, the regulations do not specify how or where the quantity of electricity is measured, which party is the RIN generator, how a RIN generator demonstrates that the electricity was actually used as transportation fuel, nor how the RIN generator demonstrates that the electricity is not double counted.

2. Need for New Regulations

Due to the lack of specificity in the current regulations for how potential RIN generators would demonstrate that electricity was produced from renewable biomass and used as a transportation fuel, the registration requests that EPA has received vary considerably in their approaches. The main point of variation is the party that would generate the eRINs. Suggestions have included:

- Parties that use renewable electricity in a specified fleet of EVs (*e.g.,* fleet operators)
- Parties that dispense renewable electricity at public charging stations
- Parties that generate renewable electricity from qualifying biogas
- Parties that produce the qualifying biogas for renewable electricity generation
- Groups of interested EV owners that use renewable electricity (*e.g.,* groups representing individual light-duty EV owners)
- EV manufacturers whose vehicles use renewable electricity.

The existing regulations did not envision this broad range of differing approaches to eRIN generation. Registrants must be able to demonstrate in their requests that the quantity of eRINs to be generated could not be counted by another party[199] (*i.e.,* the regulations prohibit the double counting of RIN generation for the same quantity of renewable electricity). Thus, for a given quantity of renewable electricity, at most one party—whether it is the renewable electricity generator, the utility distributing the electricity, the EV owner, the charging station, or the vehicle manufacturer—can generate the corresponding eRINs. However, many of the current eRIN registration requests use different sources and types of information to verify the use of renewable electricity as transportation fuel and therefore conflict with one other. Given the wide variety of approaches in registration requests submitted to EPA, double counting would be almost certain to occur were we to register more than one of the current applicants. In other words, to prevent double counting, acceptance of any one of these eRIN generation registration requests under the existing regulations would necessarily preclude the acceptance of others and constrain the ability of the RFS program to grow renewable electricity volumes out into the future.

In light of this situation, we requested comment on the need for regulatory changes related to several foundational eRIN-related topics in the 2016 Renewable Enhancement and Growth Support (REGS) proposed rule.[200] We did not propose any amendments to the existing regulations governing eRIN generation at 40 CFR 80.1426(f)(10)(i) and (11)(i) at that time. Topics on which we requested comment include preventing double-counting, eRIN program structure, and the equivalence value[201] for renewable electricity. Below we provide a high-level summary of comments EPA received in response to the 2016 notice.

Preventing double counting of RINs is critical to the integrity of the RFS program. The credit program EPA established pursuant to Clean Air Act 211(o)(5) is the mechanism for ensuring that transportation fuel in the United States contains the required volumes of renewable fuel; if RINs do not correspond to the appropriate volume of renewable fuel, the credit mechanism breaks down. As noted above, because the existing eRIN regulations could potentially allow different parties using different information to generate RINs for the same volumes of renewable electricity, we determined that the existing regulations are not sufficient to prevent double counting and we sought comment on this issue (*i.e.,* on ways to prevent double counting) in the 2016 REGS proposal. However, in general, the public comments we received on the REGS proposal focused primarily on eRIN program structure and whether EPA should change the equivalence value for renewable electricity. The limited public comment on double-counting we did receive focused on the fact that EPA could avoid double-counting if EPA would specify, to the exclusion of other parties, a specific RIN generator and rely upon a single set of information for eRIN generation.

We received a significant number of comments regarding eRIN program structure. This level of response was not unexpected given the importance to the stakeholders regarding which entity in the supply chain would be regulatorily permitted to act as the RIN generator, and which entities would be able to receive revenue from the eRIN. Stakeholders from numerous parts of the renewable electricity lifecycle (biogas producers, renewable electricity generators, vehicle manufacturers, public access charging station operators, etc.) submitted comments which indicated they were the most reasonable entity to act as the RIN generator. Often these positions were predicated on a specific set of data that a particular stakeholder uniquely had access to and in their estimation was the most logical data on which to base eRIN generation. EPA received suggestions for many different program structures, and our review of these comments confirmed that many of the recommended structures and existing registration requests were mutually exclusive.

We evaluated the comments received in response to the REGS proposal, the registration requests that have been submitted, and the additional potential eRIN generation approaches that have been suggested to us. In light of the complexity associated with tracking valid eRIN generation and qualified use (*i.e.,* transportation use) under the RFS program, we have concluded that it is necessary and prudent to develop a modified and expanded set of comprehensive regulatory provisions to ensure that renewable electricity which qualifies under an approved RIN-generating pathways (*e.g.,* Row Q or T) is used as transportation fuel, and is not

[198] 40 CFR 80.1426(f)(11)(i).

[199] See 40 CFR 80.1426(f)(11)(F), which states that ''[n]o other party relied upon the renewable electricity for the creation of RINs.''

[200] 81 FR 80828 (November 16, 2016).

[201] See Section VIII.I for a discussion of our proposal to revise the equivalence value for renewable electricity.

double-counted.[202] We acknowledge that the proposed approach contained in this action is only one of many approaches that could be established, and that stakeholders have diverse opinions on program design. We look forward to further stakeholder input on the proposed approach contained herein, the multiple policy and technical questions associated with that approach, and alternative regulatory structures that could potentially accomplish the same goals.

We understand that some stakeholders who have submitted eRIN registration requests take the position that their requests could and should be accepted without any further action on the part of EPA to modify the applicable regulations. Regardless of whether any one registration request meets the regulatory requirements, under the existing regulations, EPA very likely cannot approve one request without denying all subsequent requests. Such an outcome would be contrary to the purpose of the RFS program and thus to broader EPA policy and implementation goals. While we acknowledge that it may be possible to develop a renewable electricity generation and use a business model that could enable registration under the existing regulations, it would require that all aspects—from biogas production to electrical generation and use in transportation—be carried out on-site by the same entity. Such a model would result in an overly narrow eRIN program that would limit the potential growth of renewable electricity. Although it would avoid double counting, it would also preclude the development of a more broadly applicable and equitable framework for an eRIN program that would be capable of incentivizing the full potential volume of renewable electricity used as transportation fuel.

We believe that the policy and regulatory design questions confronting the Agency are sufficiently broad and complex that issuing new regulations to govern an eRIN program is necessary. We further believe that doing so provides maximum transparency into our policy development process and offers stakeholders a chance to provide comment on and improve our proposed approach.

B. The eRIN Generation and Disposition Chain

In this subsection, we introduce and briefly discuss a number of key concepts and terms that are used throughout our discussion of eRINs and our proposed approach for governing their generation. As mentioned above, in designing this new eRIN program EPA is able to draw upon its experience implementing an RFS program that currently includes both liquid and non-liquid fuels. Even with this experience, however, there are aspects to the generation and use of renewable electricity in the program that are unique, and which raise implementation and design questions that we have not addressed before in other parts of the program. This subsection is intended to provide descriptions of foundational concepts that underlie and/or are used throughout this notice, including all the various actors that participate in the eRIN value chain. A starting point for this discussion relates to how biogas is converted into electricity.

1. Biogas and Renewable Natural Gas

Under the current RFS program, we broadly define 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.'' [203] Biogas typically contains a significant amount of impurities and inert gases (*e.g.,* carbon dioxide) and must undergo pre-treatment before it can be used to generate electricity and especially before it can be used as CNG/LNG in vehicles. In order for the natural gas commercial pipelines to accept injections of biogas, the biogas must first be upgraded to meet pipeline specifications prior to injection. This pipeline quality biogas is called renewable natural gas (RNG) [204] and is fungible with fossil-based natural gas. Electricity can be produced by combusting treated biogas or RNG; the only difference is that the former is not pipeline quality while the latter is.

2. Renewable CNG and LNG

For biogas to be used as renewable CNG/LNG to fuel a vehicle (*i.e.,* not used to generate electricity), 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 current regulations,[205] we require that parties demonstrate through contracts and affidavits that a specific volume of RNG is used as transportation fuel within the U.S., and for no other purpose. RNG that parties can demonstrate via contract is used for transportation is often called contracted RNG. Although not required by EPA's regulations, typically under the RFS program, in order for parties to enter into a contract to help the RIN generator demonstrate that a volume of RNG was produced from renewable biomass and is used as transportation fuel, that party contracts for a portion of the value of the RIN generated for the volume.

We call the chain of parties that are involved in ensuring that biogas is produced from renewable biomass and used as transportation fuel the generation/disposition chain. For renewable CNG/LNG, this chain includes:

- The biogas producer (*i.e.,* the landfill or digester that produces the biogas)
- The party that upgrades the biogas into RNG
- The parties that distribute and store the RNG (*e.g.,* pipelines)
- 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

[202] As discussed in Section IX.I, we also believe that a new set of regulatory provisions is needed for the production, transfer, and use of biogas to accommodate a program that allows for multiple uses of biogas—as renewable CNG/LNG, to generate renewable electricity, and as a biointermediate to produce renewable fuels other than renewable CNG/LNG or renewable electricity. The proposed allowance for the use of biogas, in the form of RNG, for multiple purposes under the RFS program would create an increased risk for the multiple counting of the biogas for RIN generation resulting in invalid and fraudulent RINs. The proposed biogas regulatory reform provisions, discussed in Section IX.I, are designed to work in tandem with the eRINs proposal to put in place a cohesive biogas program that would minimize the potential for the multiple counting of biogas for different uses. The proposed biogas regulatory reform provisions are intended to provide the specificity needed to streamline the onboarding of potentially hundreds of EGUs producing renewable electricity from biogas into the program in a very short amount of time. Were we not to finalize the proposed biogas regulatory reform provisions discussed in Section IX.I, then we would need to put in place additional/different requirements for eRINs in order to avoid multiple counting of eRINs.

[203] See 40 CFR 80.1401. 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. Also note, as discussed in Section VIII.K, we are proposing to modify the definition of biogas consistent with the proposed eRIN program and proposed biogas regulatory reform described in Section IX.I.

[204] For purposes of this preamble, by renewable natural gas or RNG, we mean a product derived from biogas that contains at least 90 percent biomethane content and meets the commercial distribution pipeline specification for the pipeline that the biogas is injected into. Biomethane is the methane component of biogas and RNG that is derived from renewable biomass. Under the current regulations, parties generate RINs for the energy, in BTUs, from the biomethane content (exclusive of impurities, inert gases often found with biomethane in biogas) that is demonstrated to be used as transportation fuel.

[205] 40 CFR 80.1426(f)(10)(ii), (f)(11)(ii).

produced from renewable biomass and used as renewable CNG/LNG.

If biogas is directly supplied to an end user via a private pipeline, the CNG/LNG generation/disposition 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. Under EPA's current regulations, any party in a biogas generation/disposition chain can generate the RINs, but as part of this action we are proposing to modify the biogas-to-renewable CNG/LNG regulations to specify a particular RIN generator, as discussed in detail in Section IX.I.

3. Converting Biogas/RNG to Electricity

In a majority of situations where biogas is combusted to produce electricity, an electricity generation unit (EGU) is collocated with the source of the biogas. For example, a landfill operation may have an onsite electricity generation unit like a reciprocating internal combustion engine or a gas turbine.[206] In these situations, only a relatively minimal amount of gas cleanup is needed prior to combustion. In some cases, though, non-collocated electricity generators buy contracted RNG. In both cases—onsite generation from biogas, or offsite generation from RNG—the generation/disposition chain for the electricity includes all the parties in the renewable CNG/LNG chain for the production and distribution of the biogas or RNG. As discussed in more detail later in this section, however, the chain lengthens significantly once the biogas or RNG is converted to electricity.

4. Tracking Renewable Electricity to Transportation Use in the United States

For most fuels under the RFS program, it is unnecessary to track the fuel from the point of its production to the point of end-use in order to demonstrate that the renewable fuel was actually used as transportation fuel. For example, once ethanol is denatured, it is reasonably presumed that it will be used as transportation fuel as it has no other practical uses.[207] Similarly, once biodiesel meets highway fuel specifications, it is presumed that it will be used as transportation fuel.

This is not the case, however, with RNG injected into a natural gas commercial pipeline system, where it is mixed with fossil natural gas. In that case, we are unable to assume that the main use of the RNG will be for transportation because only a small percentage of natural gas used in the United States is used for transportation.[208] When RNG moves through a pipeline system for distribution, the RNG is mixed with a much larger proportion of fossil natural gas using the same system. The two natural gases—one derived from renewable sources, the other from fossil sources—are fungible at that point.

Consequently, by the time the natural gas is used to fuel a vehicle, there is no meaningful way to identify which molecules of methane were originally sourced from biogas and which came from fossil sources. As discussed above, and in light of this dynamic, when EPA introduced RNG as a transportation fuel in the RFS program in the Pathways II rule, we set up a system whereby the demonstration that RNG was used as transportation fuel relied on accounting protocols, recordkeeping requirements, and requirements for contracts and affidavits attesting that a specific volume of RNG was used as transportation fuel, and for no other purpose.[209]

We face a similar situation with renewable electricity. Like natural gas, electricity's main use is for purposes other than transportation. Like RNG, the distribution of renewable electricity relies on and is fungibly distributed through the same distribution system (*i.e.,* the commercial electrical transmission grid) as for non-renewable electricity. The renewable electricity, once produced, is physically impossible to distinguish from non-renewable electricity. Whether produced from coal, wind, solar, hydro, natural gas, or biogas, and whether produced in California, New York, Canada, or Mexico, once electricity is on the commercial electrical transmission grid, it is only identifiable as electricity. The electricity that shows up in the vehicle's battery is an indistinct commodity. This means that, for any eRIN program that involves use of the commercial transmission grid, the tracking and verification that a given quantity of renewable electricity made from renewable biomass was in fact used as transportation fuel can only be done through accounting and records management. As with the generation of RINs for RNG, since the relevant records and the data on which those records are based exist at different locations and are managed by different parties, any eRIN program thus will also need to be based on the contractual transfer of information between parties.

There are multiple steps, and multiple actors, involved in the process chain from the point at which biogas is produced to the point where electricity is used to charge an EV. The actors, whom we will be discussing in various parts of this notice, include:

- Biogas producers (*e.g.,* landfills and agricultural digesters)
- Parties that clean up and compress biogas to pipeline-quality renewable natural gas (RNG)
- Biogas and RNG distributors (*e.g.,* natural gas pipelines)
- Renewable electricity generators
- Electricity transmission and distribution owners
- EV charging station owners
- Electric vehicle (EV) owners
- Vehicle manufacturers (original equipment manufacturers or OEMs)

Throughout the discussion in this notice, we refer to this process chain—from renewable electricity generation through use as a transportation fuel—along with all of the actors in that chain, as the ''eRIN generation/disposition chain.''

As is discussed throughout this proposal, in order to establish an eRIN program that is both consistent with the statutory requirements and implementable, information is needed to demonstrate that: (1) renewable electricity is being generated from qualifying biogas, and (2) that a commensurate amount of electricity is stored in the vehicle battery and thus actually used as transportation fuel. However, at points in between generation and use, all that is being transported is fungible electricity that is neither identifiable as renewable nor uniquely used for transportation. Consequently, the critical information needed for eRIN generation purposes is from parties on the front end where the electricity is produced and on the back end where it is consumed. Because the information is often not proprietary (*e.g.,* a vehicle owner, vehicle OEM and charge station will all have data on a vehicle's charge event, and almost all parties could have records on the quantity of electricity used for transportation), there is arguably no one single point in the eRIN generation/

[206] For more basic information on landfill gas energy projects, for example, see *https://www.epa.gov/lmop/basic-information-about-landfill-gas.*

[207] The regulations at 40 CFR 80.1401 states that in order for ethanol to meet the definition of renewable fuel, the ethanol must be denatured under the Department of Treasury's denaturant requirements at 27 CFR parts 19 through 21.

[208] EIA estimates that in 2020 only about 3 percent of natural gas was used for transportation, see *https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php.*

[209] See 40 CFR 80.1426(f)(11)(ii).

disposition chain, nor one single type of entity within that chain, that is clearly more appropriate to designate as the eRIN generator than any other from a technical perspective.

While from a technical perspective there may not be one party ideally suited to act as the eRIN generator, from a legal, program implementation, and policy perspective there are reasons to propose to designate one party in the chain as eligible to generate eRINs in the first instance (acknowledging that the RIN value could subsequently be shared among different parties). From a legal perspective, we must ensure that our choice of the designated eRIN generator is consistent with any applicable statutory requirements. From a policy perspective, we must ensure that our choice of the designated eRIN generator supports the program's ability to address key market constraints to the increased use of renewable electricity in transportation: renewable electricity production, EV fleet growth, and/or EV charging infrastructure. From a program implementation perspective, the nature of the eRIN generation/disposition chain also means there are different ways that EPA could structure the program to ensure that statutory requirements—that qualifying renewable electricity is being used for transportation—are met. Although each of the parties described in the chain play some role in facilitating the production, distribution, and use of renewable electricity produced from qualifying biogas and used as transportation fuel, some of them might be considered more critical to ensuring that the statutory requirements are met. We sought to include elements in our proposed program that we believe could both maximally encourage the generation of eRINs and ensure that the eRINs are valid. Ultimately, we concluded that the key factors/parties on which to focus for the proposal for purposes of program implementation are biogas production, renewable electricity generation, and EV fleet growth (through OEMs).

C. Policy Goals in Developing the eRIN Program

Renewable electricity used for transportation has been included in the RFS program since 2010; EPA's current task is to develop a revised set of regulations governing RIN generation for this renewable fuel. EPA's foremost policy goal in developing the proposed eRIN program is to support the RFS program's mandate to increase the use of renewable fuels, in particular cellulosic biofuels, over time, consistent with the statute's focus on growth in this category for years after 2015. Moreover, an eRIN program can also support Congress' goals of reducing GHGs and increasing energy security,[210] both of which can be affected by the design of that program. We anticipate that increasing renewable fuel volumes, in the form of allowing the generation of RINs for renewable electricity for use in transportation, will also have the ancillary effect of incentivizing increased electrification of the vehicle fleet. Where possible and consistent with our statutory mandate, we have considered these and other ancillary effects in formulating the eRIN program we are proposing in this action. We also believe it is critical to take into account the views expressed by stakeholders as well as our experience with biogas-derived renewable CNG/LNG under the RFS. Each of these goals is discussed below, and the discussion of the proposed program that we believe fulfills these goals is described in Sections VIII.E and F.

1. 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. 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. However, as also discussed in Section III.B.1, the opportunity for continued growth of RNG is expected to be constrained in the future due to the consumption capacity of the in-use fleet of CNG/LNG vehicles. As the use of RNG saturates the existing in-use fleet, the use of biogas as a feedstock for renewable fuel production will be constrained by the much slower growth in CNG/LNG fleet sales. At the same time, based on the number of existing landfills[211] and wastewater treatment facilities and the potential for significant expansion of anaerobic digesters,[212] there exists significant potential to increase the productive use of biogas to produce renewable fuel under the RFS program. By tapping into the greater market for that biogas that is and can be converted to renewable electricity, the impending constraints on the use of biogas as a feedstock for renewable fuel production can be mitigated. Specifically, by coupling the existing capacity for electricity generation from qualifying biogas with the expansion of EVs in the fleet that is already underway, the RFS program can increase renewable fuel use in transportation in keeping with the overarching goal of the program.

The use of renewable electricity from qualifying biogas as transportation fuel is also consistent with the statute's focus on growth in cellulosic biofuel over other advanced biofuels and conventional renewable fuel after 2015.[213] The existing RIN-generating pathways in rows Q and T of Table 1 to 40 CFR 80.1426 provide for the generation of D-code 3 (cellulosic) and D-code 5 (advanced) RINs, respectively. The determination that biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; and biogas from cellulosic components of biomass processed in other waste digesters is predominantly cellulosic was made in the 2014 Pathways II Rule.[214] In that rule, EPA further concluded that:

- Biogas-based renewable electricity achieved at least a 60 percent reduction in greenhouse gases relative to gasoline; and
- The majority of the biogas was likely to come from cellulosic material in a landfill or digesters that processed predominantly cellulosic materials.[215]

[210] 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).

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

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

[213] 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.

[214] 79 FR 42128 (July 18, 2014).

[215] The pathway in Row Q of Table 1 to 80.1426 allows for the generation of D3 RINs from renewable CNG/LNG produced from biogas from

However, as described in Section VIII.A, because we have not registered parties to generate eRINs under the existing regulations, biogas use has instead been limited to the CNG/LNG vehicle market under the RFS program. Moreover, based on conversations with stakeholders, we believe that other factors have also limited the ability of potential biogas production facilities from participating in the RFS program: the costs of biogas cleanup to the quality needed for injection into common carrier pipelines and use in CNG/LNG vehicles can be prohibitive, and many existing landfills and digesters are located a significant distance from the natural gas commercial pipeline system and cannot cost effectively connect. Enabling biogas to be used to generate renewable electricity and eRINs under the RFS program would open up not only a lower cost option for many biogas production facilities, but also enable an even lower GHG-emitting means of using available biogas resources for transportation.[216] Thus, we anticipate that one important consequence of this proposal would be to enable a substantially increased number of biogas production facilities to participate in the RFS program, thus expanding the opportunity for biogas to be used as a feedstock to produce a lower GHG-emitting renewable fuel.

The renewable electricity generators are an essential component of the production and use of renewable electricity as transportation fuel. Throughout the development of this proposal, we have heard from many stakeholders involved in the production of renewable electricity that have spoken about the financial difficulty of building new renewable electricity projects and keeping existing projects operational in order to increase electricity production. Given that sufficient renewable electricity generation is necessary in order to increase available volumes of renewable fuel, and in particular cellulosic biofuels, a primary consideration for this proposal was creating a mechanism through which renewable electricity generators would be provided an incentive to participate in the RFS program and increase renewable electricity production. We believe that the proposed program described in Section VIII.F would, through the eRIN revenue sharing agreements we anticipate would be created, significantly increase the participation in the program of renewable electricity generators, and thus the potential for growth in the production and use of renewable fuel in the form of renewable electricity used for transportation.

2. Incentivizing Growth in Renewable Fuel

Congress designed the RFS program to create incentives for and reduce barriers to the increased production and use of renewable fuel in the United States. For liquid biofuels, the primary constraints have generally been around renewable fuel production and the higher costs of renewable fuels relative to petroleum-based fuels; the existing vehicle fleet was typically capable of consuming the types and quantities of renewable fuels in the blends offered and has therefore not generally been a constraint. As a result, EPA's regulatory framework targeted the incentive, *i.e.,* the RIN value, at the renewable fuel producers. As explained above, existing constraints on certain parts of the renewable electricity generation/disposition chain have, to date, limited its potential use as transportation fuel in the United States. Thus, consistent with our approach to renewable fuels generally under the RFS program, in designing this proposed eRINs program one of our goals has been to target the eRIN incentive to where it is most likely to alleviate existing constraints on the increased use of renewable electricity as transportation fuel.

However, unlike liquid biofuels, electricity is not predominantly used as transportation fuel and renewable electricity cannot be renewable fuel unless and until it is demonstrated to actually have been used for transportation (liquid fuels can generally be assumed to be used for transportation once they enter the distribution system). This means that in order to address existing constraints on renewable electricity that qualifies as renewable fuel, we need to consider and incentivize both renewable electricity generation and transportation end use.

First, in order to increase renewable electricity used as renewable fuel it is necessary to ensure that adequate renewable electricity generation from qualifying biogas exists and will continue to exist into the future. Enabling the generation of eRINs under the RFS program has the potential to provide an incentive for the renewable electricity generation, which in turn directly supports the goal of increasing renewable fuel use over time. That is, incentivizing growth in renewable electricity is both a natural outcome of including electricity in the program and necessary to serve the statutory purpose of the RFS program. The renewable electricity market has many interrelated components, including the biogas production (*e.g.,* landfills and agricultural digesters), biogas and natural gas pipelines, the renewable electricity generating units, the electricity transmission and distribution grid, EV charge stations, EV manufacturing, and EV ownership and use. The design of the eRIN program has the ability to direct the incentives to the market components that can have the greatest impact on growing the use of renewable electricity for transportation purposes. We have heard from stakeholders representing almost every segment of this market. In general, each party we have heard from that is connected in some way to the renewable electricity market believes it is important that they either be able to generate the eRIN themselves or at least in some way derive some revenue from the eRIN to support investments in their component of the renewable electricity market.

The current RIN-generating pathways for renewable electricity are based on biogas production, which has been driven by factors other than the RFS program for many years that are likely to continue into the future. These factors include the proliferation of landfills and wastewater treatment facilities needed to support an expanding population, and various types of waste digesters whose biogas can be used to comply with the California LCFS program or to provide a new source of onsite energy. Enabling value from the eRIN to flow to support investment for growth in biogas and to expand the conversion of that biogas to renewable electricity (either onsite or offsite) is another component of increasing the use of renewable electricity and thus of renewable fuel under the RFS program.

A second significant constraint on increasing renewable electricity used as renewable fuel is the composition of the existing vehicle fleet. Just as with E15 and E85 compatible vehicles for ethanol and natural gas vehicles for RNG, without growth in the vehicle fleet that can consume renewable electricity, growth in the use of such electricity as renewable fuel will be constrained. In designing an eRINs program, it is thus

landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; and biogas from the cellulosic components of biomass processed in other waste digesters. For purposes of this preamble, a predominantly cellulosic material is a feedstock that has an adjusted cellulosic content of at least 75 percent.

[216] Converting the biogas to electricity at the same location where the biogas is produced tends to be the lowest GHG and lowest cost means of using it for transportation since it avoids the additional expense and energy consumption associated with cleaning up the gas, transporting it in a pipeline, and compressing/liquifying it prior to fueling a vehicle.

also important to consider whether and how it can support increased electrification of the transportation sector.

An eRINs program can help ensure that the increased use of renewable fuel is not limited by the size of the EV fleet. Growth in renewable electricity used as renewable fuel will depend in part on the economic attractiveness of EVs relative to their internal combustion engine counterparts. An eRIN program that is designed to meet the statutory objective of increasing renewable fuel use should thus allow for revenue from eRINs to incentivize activities that can increase electrification of the fleet, which could include lowering the cost of EVs and/or increasing the availably of public access charging infrastructure. From this perspective, enabling value from the eRIN to also flow toward EV manufacturers, EV charging stations, or even EV consumers would also be appropriate.

Regardless of the party that generates the eRINs, we believe an eRIN program should be designed so that all parties with regulatory responsibilities under an eRIN program would benefit under the proposed program (*i.e.,* would receive some portion of the value of eRINs). This is because, as explained above, qualifying renewable electricity as a transportation fuel depends on all parties in the regulatory framework having a financial incentive to participate. We expect that the market would adjust to apportion the value of eRINs among regulated parties in such a way as to ensure that they are all incentivized to increase production of qualifying renewable fuel.[217] Furthermore, regardless of the parties that are included in the regulatory framework for eRINs and therefore might benefit directly through some portion of the eRIN value, we believe that all parties in the value chain would benefit from the proposed eRIN program as it encourages renewable fuel growth.

Different eRIN program design structures can affect which aspect of the renewable electricity transportation value chain is most directly supported through the eRIN value. The proposed eRIN program structure outlined in Section VIII.F is intended to support the increased use of renewable fuel though targeted incentives for reducing the cost of EVs and the generation of renewable electricity from qualifying biogas. However, we acknowledge that other eRIN program structures are possible and, in Section VIII.H, discuss alternative eRIN program structures, including structures that are more focused on facilitating greater access to public access charging infrastructure, which may increase the use of renewable electricity as transportation fuel as well. Increasing the use of renewable electricity as transportation fuel is a multi-aspect challenge that is unlikely to be achieved through any singularly targeted policy. We are aware that both EV cost and access to public access charging infrastructure are important aspects of the challenge to increase use of renewable electricity as transportation fuel. That said, these are only two such aspects of a broader challenge, and that the need to target policy support to address them, may shift over time.

3. Taking Into Account Stakeholder Views and Needs

In our efforts to develop a functional eRIN program, we have identified numerous issues that are often complex and intertwined. These issues are evidenced by the disparate approaches presented in the registration requests we have received to date for eRIN generation, and in other feedback we have received from stakeholders in response to the 2016 REGS proposal and subsequent annual standard-setting rulemakings. There is clear and strong interest on the part of many parties in not only having a functional eRIN program as soon as possible, but also in ensuring that the program provides incentives to parties at particular stages in the eRIN generation/disposition chain. For these and other reasons, it is important for us to understand the views of all parties that are or could be regulated under the eRIN program. We encourage all parties to provide comments on all aspects of our proposed eRIN program.

D. Regulatory Goals in Developing the eRIN Program

In the course of developing the proposed eRIN program, we have evaluated and balanced as many factors as possible in order to construct a program that would ensure that the statutory requirements are met and that all eRINs generated are valid. This section describes the importance of ensuring that renewable electricity which can be used to comply with the applicable standards under the RFS program is generated from qualifying renewable biomass and is used as transportation fuel. Relatedly, we also considered how the regulatory program could be constructed to ensure that eRINs are not double counted and cannot be generated fraudulently. Finally, we discuss the regulatory goal of minimizing complexity while ensuring the integrity of eRINs. To these ends, we have drawn from experience with existing programs such as the current regulations governing biogas-based CNG/LNG and California's Low Carbon Fuel Standard (LCFS) program.

Details of our proposed eRIN program structure which we believe meet these goals are presented in Section VIII.F. A discussion of alternative program structures that we considered is then provided in Section VIII.H.

1. Ensuring That Renewable Electricity Is Produced From Renewable Biomass

Section 211(o)(1)(J) of the Clean Air Act requires that renewable fuels that qualify under the RFS program be produced from renewable biomass and used as transportation fuel, or, under certain circumstances, as heating oil or jet fuel.[218] Under the existing EPA-approved pathways, only biogas can be used to generate qualifying electricity, and that biogas must be produced from renewable biomass as defined in 40 CFR 80.1401. Rows Q and T of Table 1 to 40 CFR 80.1426 provide additional criteria regarding the biogas production processes that have been approved for RIN generation. Under Row Q, renewable electricity may be eligible to generate cellulosic (D-code 3) RINs if it is produced from biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, or separated MSW digesters; or if it is produced from biogas from the cellulosic components of biomass process in other waste digesters. In each of these cases, EPA has determined that the feedstocks in the landfill or digester that are generating biogas are predominantly cellulosic.[219] Under Row T, renewable electricity may be eligible to generate advanced biofuel (D-code 5) RINs if it is produced from biogas from waste digesters.[220]

As mentioned earlier, we are not proposing to reopen the determination that renewable electricity made from renewable biomass and used as transportation fuel qualifies as renewable fuel, nor the renewable electricity pathways in Rows Q and T, and we are not proposing any new RIN-generating pathways in this action. However, we are proposing a new set of implementation requirements including

[217] See further discussion in Section VIII.F.

[218] While the Clean Air Act and EPA regulations provide for renewable fuels used as a transportation fuel, heating oil, or jet fuel, renewable electricity is only available for use as a renewable fuel as transportation fuel due to technological, implementation and/or regulatory barriers. Therefore, for purposes of this preamble, we refer to transportation fuel as the only qualifying use of renewable electricity.

[219] 79 FR 42128 (July 18, 2014).

[220] Ibid.

registration, recordkeeping, and reporting requirements for biogas producers and renewable electricity generators that would be used to demonstrate that electricity that generates eRINs is produced from renewable biomass. These new requirements would more robustly ensure that biogas producers can demonstrate that their biogas is produced from renewable biomass and that they can contract with electricity generators for the purchase of such biogas to produce renewable electricity. The demonstration that renewable electricity is generated from biogas that is, in turn, produced from qualifying renewable biomass is the same regardless of the many eRIN program structures considered for this proposal. That is, the information collection and other requirements pertaining to the demonstration that electricity is produced from renewable biomass are largely independent of the other eRIN program elements that govern which party(ies) produces, collects, and uses that information in order to generate eRINs. Our proposed registration, recordkeeping, and reporting requirements are discussed in Section VIII.L.

2. Ensuring That Renewable Electricity Is Used as Transportation Fuel

In addition to being produced from renewable biomass, Clean Air Act section 211(o)(1)(J) requires that qualifying renewable electricity be used for transportation fuel. For every renewable fuel in the RFS program, we have imposed regulatory requirements to help ensure that the renewable fuel was used as transportation fuel as required by the Clean Air Act. Because each renewable fuel has a different production, distribution, and use chain, we tailor our regulatory requirements to the specific fuel. For example, for ethanol, we require that the ethanol be denatured in accordance with TTB requirements prior to the generation of RINs. We imposed this requirement because until the ethanol has been denatured, the ethanol could be used for non-qualifying (*i.e.,* non-transportation) use. After the ethanol has been denatured, the denatured ethanol is virtually guaranteed to be used as transportation fuel. Similarly, for biodiesel and renewable diesel, we require that such fuels must meet specified quality standards needed for the fuels to be used in diesel engines. After biodiesel and renewable diesel have been demonstrated to meet fuel quality specifications, we can be reasonably assured that those fuels will be used as transportation fuel. In cases where a biofuel has many purposes, making it relatively difficult to show that a fuel will be used as transportation fuel and nothing else, we impose additional regulatory requirements prior to RIN generation.[221] For example, in the case of natural gas where the majority is used for purposes other than transportation, we require that documentation be provided that demonstrates that the renewable CNG/LNG produced from biogas was used as transportation fuel and for no other purpose.

Similar to natural gas, the vast majority of electricity is currently used for non-transportation purposes. This fact was discussed in the 2010 RFS2 rulemaking where we highlighted the need for regulations to ensure that RIN-generating renewable electricity is actually used for transportation.[222] Therefore, in order to ensure compliance with the statutory definition of renewable fuel, a regulatory framework is needed to ensure that eRINs are generated only for the amount of renewable electricity used as transportation fuel.

a. Approaches for Quantifying Renewable Electricity Consumption in Transportation

Quantification under an eRIN system must take place both for renewable electricity production by EGUs and renewable electricity consumption by EVs. The ability to quantify how much electricity is used in an EV, and to quantify and verify how much of that can be ''claimed'' to be renewable electricity generated from qualifying biogas, is the foundation for determining how many eRINs may be generated, and for ensuring the program is structurally sound. Quantifying how much renewable electricity produced from qualifying biogas is a relatively straightforward matter, as it is metered when it is put on a commercial electrical grid serving the conterminous U.S. Quantifying the use of that electricity as transportation fuel, on the other hand, presents a more complex challenge. Based on a review of approaches used in other programs, like California's LCFS, and on approaches suggested to us by stakeholders, EPA considered two general approaches for how we could assess the amount of renewable electricity consumed in the EV fleet: a ''bottom-up'' and a ''top-down'' approach as described below. We acknowledge that both approaches are potentially implementable. The choice of which type of approach to use has implications for other program considerations discussed throughout this section, including implementation complexity, compliance burden, data privacy, and prevention of double counting and fraud.

Broadly speaking, a bottom-up approach would rely on using granular levels of data for EV charging events collected at vehicle charge stations and/or through vehicle telematics. California's LCFS program, discussed in Section VIII.H.5, uses a bottom-up approach to determining vehicle consumption data. In developing our proposed approach, we investigated several different bottom-up data sources and approaches to determining how much electricity is used and in which vehicles. Examples of sources EPA could potentially rely on to gather consumption data in such an approach include:

- Data from charging stations showing the amount of electricity each vehicle used to charge
- Data from onboard vehicle telematics, which records the vehicle battery's state of charge
- Dedicated meters added to Electric Vehicle Servicing Equipment (EVSE)
- Data loggers added to EVs
- Statistical methods

By recording, reporting, tracking, and verifying this data one can have reasonable assurance in the accuracy of both the individual eRIN generation events and the overall eRIN volumes when aggregated. However, the many potential sources of error and the sheer quantity of millions and eventually billions of individual vehicle charge events present a considerable challenge to verifying the authenticity and accuracy of the data which would be needed to ensure measured quantities actually represented real and/or not double-counted quantities of renewable electricity used in transportation. The level of effort associated with collecting, reporting and verifying all of this information on a continuous basis to support RIN generation at the national level would be considerable and affect a number of other programmatic design considerations. For example, regulated parties and EPA would have to develop mechanisms to store and report the millions of charging events in a consistent and implementable way. After such a mechanism was developed, procedures by regulated parties, third-party auditors, and EPA would have to be developed to ensure that such data representing charging events were appropriately utilized in the generation of RINs. Because of the sheer volume of

[221] See 40 CFR 80.1426(f)(17).

[222] See, *e.g.,* 75 FR 14686, 14729 (March 26, 2010).

charging events, errors and duplicative charging events would likely result in the almost continuous correction of electricity consumption data used for RIN generation in a ''bottom-up'' approach. These changes would necessitate specified procedures for dealing with any invalid eRINs generated on the erroneous data by the regulated party and by EPA. While addressing the volume of data and resulting errors presents a significant challenge, we acknowledge that the program could be structured in ways to minimize burden (*e.g.,* through targeted audits of the data, automated data quality control mechanisms designed into information collection systems, or the use of statistical methods to estimate and evaluate electricity consumption).

By contrast, and as further discussed in Section VIII.F, a top-down approach would use higher-level, aggregate data on EV fleet electricity use to generate consumption measurements. Such an approach would use existing data and information to generate overall market average values that could be used for eRIN generation. It would rely on the law of averages to ensure the overall accuracy of the result and would minimize errors associated with individual measurements.

For example, a top-down approach, rather than requiring granular detail on individual charge events, could determine consumption based on an equation that includes an OEM's EV fleet population and the average electricity consumption of those vehicles. Such an approach would be reliant upon an accurate characterization of the population of vehicles and the average electricity consumption of those vehicles in order to appropriately quantify the electricity consumed each year. A key factor, and a potential source of uncertainty for this approach, would be ensuring the data used to calculate the average annual energy consumption of EVs are in fact representative of what happens in the fleet. From a statistical standpoint, the central limit theorem dictates that the standard error of the population mean is far less than the standard error of any individual sample, suggesting that a population approach is more appropriate. Therefore, our use of the population-wide, annual average energy consumption of EVs would minimize uncertainty. Utilizing the entire electrified vehicle population, rather than a sample, also allows us to differentiate between the different types of EVs in use, something that would be much more challenging if we were to use information on individual charging events, which may not have precise data about the different EV types. Pairing the population data for vehicle type with vehicle use data (average annual energy consumption for BEV and PHEVs) would allow the program to appropriately credit average annual electricity consumption for each vehicle in the fleet. Within the PHEV category, it can also be used to differentiate between the all-electric range of the vehicle and the average annual electricity consumed.[223] Such a top-down approach (*i.e.,* based on average, aggregate electricity consumption) could provide a robust basis for quantifying the amount of electricity that is used in electric vehicles at the scale relevant to a national eRIN program. While we acknowledge that the approach may not be as precise for individual EV circumstances, it might be more accurate for electricity consumption of the national EV fleet and thus more appropriately capture renewable fuel use and further the statutory goal to increase the use of such fuel over time.

A top-down approach would also lend itself well to addressing a number of other important program considerations discussed throughout this section, including complexity, compliance burden, data privacy, and prevention of double counting and fraud. For example, a top-down approach would provide a means for demonstrating the use of electricity as transportation fuel without requiring any data that could potentially be used to identify individuals or their behaviors.

b. Data Privacy

The RFS program and its requirements generally apply to companies and the facilities those companies own/operate, with individual consumers quite removed from the RIN generation process as they simply fill up their tanks with renewable fuels (neat or blended) at their convenience. That is, for liquid biofuels, the determination that a fuel is used for transportation takes place upstream of the actual customer. While biogas used as CNG/LNG does require that the demonstration of transportation use occur at the fueling station, because this fuel is almost exclusively used by private or public fleet vehicles, the privacy of individual vehicle owners and users has never been a significant concern.

Electricity is fundamentally different than other renewable fuels that participate in the RFS program because individual consumers, in particular those charging their EVs at their homes, may be the parties that are best able to ultimately demonstrate that electricity is used for transportation, as opposed to some other purpose. When we evaluated many of the RIN generation structures proposed by stakeholders (*e.g.,* public access charging stations, LCFS, and vehicle telematics), it is the data associated with the unique charging behavior of individual vehicle owners for their vehicles such as charge location, time, and quantity that ultimately can be used to demonstrate the quantity of electricity used for transportation.

In the case of charge stations, it may be possible for the station owner to submit aggregated charging data that span charging events across locations and a specific period of time. However, even in this case, individual records with personal identifiable information would need to be kept and potentially audited for oversight and compliance purposes. In other situations, every unique charging event (including personal identifiable information, parameters of the charging event, and perhaps location) would need to be submitted so that the disaggregation of charge events could be performed. In the case of our proposed program, the information regarding vehicle use would be handled by the OEMs rather than EPA and would not be used directly for RIN generation. The process of how this data is intended to be utilized in the RIN generation process is outlined in greater detail in a technical memo to this proposal.[224]

We appreciate the fact that many individuals have concerns about information on their location and behaviors being submitted to, and retained by, a government agency. We have also heard from stakeholders about the challenges and limitations associated with the use of Personal Identifying Information (PII) in other programs given the existing and expanding constraints placed on the use of PII in state laws, including those in LCFS states such as California and Washington. They expressed concern that reliance on PII might unnecessarily constrain the generation of eRINs and thus the volume of renewable electricity that qualifies under the program. In an effort to respect these concerns, we believe that the approach we take to ensuring that renewable electricity is used as transportation fuel should avoid, to the extent possible, the

[223] We discuss the differentiation between BEVs and PHEVs further in RIA Chapters 1 and 2.

[224] Such data privacy concerns are not relevant for the top-down approach, as discussed further in the technical memorandum, ''Examples of RIN generation under the proposed RFS eRIN provisions,'' available in the docket for this action.

collection and use of potentially sensitive, private information such as vehicle charging data that identifies a person's location at any particular point in time and how they may have been using their vehicle. Up to this point, we have been able to design the RFS program in a manner that avoids the collection and use of potentially sensitive, private information, and we believe it is important to continue to do so to the extent practicable.

3. Preventing Double Counting and Fraud

In order for the RFS program to function, the RIN market must have integrity, *i.e.,* 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 been valid, a not insignificant quantity of invalid RINs have been generated.[225] The significant value of the RINs, particularly cellulosic RINs, provides incentives for fraudulent generation, and complicated renewable fuel production and distribution systems provide an opportunity for parties who are so inclined. Fraudulent RINs can be generated by parties fabricating reports or records to make RINs generated for non-existent fuels appear valid. 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. 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.

As we noted in the REGS proposal, the potential for double counting of eRINs is a significant concern due to the potential for double counting to undermine the credit system that EPA uses to implement the statutory volume requirements under CAA section 211(o). We noted that even though the existing regulations prohibit such double counting,[226] we had concerns that those regulations would not enable EPA to detect or protect against the double counting of eRINs because multiple types of data can be used to demonstrate the use of electricity as transportation fuel and some of these data overlap across datasets and are not proprietary to one party. For example, under the existing regulations, if an EV owner charged their vehicle at a public charging station, it is possible that the vehicle owner, charging station owner, and vehicle manufacturer would all have information documenting the amount of renewable electricity used in this single charging event and could all potentially use that data to generate eRINs.

Because of the similarities between renewable electricity used in EVs and RNG used in CNG/LNG vehicles, both of which are not predominately used as transportation fuel, double-counting concerns are also similar for both. As we have considered ways in which we can prevent double counting for renewable electricity, we considered how we might also strengthen the regulations to prevent double counting for RNG. As with the existing eRINs regulations, under the existing regulatory structure for biogas used to produce renewable CNG/LNG, parties generating RINs must demonstrate that no other party relied on that same volume of biogas, renewable CNG, or renewable LNG to generate RINs.[227] As stated previously, to date we have only approved registrations for the use of biogas used in CNG/LNG vehicles, not for the use of biogas to generate renewable electricity. However, we have concerns that, once we begin approving registration requests for renewable electricity, the opportunities for the double counting of biogas could increase dramatically. For example, a party may 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 renewable electricity generated from the same volume of RNG. We are proposing revisions to the regulatory requirements for RNG to prevent such double counting, which are presented in Section IX.I.

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 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 infraction. A material quantity of invalid RINs would create adverse market effects, as well. 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 electricity. Any viable eRIN program design must eliminate, to the extent possible, the ability of parties to generate invalid RINs, whether for double-counted renewable electricity or for double-counted biogas that is used to generate renewable electricity. Doing so could include, for instance, limiting the number of parties involved in the generation of a specific quantity of eRINs, holding all directly regulated parties in the eRIN generation/disposition chain liable for transmitting or using invalid RINs, and/or leveraging third-party oversight mechanisms (*i.e.,* third-party engineering reviews, RFS QAP, and annual attest engagements) to help identify, verify, and correct potential issues related to invalid RIN generation.

4. Program Complexity and Implementation Burden

In general, the more complex a regulatory program, the more resource-intensive it is for EPA to develop, implement, and oversee that program, and likewise the more difficult and resource-intensive it is for regulated parties to understand and successfully comply with it. Additionally, the more complex the program, the later its effective date must be in order to permit sufficient time for registration requests to be reviewed and accepted, and for regulated parties to establish the necessary compliance mechanisms. Furthermore, the more complicated and resource-intensive a new program, the greater the disproportionate effect on smaller entities, which often lack the resources and expertise to quickly understand and meet the new program's requirements. Finally, the more complex the program design, the more value is devoted to resources required to administer the program throughout the generation/disposition chain. These administrative costs have the potential to erode the program's key objectives. Therefore, one of our goals in developing the applicable regulations for the eRIN program was to minimize implementation burden by limiting the complexity of the program to the extent it is practicable to do so.

In the case of eRINs, we anticipate the participation of potentially hundreds of biogas-to-electricity projects using a variety of feedstocks and electricity generation technologies. These hundreds of parties would, in turn, contractually associate with hundreds of other parties as necessary to connect

[225] 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.*

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

[227] See 40 CFR 80.1426(f)(11)(ii)(H).

renewable biomass to biogas production, biogas to electricity generation, electricity to transportation use, and transportation use to eRIN generation. Given these facts, the complexity of the eRIN program could prove prohibitive to implement. A viable program design will depend, among other things, on which parties would be required to register with EPA and the data, information, and mechanisms parties use to demonstrate compliance with the regulatory requirements. The greater the number of registrants, the more complex and time consuming it will be to register parties to generate eRINs. Furthermore, the greater the amount of data and information that must be reported, reviewed, and verified, the greater the resource needs and time needed to design and implement the compliance oversight systems. Our goal in designing the eRIN program is to do so using a regulatory structure that is as straightforward as possible and that attempts to minimize undue complexity.

One aspect of program design we have investigated relates to the tracking of contractual information. When we implemented the requirements for RNG under the current regulations, we did so by requiring that contractual relationships between each and every party in the distribution system be provided and tracked to enable verification of RIN validity. However, we believe that we can design the eRIN program to largely avoid a similar level of complexity. In particular, while we have requirements in place for biogas under the current regulations to track such contractual relationships, we believe that they could be largely unnecessary in an eRIN program moving forward.[228] We also investigated ways to minimize program complexity by reducing the need for regulated parties to obtain and submit large amounts of data to the EPA that track billions of charging events. Section VIII.M presents our conclusions regarding these aspects of the eRIN program.

In addition, we have implemented the current regulatory provisions for biogas to renewable CNG/LNG for over eight years and have gleaned important lessons from this experience. As described in more detail in Section IX.I, the current provisions for biogas-derived renewable CNG/LNG contain a flexible, but resource-intensive set of regulatory provisions that we believe needs to be amended to allow for the use of biogas to produce renewable electricity. The two primary issues from our experience implementing the biogas to renewable CNG/LNG regulatory provisions that we believe should be addressed in an effective eRIN program are minimizing program complexity and avoiding double-counting.

One key determinant of program complexity concerns whether regulations permit more than one category of parties to be the RIN generator, or whether they designate only one category as eligible to generate RINs. To help inform this decision with respect to eRINs, EPA reviewed our experience implementing our CNG/LNG program in the RFS, where our current regulations allow any party in the biogas CNG/LNG generation/disposition chain to generate the RINs. We have concluded that while this approach does provide flexibility, it has also resulted in a complex program that arguably is overly burdensome for both EPA and industry. Under the current regulations, 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 was used as transportation fuel in the form of renewable CNG/LNG. These demonstrations occur both during registration in the form of voluminous registration requests, which can sometimes number over a thousand pages of contracts, and on an ongoing basis to support RIN generation in the form of contracts and affidavits from each party in the CNG/LNG generation/disposition chain to show that the biogas or RNG was used as transportation fuel. Because we anticipate that there are hundreds of existing biogas-to-electricity projects ready to participate in the proposed eRIN on the effective date of the rule, we believe that the existing program for biogas to CNG/LNG is likely not the appropriate model on which to base an eRIN program that will have many times more participating parties and facilities.

Renewable electricity also qualifies as transportation fuel under California LCFS program. We engaged in a number of conversations with California Air Resources Board (CARB) staff who developed and implemented the LCFS program, along with several companies which currently participate in it. These conversations gave us a better appreciation for how the LCFS program functions. While the LCFS program is governed by different legal requirements and other constraints than the RFS program and therefore cannot be used as a direct model for an eRIN program under CAA section 211(o), we were able to glean some valuable information from LCFS and CARB's experience implementing it that has factored into our proposed eRINs approach. Further discussion of the LCFS program as a model for eRINs under the RFS program is provided in Sections VIII.H.1 and VIII.H.5.a.i.

E. Proposed Applicability of the eRIN Program

In the sections that follow, we discuss the structure of our proposed eRIN program in two parts. This section presents our proposal for the program's applicability in terms of the renewable electricity for which RIN can be generated, the specific types of electric vehicles/engines which we propose would be covered, the geographic scope, and the timing for registrations and eRIN generation. Subsequently, Section VIII.F describes our proposed approach to eRIN generation, including designation of the eRIN generator and details regarding how eRIN generation would be quantified.

1. Approved RIN-Generating Pathways for Renewable Electricity

As discussed in Section VIII.A.1, EPA promulgated pathways for the generation of cellulosic (Row Q of Table 1 to 40 CFR 80.1426) and advanced (Row T) RINs for renewable electricity produced from biogas in the 2014 Pathways II rulemaking.[229] This proposal is limited to revising the regulatory structure for implementation of these existing pathways, which we are not revisiting or reopening here. While a number of stakeholders have requested that EPA promulgate additional pathways for production of renewable electricity from feedstocks other than biogas from renewable biomass, we are not doing so in this rulemaking.[230] Thus, at this time, only renewable electricity produced from biogas under one of the approved pathways in Rows Q and T of Table 1 to 40 CFR 80.1426 would be eligible to generate eRINs under our proposed program.[231] We anticipate promulgating

[228] In fact, as discussed in more detail in Section IX.I, we are proposing to reform the current biogas regulations in part to reduce the burden associated with implementation and oversight.

[229] 79 FR 42128, July 18, 2014.

[230] We reiterate that the promulgation of additional pathways is a separate action from promulgation of regulations to implement the existing pathways. Any comments on this proposal requesting that EPA promulgate additional pathways for the generation of eRINs, beyond those already contained in Table 1 to 40 CFR 80.1426, are outside the scope of this rulemaking.

[231] We note that if we were to finalize the proposed eRINs program, eRINs could also be generated under a facility-specific pathway for biogas to electricity approved under 40 CFR 80.1416. We have not approved any pathways for

additional eRIN pathways in the future and intend to revise the regulations to accommodate them as needed.

2. Covered Vehicles and Engines

As stated earlier, in order to qualify as renewable fuel under the Clean Air Act, renewable electricity generated from qualifying renewable biomass must be used for transportation. As part of developing a proposed program structure, we need to determine what qualifies as use for transportation and what data and information are then needed to demonstrate it. As explained below, while for some types of electric vehicles or engines we believe sufficient data are available to demonstrate that the electricity used is renewable fuel and quantify such use, we do not believe that is the case for all types of electric vehicles or engines at this time. Therefore, we are proposing a program under which only renewable electricity used in light-duty electric vehicles would be eligible to generate eRINs.

a. Light-Duty Electric Vehicles

Electrification of light-duty vehicles is relatively far along in its development compared to other applications within the transportation sector. The significant degree of light-duty electrification that has already occurred means that the data and information needed to link renewable electricity to transportation use are readily available. This information includes data related to real-world operation of light-duty electric vehicles that can be used to determine the amount of electricity used for transportation, including average vehicle use patterns and the efficiency of vehicle charging and vehicle operation. We discuss the particular vehicle information required for our proposed structure in Section VIII.F.5.a. Additionally, experience with electrification of light-duty vehicles to date has provided an understanding of which parties play what roles in the electrification of the vehicle fleet, including who holds what data and who is in a position to best ensure that double counting of eRINs does not occur.

As discussed further below, other end-uses within the transportation sector are at a considerably more nascent stage in their electrification and thus have considerably less data and information available. Although the Clean Air Act's definition of renewable fuel does not differentiate between renewable fuel used by one vehicle or engine type versus another, at this time we do not have sufficient information about electricity use in vehicles and engines other than light-duty EVs to determine the amount of renewable electricity that is used and to ensure that double counting of eRINs will not occur. Therefore, we are proposing in this action to limit eRIN generation to light-duty EVs. However, we intend to adopt a ''learning by doing'' approach for eRINs and anticipate that opportunities for expansion into other applications within the transportation sector may materialize as the program matures and sufficient information becomes available.

b. Treatment of Legacy Fleet

We are proposing to allow for the generation of eRINs from renewable electricity used in both new light-duty electric vehicles and light-duty electric vehicles that are part of the existing fleet (*i.e.,* legacy electric vehicles). So long as sufficient data and information exist for EPA to ensure that eRINs are generated only for renewable electricity that qualifies as renewable fuel, whether that renewable fuel is used in legacy or new electric vehicles is not relevant under the RFS program. This treatment is consistent with the treatment of other renewable fuels used in vehicles and engines under the RFS program. For example, the RFS program does not provide any more or less credit for ethanol blended into gasoline if the gasoline-ethanol blend is used in a model year (MY) 1970 light-duty vehicle or a MY 2022 light-duty vehicle; each gallon of ethanol can have a RIN generated for it regardless of the vehicle the ethanol will ultimately be used in. Therefore, consistent with other renewable fuels under the RFS program, we are proposing to allow the generation of eRINs for the use of renewable electricity in all light-duty EVs inclusive of the legacy fleet. We seek comment on this proposal.

As explained below, our proposal to permit eRINs to be generated for both new and legacy light-duty electric vehicles is viable because it does not rely on information collected from individual vehicles. For further detail, see Section VIII.F for a discussion of our proposed approach and Section VIII.H for a discussion of alternative approaches that we considered.

c. BEVs and PHEVs

The term ''electric vehicle'' covers a wide range of types of electric vehicles (*e.g.,* mild hybrids, hybrids, plug-in hybrids, and battery electric vehicles). However, there are two main types of electric vehicles that are potentially eligible to generate eRINs because they derive power from the commercial electrical grid serving the conterminous U.S. and therefore have the potential to use renewable electricity for transportation purposes.[232] The first, and most straightforward, type is full battery electric vehicles (BEVs).[233] Full BEVs only have an electrified drivetrain and rely entirely on electricity stored in their battery for all motive power. From a RIN accounting perspective, BEVs are relatively simple as it must be the case that all miles traveled by BEVs, *i.e.,* all transportation use, is reliant upon electricity.

The second type of vehicle that is potentially eligible to generate eRINs is plug-in hybrid electric vehicles (PHEVs). While PHEVs utilize electricity in their onboard battery, they also have an internal combustion engine in addition to the battery from which they can source motive power. Because of this duality, our proposed structure must include a mechanism for parsing the fraction of vehicle miles traveled (VMT) powered by electricity (often referred to as eVMT) from the fraction of VMT sourced from the internal combustion engine. A description of the proposed method used to accomplish this parse, along with the data collected to establish the procedure, are discussed in DRIA Chapter 6.1.4.

d. Applications Outside the Scope of the Proposed eRIN Program

As explained above, the eRIN program we are proposing in this action would cover only light-duty electric vehicles. We recognize, however, that other applications within the transportation sector, namely medium-duty and heavy-duty vehicles and nonroad equipment, can be electrified. In fact, just as with the light-duty market over the past decade, there are rapid advancements being made in electrification of these sectors, in particular in the highway medium-duty and heavy-duty vehicle sectors, where virtually every manufacturer has announced plans to commercialize electric vehicles and where early product offerings are now available. While we do not believe that it would be appropriate to include them in the eRIN program at this time, we intend to continue monitoring the electrification of heavy-duty vehicles and nonroad equipment and may consider including them in the future.

biogas to electricity under 40 CFR 80.1416 at the time of this proposal.

[232] There are other categories of hybrid electric vehicles, but generate their electricity onboard the vehicle and do not plug into the electric grid.

[233] The regulations at 40 CFR 86.1803–01 define this type of EV, and we are proposing to use the same definition.

i. Medium- and Heavy-Duty Vehicles

In contrast to light-duty vehicles and trucks, we do not believe we have sufficient information and data on electrified medium- and heavy-duty vehicle production and use to allow for eRIN generation associated with such vehicles at this time. The electrified medium- and heavy-duty markets are relatively nascent and there are relatively few vehicles currently being operated or offered for sale in the marketplace when compared to the light-duty vehicle sector.[234] This results in a general lack of data and information which would be needed to develop the regulatory program in terms of both ensuring the appropriateness of programmatic responsibilities and supporting the eRIN generation calculations required to quantify potential RIN generation. At the same time, the heavy-duty industry is at the beginning stages of expected rapid growth in zero emission vehicle technology, including battery electric vehicles, which we expect will help address this general lack of data in the coming years, as discussed further below.

We considered whether the proposed structure for light-duty electric vehicles and trucks could simply be extended to the medium- and heavy-duty markets. However, we concluded that until the market further develops it would not be possible to ensure the same regulatory requirements we are proposing for light-duty EVs would be appropriate for the future market of medium- and heavy-duty EVs. In the light-duty sector, the OEM builds the vehicle and powertrain and then introduces the entire vehicle to commerce. This is the pattern that the light-duty sector appears to be following as it transitions from internal combustion engines to EVs as well. Although this vertical integration occasionally exists in the heavy-duty markets, it is not typical at present. In the current heavy-duty vehicle market, it is often not clear who is the original equipment manufacturer (OEM). The engine, chassis, and trailers which together comprise a vehicle are often made by different manufacturers. The situation for the medium-duty market is often somewhere between that of light-duty and heavy-duty. How the medium- and heavy-duty EV markets develop is yet to be determined.

In addition, given the current low production volume of medium- and heavy-duty EVs, the manufacturers have little sales volume over which to spread the compliance and implementation burden associated with generating eRINs. These manufacturers are initially unlikely to be able to cost-effectively comply with or choose to devote the necessary resources to the proposed regulatory requirements to generate eRINs, *e.g.,* through the hiring of RIN market specialists and other resources to fulfill the obligations affiliated with generation and transacting of RINs.

Furthermore, because there are relatively few medium- and heavy-duty EVs and so little operational data from them it is not yet clear how such EVs will be used. Since the fueling, range, and cost-per-mile characteristics of medium- and heavy-duty EVs differ from light-duty vehicles, it is likely that medium- and heavy-duty EVs will be operated differently than their light-duty counterparts. Furthermore, given their different use cases, it is also likely that vehicle charging will be considerably different. Thus, there simply is not reliable information at this time for the medium- and heavy-duty sectors on factors such as vehicle miles traveled on electricity, charging efficiency, or specific energy consumption on which to base eRIN calculations and programmatic design decisions.

These are not sufficient reasons to propose to exclude medium- and heavy-duty vehicles from the eRIN program indefinitely, but we believe that they are relevant considerations to exclude them at this time. We recognize that the medium- and heavy-duty vehicle industry is at the early stages of a major transition to EV technologies, and over the next several years we will see a large growth in the range of EV product offerings and sales volumes. As this market grows, we will reassess the potential inclusion of medium- and heavy-duty electric vehicles once the eRIN program is established and more in-use data for medium- and heavy-duty electricity vehicles becomes available. For example, as a result of financial incentives put in place by the Bipartisan Infrastructure Law of 2021, a large number of electric school buses are expected to be introduced into the fleet in just the next few years. In addition, the Inflation Reduction Act of 2022 contains many significant incentives for zero emission heavy-duty vehicles (including infrastructure, R&D, manufacturing and purchase incentives), and we expect the industry and market to respond rapidly to take advantage of those incentives. Consequently, we anticipate that the same type of data and information that was necessary to propose eRIN provisions for the light-duty fleet will soon be available for at least the school bus fleet, if not other portions of the medium- and heavy-duty market. While we are not proposing a program that will include medium- and heavy-duty electric vehicles in this rulemaking, we welcome public comment on this proposal, as well as on the data and information that would be needed to incorporate them in the future.

ii. Non-Road Vehicles, Engines, and Equipment

Another component of the transportation sector that already has considerable electrification and could experience growth in the future is nonroad vehicles, engines, and equipment. However, at this time we are proposing to exclude nonroad vehicles, engines, and equipment from generating eRINs for both regulatory and policy reasons. As with medium-duty and heavy-duty vehicles, at this time there would be significant challenges associated with extending an eRIN program to nonroad vehicles, engines, and equipment, related in large part due to their diversity and the associated difficulty in procuring the necessary data. Nonroad vehicles, engines, and equipment include everything from small weed trimmers and leaf blowers to airport ground equipment to large excavators, all of which have different market structures and different use cases for electricity. This makes it challenging to ensure we have the data and information necessary to develop the regulatory program in terms of both ensuring the appropriateness of programmatic responsibilities and creating eRIN generation calculations which accurately reflect the use of renewable electricity in these engines. In addition, there is some question as to whether under the RFS program, off-highway vehicles, engines, and equipment with electric motors would meet the definition of nonroad vehicles and engines under our regulations at 40 CFR 80.1401 and whether fuel used in nonroad vehicles, engines, and equipment is used as ''transportation fuel.'' We seek comment on the exclusion of renewable electricity used in non-road vehicles, engines, and equipment under this proposal.

3. Geographic Scope

Clean Air Act section 211(o)(2)(A)(i) requires that the RFS program ''ensure that transportation fuel sold or introduced into commerce in the United States (except in non-conterminous States or territories), on an annual average basis, contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and

[234] *https://calstart.org/wp-content/uploads/2022/07/ZIO-ZETs-June-2022-Market-Update.pdf*

biomass-based diesel.'' [235] Thus, under the RFS program generally, renewable fuel that is produced in or imported into the 48 continuous United States or Hawaii is eligible to generate RINs. Additionally, EPA has imposed regulatory requirements to ensure that eligible fuel is actually used as transportation fuel in the conterminous 48 states or Hawaii.[236]

We evaluated the appropriate geographic scope of an eRIN program against this statutory backdrop. There are two aspects of geographic coverage to consider: the boundaries within which renewable electricity generation can occur and where light-duty electric vehicles using that electricity must be located. We address the first here. For liquid biofuels, this is addressed by focusing primarily on where the renewable fuel was produced or imported while accounting for any renewable fuel that is exported. However, as discussed in Section VIII.B, electricity has some unique characteristics that make determining the appropriate geographic scope a challenge, notably, that (1) once qualifying renewable electricity is loaded onto the commercial electrical grid serving the conterminous U.S. it is indistinguishable from non-qualifying electricity, and (2) electricity withdrawn from a commercial electrical grid serving the conterminous U.S.as myriad uses, most of which are not for transportation. As a result, once renewable electricity is loaded onto a commercial electrical grid serving the conterminous U.S., it is necessary to rely on a series of contractual relationships, rather than direct tracking, to connect renewable electricity to transportation end use. We discuss the implications of these two factors for the geographic scope of our proposed eRIN program in the subsections that follow. See Section VIII.F.4 for further explanation.

a. Connection to Grids in the Conterminous United States

Electricity used by customers in the conterminous United States is transmitted primarily via three interconnections—the Eastern, Western and, Texas Interconnections; the Eastern Interconnection also extends into Canada and the Western Interconnection covers parts of Canada and Mexico.[237] Once renewable electricity generated from qualifying biogas is loaded onto a commercial transmission grid that is part of one of these Interconnections, it is impossible to distinguish that renewable electricity from electricity of any other origin. Additionally, given that EVs are not geographically constrained to charging on just one Interconnection, it would be arbitrary to limit the scope of the eRIN program thusly. We are therefore proposing that any electricity that is produced from qualifying biogas and transmitted via an interconnection supplying consumers in the conterminous United States is eligible to participate in the program (*i.e.,* is eligible to be contracted for to generate eRINs). Furthermore, as discussed in Section VIII.F.5.a, we are proposing that any EV that is registered by a state in the conterminous 48 states be eligible to generate eRINs.

Additionally, as with other renewable fuel production under the RFS program, foreign produced renewable electricity could also qualify for eRIN generation. As noted above, the interconnections extend beyond U.S. borders to Canada and Mexico and electricity is regularly traded across these international borders to and from transmission networks serving customers in the conterminous United States. Consequently, we are proposing that electricity generators using qualifying renewable biogas in Canada and Mexico that are capable of establishing bilateral contracts with a load serving entity in the conterminous United States be allowed to participate in the program. That is, we are proposing that electricity generators using qualifying renewable biogas that are capable of selling their electricity for use in the conterminous United States are eligible to participate. Any foreign producers in Canada or Mexico wishing to participate would be subject to the requirements described in Section VIII.Q in addition to satisfying the generally applicable requirements for participation in the eRIN program as a renewable electricity generator. We request comment on whether defining the geographic scope of the program to allow electricity generators using qualifying biogas in Canada and Mexico that are capable of serving the conterminous United States is appropriate. We also request comment on alternative approaches to defining the geographic scope of the program, including descriptions of how any alternatives are consistent with the requirement that RIN-generating renewable fuel be produced or imported for use in the conterminous United States (see Section VIII.E.3.c below for discussion of Hawaii).

Under this proposal, renewable electricity produced in other foreign countries not meeting the aforementioned criteria would not qualify under the program. Unlike other fuels, there is no way to import renewable electricity produced in foreign countries into the conterminous United States unless they are connected to transmission networks serving electricity to customers in the conterminous United States. That is, there is no way renewable electricity can be used for transportation in the United States unless it is placed on a transmission grid that serves U.S. customers. We also seek comment on our proposed determination that renewable electricity produced in foreign countries, other than renewable electricity produced in the circumstances described in the previous paragraph, cannot qualify under the program.

b. Hawaii

While our proposed approach for the conterminous U.S. both allows for the connection of renewable electricity generation to transportation use and provides for maximum flexibility for the eRIN program, the State of Hawaii uses geographically separate electricity transmission systems. Therefore, under the proposed approach, it cannot be assumed that renewable electricity generated in Hawaii is used to charge the U.S. fleet of electric vehicles as a general matter. Similarly, it could not be assumed that EVs operated within Hawaii are fueled on renewable electricity supplied from qualifying electrical generation occurring outside of Hawaii. Consequently, under our proposed eRIN program structure, electrified vehicles registered in Hawaii would be unable to participate in the proposed eRIN program at this time. Similarly, electricity generators in Hawaii would also be unable to participate in the proposed eRIN program at this time. While we acknowledge that there most likely are both electricity generation from qualifying biogas and light-duty electric vehicles in Hawaii and that it may be possible to connect the two, at this stage in the eRIN program development we believe it would significantly increase the implementation burden and program complexity to include

[235] The Clean Air Act requires that the RFS program apply to the conterminous 48 states, and permitted Hawaii, Alaska, and U.S. territories to opt in. To date, only Hawaii has opted in. EPA refers to conterminous 48 states and Hawaii the ''covered location'' under the RFS program (see the definition of ''covered location'' in 40 CFR 80.1401).

[236] Note that for any renewable fuels that are exported from the covered location, the exporter of the renewable fuel must satisfy an exporter RVO under the regulations at 40 CFR 80.1430.

[237] See *https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act-0.*

renewable electricity generated and used as a transportation fuel in Hawaii. Due to the increase in implementation burden and program complexity, inclusion of Hawaii into the eRIN program could ultimately delay the start date of the program.

We request comment, including data and other information, on these limitations and methods by which electrified vehicle and electricity generators using qualifying renewable biomass in the state of Hawaii could be incorporated into the program. In particular, we request comment on the efficacy of setting up a separate parallel program just for the state of Hawaii, including whether it would necessitate manufacturers to have a separate fleet and records just for Hawaii.

4. Timing and Start Date

The expansion of the RFS program to include new regulations governing the generation of eRINs will result in many new parties registering and participating for the first time. The process of registering these parties, and of them becoming familiar with and complying with the RFS program, will require significant time and resources, both for participants and the EPA. Consequently, we do not believe that it is realistically feasible for the generation of eRINs to be permitted in 2023. Instead, we are proposing to permit eRIN generation beginning on January 1, 2024.

A January 1, 2024 start date would serve a number of important purposes. First, it should allow eRIN generation to align temporally with the proposed volume requirements, which include a projection of eRIN generation. That is, it would be inappropriate for eRIN generation to begin in the year prior to or in the year following the year in which a projection of eRIN generation is included in the determination of the applicable standards. Were eRIN generation to lag the volume requirements, there could be a significant shortfall in cellulosic RINs which would disrupt the market and could potentially necessitate a waiver action. Conversely, were eRIN generation to proceed the volume requirements, there could be a significant oversupply of cellulosic RINs that would likely depress RIN prices, adversely affecting participation. Second, it would allow regulated parties more time to get their engineering reviews conducted, register, and develop their internal operating and compliance systems to comport with the new regulations in an orderly manner thereby avoiding the inevitable problems that would otherwise be expected if done in haste. Third, the proposed January 1, 2024 start date would allow parties interested in participating in the program or impacted by the program more time to establish the necessary contractual relationships necessary to implement the new program. Fourth, the proposed start date would allow EPA time to modify EMTS and evaluate registration requests as they are submitted to the agency. Finally, the proposed start date would align the start of the program with the existing calendar year structure of the RFS program. Based on our experience implementing the RFS program, this alignment makes the submission of quarterly and annual reports more straightforward and results in a smoother implementation than a mid-year effective date because compliance demonstrations under the RFS program are built around a compliance period that begins on the first day of the calendar year.

We recognize that some parties believe that EPA could include a projection of eRINs in the applicable 2023 standards, and thus permit eRINs to be generated in 2023. However, it is highly uncertain whether the parties necessary to generate eRINs—biogas producers, renewable electricity generators, and OEMs—will be prepared to participate in 2023. It is also not clear if and how many contracts would be established between participants in 2023. As a result, a projection of eRIN generation for 2023 in this rulemaking would be considerably less accurate than our projections for 2024 and 2025, potentially resulting in a substantial oversupply or shortfall in the availability of cellulosic RINs with the attendant consequences described above.

Although we have confidence that at least some parties will be registered and contracts established by January 1, 2024, there is a significant amount of uncertainty in the number of biogas production facilities and renewable electricity generation facilities that will be able to arrange for independent third-party engineering reviews and establish contractual relationships with eRIN generators to enable RIN generation to begin on that date. As noted in DRIA Chapter 6, we estimate that there are over 500 landfill-to-electricity projects and over 200 digester-to-electricity projects already in operation. A large majority of the electricity output from these facilities would be needed to meet the electricity demands of the national light-duty EV fleet. However, prior to their production being used to generate RINs, each of these projects would have to arrange for an independent third-party professional engineer (PE) to conduct an engineering review. Based on the currently anticipated timing for signature and effective date of the final rule establishing an eRINs program, industry will only have three to four months before the proposed start of the eRIN program on January 1, 2024, to conduct engineering reviews, submit registration submissions, and make contractual arrangements for eRIN generation. As discussed in the DRIA, we estimate that, on average, the current pool of PEs conducts around 300 engineering reviews per year. Most of these occur in the second half of the year prior to the January 31 deadline for 3-year registration updates. Because of the overlap between eRIN implementation and the typical 3-year registration update cycle, the number of PEs needed to both complete the registration updates and conduct reviews for the new eRIN participants would need to more than double to accommodate the electricity demands of the entire national light-duty EV fleet in 2024. Additionally, first-time engineering reviews are more difficult than 3-year updates because the facility has not previously been visited by a PE and the regulated parties (biogas producers and renewable electricity generators) are less acquainted with the regulatory requirements. The time and effort we anticipate it would take to conduct these reviews would be compounded by the fact that because the eRINs regulatory provisions would be new, the PEs themselves would not be acquainted with the new regulatory requirements, which would increase the amount of time for them to complete their reviews. For these reasons, it is highly unlikely that industry would be able to develop and submit the registration materials needed to register the hundreds of facilities to cover all of the electricity used in the light-duty EV fleet at the start of the eRIN program.

We thus believe the volumes of eRINs that will be produced in 2024 and 2025 will be defined by the pace at which biogas electricity facilities will be able to complete their engineering reviews and enable eRIN generation. We have projected potential eRIN volumes at the start of the program based on how many and when such facilities could be registered. Using these estimates, we can estimate the amount of eRINs that would be generated for 2024 and 2025 based on reasonable assumptions for how quickly facilities could become registered and produce qualifying biogas and renewable electricity. The volumes we are proposing based upon our assessment are 600 million RINs from renewable electricity in 2024 and 1.2

billion RINs from renewable electricity in 2025. We discuss the methodology for these volumes in DRIA Chapter 6, and we seek comment on our approach and assumptions. We also seek comment on ways to streamline the registration process to increase the number of facilities that we are able to bring into the program by January 1, 2024.

We also recognize that EPA may need more time to review and accept the initial registration submissions for the potentially hundreds of new facilities that would be able to participate in the program by January 1, 2024. As such, we are considering providing parties wishing to participate in the eRIN program additional flexibilities in the case where they are able to submit timely registration requests, but EPA is unable to accept those requests prior to January 1, 2024, if certain conditions are met. We describe this potential flexibility in more detail in Section VIII.K.2.

F. Proposed Program Structure for Light-Duty Vehicles

This section describes the proposed program governing the generation of eRINs. The proposed regulations in new subpart E of 40 CFR part 80 would implement the program as described in this section. Topics covered in this section include key participants, identification of the party to be the RIN generator, and the requirements for RIN generation and program participation. Section VIII.H provides a discussion of the alternative program structures that we considered, including approaches wherein parties other than the OEM would generate the eRINs. We discuss in greater detail the specific regulatory requirements in Sections VIII.L through R.

1. Contract-Based Structure for eRIN Program

As discussed in Section VIII.B, electricity on the commercial electrical grid serving the conterminous U.S. is fungible. This fact directly informs the proposed eRIN program design to ensure renewable electricity is used as transportation fuel. Renewable electricity that is generated from qualifying biogas at an EGU is loaded onto a commercial electrical grid serving the conterminous U.S. and at that point it becomes impossible to distinguish the renewable electricity from electricity generated from any non-qualifying energy sources. This, in turn, makes it impossible to track the physical renewable electricity or to determine its ultimate disposition. Therefore, rather than tracking physical quantities of electricity from generation to disposition, regulatory and voluntary programs for the use of renewable electricity typically use a contractual relationship between a generator and end-user (or another party in the electricity value chain) as a proxy. Examples of this type of contractual-based program relationship include the Renewable Portfolio Standards discussed in Section XIII.H.2 and the California LCFS Program discussed in Section XIII.H.1.

As explained previously, the CAA's definition of renewable fuel requires that qualifying renewable electricity be both produced from renewable biomass and used for transportation. Given the impossibility of tracking physical electricity from its point of generation into electric vehicles, EPA's proposed eRIN program relies on a contract-based framework similar to the RFS program's current approach to CNG/LNG, as well other renewable electricity programs. That is, we are proposing to require eRIN generators to demonstrate that the electricity used as transportation fuel was produced from renewable biomass under an EPA-approved pathway through, among other things, the existence of a bilateral contract between the eRIN generator and renewable electricity generator. This contract, which we refer to as the RIN generation agreement, would establish the exclusive ability of the RIN generator to generate RINs for a given quantity of renewable electricity produced from qualifying biogas at a renewable electricity generation facility. The mechanism of RIN generation agreements would ensure that renewable electricity produced from qualifying biogas is able to generate RINs only once, and that only one party, in this case the eRIN generator, would be able to claim that quantity of renewable electricity as transportation fuel.[238] We believe that, given the unique circumstances of electricity used as a transportation fuel, relying on RIN generation agreements is a reasonable approach to meeting the Clean Air Act's requirement that renewable fuel be produced from renewable biomass and used for transportation. As explained above, once electricity is loaded on a commercial electrical grid serving the conterminous U.S., it is impossible to track specific quantities—renewable electricity is entirely indistinguishable from fossil-based electricity. Thus, any eRIN program that involves the use of a commercial electrical grid serving the conterminous U.S. will necessarily rely on a contractually based mechanism to satisfy the statutory requirements.

We recognize that this type of contractual mechanism would not be necessary for an EGU that generates electricity from qualifying biogas and distributes it via a closed, private, non-commercial system from which EVs are charged.[239] However, establishing an eRIN program that requires a closed, private, non-commercial system would effectively limit participation to projects where a biogas-powered EGU is collocated with a fleet of EVs (*e.g.,* a municipally owned landfill that has a co-located EGU and a dedicated mini-grid that is used to charge a fleet of EVs). We anticipate these circumstances would be rare and that an eRIN program predicated on this approach would capture only a very small portion of potentially qualifying renewable electricity that is used for transportation. Given the goal of the RFS program to increase the use of renewable fuels and replace or reduce the quantity of fossil fuel present in transportation fuel, we do not believe an eRIN program that provides credit to a very narrow portion of the potentially qualifying renewable fuel serves Congress's purpose. Thus, we believe it is reasonable to interpret the definition of renewable fuel in Clean Air Act 211(o)(1)(J) to allow eRIN generators to demonstrate that renewable electricity is used for transportation through the contractually-based framework described in this notice. We request comment on this proposed framework for linking renewable electricity produced from qualifying biogas to transportation use.

2. eRIN Program Participants

As discussed in Section VIII.B, there is a wide variety of parties involved in the eRIN generation/disposition chain, including the biogas producer, the biogas and RNG distributors, the

[238] We note that under our proposal, RIN generation agreements would cover 100 percent of renewable electricity generation for a facility except for any electricity generation from the facility that is sold outside the RFS program. In other words, our proposal would not require that all electricity generated at a facility be part of the RFS program, but would rather only allow RIN generation for renewable electricity covered by a RIN generation agreement.

[239] EPA's existing regulations contain a framework for RIN generation for electricity distributed only via a closed, private, non-commercial system at 40 CFR 80.1426(f)(10)(i). To date, due to the very limited amount of renewable electricity that could be used in a closed system, the closed, private, non-commercial system approach for eRIN generation has not been the focus of registration requests and stakeholder interest for eRIN generation. Instead, registration requests and stakeholder interest has focused on the use of renewable electricity distributed via a commercial electrical grid.

renewable electricity generator, the electricity transmission and distribution owners, the EV owners, charge station owners, and OEMs. As a result, there are a variety of options for how to structure a program that leverages the incentives provided by eRINs to increase the use of renewable electricity in transportation. However, some participants are better positioned than others to ensure that biogas used to generate renewable electricity is used as transportation fuel in a manner consistent with the Clean Air Act and EPA regulatory requirements. We sought to include elements in our program that we believed could both maximally incent the generation of eRINs and ensure that the eRINs represent renewable electricity used as transportation fuel. Ultimately, as discussed in VIII.G., we believe the goals described in Section VIII.C would best be served by focusing the eRIN program requirements on biogas producers, renewable electricity generators, and EV manufacturers (OEMs), while relying on other public and private efforts to address the activities of other market participants in areas such as charging infrastructure and electricity transmission.

Our proposed eRIN program includes a comprehensive set of regulatory requirements for the biogas producers, the renewable electricity generators, and the OEMs. We believe that the proposed regulation of these three core parties is the bare minimum needed to ensure that the eRIN program results in the production of renewable electricity produced from biogas and used as transportation fuel in a manner consistent with the Clean Air Act. Biogas producers are the party best able to demonstrate that biogas was produced from qualifying renewable biomass. Renewable electricity generators are the party best able to ensure that their electricity is produced in a manner consistent with an EPA-approved pathway in Row Q or T in Table 1 to 40 CFR 80.1426. OEMs, as we discuss in more detail shortly, are the party best able, given our programmatic goals and design criteria, to demonstrate the amount of renewable electricity used as transportation fuel in electric vehicles.

We expect that these three parties would share, through contracts outside of EPA's regulatory regime, the revenue from eRINs, which we believe would grow the use of renewable electricity as transportation fuel in the coming years. OEMs are heavily invested in the success and proliferation of EVs in an increasingly electrified world; many OEMs have stated publicly their intention to electrify an ever-growing share of their manufactured fleets. For biogas producers and renewable electricity generators, the ability to acquire high-value offtake agreements from the increased demand for their products would send the requisite market signals to ensure continued growth and investment of renewable electricity produced from biogas as a transportation fuel, thereby supporting the goals of the RFS program.

We are not proposing to directly regulate other parties in the eRIN generation/disposition chain. We believe inclusion of the biogas producers, renewable electricity generators, and OEMs in the proposed structure would be sufficient to ensure that renewable electricity was produced from qualifying biogas and used as transportation fuel. We also believe that regulating additional parties, *e.g.,* charging infrastructure owners or transmission owners/operations, would be unnecessary and would impose a regulatory burden on those additional parties for no additional value to the program.

3. eRIN Generator

Having identified the three core parties, it is necessary to designate which party, or parties, will be allowed to act as a generator of eRINs. While we believe it may be reasonable to designate any one of these parties as the eRIN generator, we are proposing for reasons discussed in Section VIII.G that only OEMs be eligible to generate eRINs.

While EPA's regulations could specify that any or any combination of these parties as the eRIN generators, we are proposing that only one party in the chain serve as the RIN generator. We are proposing only one RIN generator because it would allow for us to establish a more-focused set of regulatory requirements on the core parties in the eRINs generation/disposition chain that we believe would reduce program complexity and associated implementation burden. As discussed in more detail in Section VIII.G and Section IX.I, for biogas to CNG/LNG under the existing regulations, we have established regulatory provisions that allow for any party in the CNG/LNG generation/disposition chain to generate the RINs. In order to allow for any party to generate RINs for renewable CNG/LNG, we promulgated a flexible, but resource-intensive set of requirements based on the establishment of contracts between all parties in the CNG/LNG generation/disposition chain at registration and the creation of additional contracts, affidavits, and documentation for specific volumes of biogas to demonstrate that the biogas was used as transportation fuel. While these regulatory provisions have worked for the relatively low number of facilities that we have registered for biogas to CNG/LNG under the current regulations, we believe that it is not a sustainable model for eRINs which will have several times more biogas production facilities and hundreds of additional renewable electricity generation facilities than currently included in the RFS program. By specifying a single party (*i.e.,* the OEM) as the eRIN generator in the eRINs generation/disposition chain, we can only require the creation and transfer of the specific information from each core party to the eRIN generator and provide certainty over how such information is reported, transferred to other parties, and reviewed by third parties for verification. This approach would significantly streamline what is required for each individual party in the eRINs distribution/generation chain and make the program much more straightforward for EPA to implement and oversee.

Our proposed approach would establish a single point for eRIN generation which would enable us to ensure the validity of eRINs. As discussed in Section VIII.C.6, based on our experience implementing our current regulations for RNG under which RINs can be generated by any party in the RNG generation/disposition chain, we believe that specifying one party as the eRIN generator can help minimize program complexity and thereby reduce associated implementation burden for EPA and regulated parties. OEMs are uniquely positioned amongst the three parties because they are directly invested in the growth of electric vehicles. As discussed in DRIA Chapter 6.1.4, the fleet size and growth rate of electric vehicles is currently a limiting factor for increasing the use of renewable electricity used as renewable fuel. Therefore, to achieve the statutory goal of increasing renewable fuel used as transportation fuel in United States, it is reasonable that OEMs not only be a part of the eRIN generation/disposition chain as discussed above, but also be the RIN generator. Given the high level of competition among OEMs, we believe that they would have an incentive to use the eRIN revenue to lower the purchase price of EVs, thereby increasing EV sales and ultimately the penetration of renewable electricity into U.S. transportation fuel in support of the primary goal of the RFS program to increase the use of renewable fuel in transportation.

Identifying OEMs as the eRIN generator would also have benefits for

implementation of the program. For instance, the relatively small number of OEMs which would need to be registered would simplify the program implementation, allowing it to be implemented in 2024. Moreover, the OEMs have the staff, resources, background, and expertise necessary to take on the compliance oversight responsibilities needed to generate eRINs. Unlike many renewable electricity generators and charge station owners, even the small number of small business OEMs have a long history of complying with EPA regulations. Finally, placing the OEMs as the RIN generator allows for a simpler compliance oversight design by ensuring that the information needed to carry out an audit to verify the validity of RINs is entirely at one location. Additional discussion of the ways in which the OEM as the eRIN generator fulfills the statutory goal of increasing the supply of qualifying renewable electricity used as transportation fuel is provided in Section VIII.G.

4. Overview of Our Proposed eRIN Program

Having identified biogas producers, renewable electricity generators, and light-duty vehicle OEMs as the directly regulated parties in the proposed eRIN program, with OEMs being the eRIN generator, their roles can be more precisely defined as follows:

Biogas producers (*e.g.,* landfills, agricultural digesters, and wastewater treatment plant digesters) would produce biogas under the EPA-approved pathways for biogas to electricity under the RFS program. Renewable electricity generators would either use biogas directly supplied to their EGUs (*e.g.,* a landfill or digester with an onsite EGU) or procure RNG (along with its assigned RIN as proposed in Section IX.I) from the natural gas commercial pipeline system to generate renewable electricity. The OEMs would determine the electricity consumption of their vehicles in the in-use fleet (including legacy and new electric vehicles), and acquire through a bilateral contract with the renewable electricity generators the exclusive RIN-generating ability for the renewable electricity generated by the renewable electricity generators, or ''RIN generation agreements,'' that is sufficient to cover their fleet's in-use electricity consumption. OEMs would then be able to generate the eRINs representing the lesser of the quantity of electricity used by their fleets and the renewable electricity generated from renewable electricity generator(s) under RIN generation agreements. In other words, the OEM could not generate RINs beyond the amount of renewable electricity generated by renewable electricity generators under their RIN generation agreements. However, it could only generate RINs up to the amount of electricity used by its fleet. Obligated parties (*e.g.,* refiners, importers, and blenders) would purchase cellulosic or advanced eRINs from the OEMs to comply with their RVOs just as they purchase RINs from other parties today under the RFS program. Each party in this eRIN generation/disposition chain would be subject to compliance obligations as described more fully in Sections VIII.L through R.

An important consideration in developing our proposed eRIN program was building a program we are capable of implementing in the near term, based on our existing implementation capabilities, thus reducing the amount of time needed for us and the regulated community to actualize the program. Significant deviation from our current capabilities (*e.g.,* new information collection systems to collect large amounts of charging event data) would require significant additional time to develop and deploy such capabilities, further delaying eRIN program implementation. We discuss the alternative program structures that we considered in Section VIII.H.

5. eRIN Generation

a. OEM RIN Generation Responsibilities

Under our proposal, OEMs would be responsible for determining the quantity of eRINs that they can generate based on the amount of renewable electricity produced from qualifying biogas used in light-duty electric vehicles. To this end, we are proposing to require each OEM to submit to the EPA the quantity of light-duty electric vehicles they manufactured (BEVs and PHEVs) which are legally registered in a state in the conterminous 48 states, and thereby part of the in-use fleet each quarter. As part of this submittal, OEMs would be required to designate the quantity of both BEVs and PHEVs in their fleet along with technical information about the performance characteristics of each model in their fleet. We refer to this demonstration as the process of the OEM determining their fleet size and disposition for RIN generation. It is our understanding that OEMs already have access to the necessary information to support this approach, but seek comment on the extent to which this is the case.

Once an OEM has determined its quarterly fleet size and disposition, this inventory of registered light-duty electric vehicles would be used to calculate the quarterly quantity of electricity used as transportation fuel. Using the proposed formulas and prescribed factors, the OEM would translate their fleet size and disposition data into a quantity of megawatt hours of electricity used by the fleet on a quarterly basis.[240] The prescribed factors being proposed include an average EV efficiency value of 0.32 kWh/mi, annual eVMT for BEVs of 7200 mi/yr, and a formula which calculates the applicable eVMT for PHEVs based upon the all-electric range of a given PHEV model. This set of prescribed factors facilitates the translation of an OEM's fleet size and disposition into the maximum quantity of kilowatt hours eligible for eRIN generation. Further explanation of this is provided in a memorandum to the docket[241] and RIA Chapter 6.1.4. We request comment on the individual values and the appropriateness of these formulas and prescribed factors.

This set of data for RIN generation represents a top-down approach which, as discussed in Section VIII.D.2.b, would have the advantage of simply and easily capturing the full amount of renewable electricity produced from qualifying biogas used in transportation. More specifically, the approach captures the entire in-use fleet (*i.e.,* both new electric vehicles and legacy electric vehicles without telematics equipment) and all vehicle charging (*i.e.,* both public and private charging), thereby providing the maximum amount of and incentive for renewable electricity used as renewable transportation fuel under the RFS program. The only transportation use data needed to be collected and reported for the purpose of RIN generation is the OEM's fleet size and disposition.[242] Consequently, this approach provides minimal opportunity for fraud or system gaming, a simple means for EPA to provide effective oversight, and would provide EPA with a predictable basis for projecting future renewable electricity use.

The proposed program differentiates between two types of electrified vehicles: full battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). All BEVs, which rely

[240] The proposed formulas and prescribed factors for eRIN generation are described in the proposed 40 CFR 80.140.

[241] U.S. EPA (2022), ''Examples of RIN generation under the proposed RFS eRIN provisions.''. Memorandum to Docket No. EPA–HQ–OAR–2021–0427, November 22, 2022.

[242] Additional data collection and reporting requirements are proposed as discussed in Section VIII.F.6. below to support continual updates of the prescribed factors in the formulae to ensure accuracy over the long term.

entirely upon electricity for all vehicle miles travelled, would be treated in a uniform fashion for the purposes of calculating their renewable electricity consumption. PHEVs, which have both an internal combustion engine and an electrified drivetrain, must have the electrical fraction of their energy consumption separated from that provided by fossil fuels. As described in DRIA Chapter 6.1.4.1, we are proposing to use the all-electric range of each unique PHEV model in order to determine the fraction of total vehicle miles travelled powered by electricity. Further disaggregation among BEVs and PHEVs may eventually be possible to improve the precision of RIN generation as more light-duty vehicle subsectors become electrified, but the available data does not currently allow for this.[243] See Section VIII.F.6 for further discussion regarding OEM vehicle data collection and reporting requirements that would be used for future program enhancement.

In order to be able to generate the calculated maximum eRINs for its light-duty electric vehicle fleet, we are proposing that each OEM would procure a sufficient quantity of renewable electricity under RIN generation agreements for which the OEM has the exclusive ability to generate RINs.[244] We anticipate that OEMs would enter into RIN generation agreements with renewable electricity generators who in turn make the demonstration that the renewable electricity has been generated from qualifying renewable biogas. In determining the quantity of renewable electricity able to be used as transportation fuel, OEMs would be required to account for line losses and the typical charging efficiency of electric vehicles. We anticipate that in order for OEMs to be able to generate the maximum amount of RINs that they calculated using their fleet size and disposition, they would have to contract for 24.2 percent more qualifying renewable electricity than they anticipate would be consumed by the fleet in any given quarter to account for line losses (5.3 percent [245]) and charging efficiency (85 percent [246]). We request comment on the values selected for line losses and vehicle charging efficiency. For more information on this calculation see the docket memorandum containing examples of RIN generation,[247] the proposed regulations at 40 CFR 80.140, and DRIA Chapter 6.1.4.

We are proposing that RIN generation would occur on a one quarter lag from the use of the transportation fuel itself. This lag would provide sufficient time for the collection of the requisite fleet size and disposition data along with the renewable electricity generation data from the renewable electricity generators. Provided that this use and procurement data meets the qualifications outlined in the regulations, the OEM would be able to generate the maximum quantity of RINs calculated for its fleet using the revised equivalence value for electricity discussed in Section VIII.I. In instances where the OEM fails to procure an adequate quantity of renewable electricity to meet the maximum quantity of electricity used as transportation fuel calculated for its fleet, RIN generation would be limited to the quantity of renewable electricity procured.

b. Renewable Electricity Procurement

Under our proposed program structure, an OEM would obtain the ability to generate RINs by establishing a RIN generation agreement with a renewable electricity generator for the total amount of qualifying renewable electricity produced at the renewable electricity generator's facility.[248] Renewable electricity generators would transmit the information on the renewable electricity they generate under the RIN generation agreement to the OEMs, who would then use the information to demonstrate that the electricity used by its fleet was qualifying renewable fuel and to generate eRINs.

We envision that the RIN generation agreements would not affect any direct purchase agreements between the renewable electricity generator and distributors of the renewable electricity. That is, an OEM would be procuring permission to generate eRINs representing the quantity of qualifying renewable electricity covered by the RIN generation agreement, but would not need to own that quantity of renewable electricity nor take possession of it. Furthermore, as discussed in Section VIII.F.5.g., we do not intend for the sale or transfer of RIN generation agreements by the renewable electricity generator to preclude them from participation in other state or local programs (LCFS, RECs, etc.) premised off of environmental attributes other than the demonstration that the electricity was produced from qualifying renewable biomass.

We are also proposing that the vintage of eRINs would be the year that the renewable electricity was generated. For example, RINs generated to represent renewable electricity generated in December 2024, would be 2024 RINs. This approach is consistent with RIN generation for all other renewable fuels currently under the program. For example, RINs generated for denatured fuel ethanol are generated as the vintage year of RIN that the denatured fuel ethanol was produced or sold, not the year in which it was used as transportation fuel.

We are proposing to deem the net electrical output (gross electrical output, less balance of plant loads) of the renewable electricity generated by the renewable electricity generator to be eligible to eligible for the generation of eRINs so long as the renewable electricity was generated from qualifying biogas and was connected to the commercial transmission grid serving the conterminous U.S. Under our proposal, it would not matter if the facility where the renewable electricity generator is located also consumes electricity onsite, impacting the quantity of renewable electricity generation that gets placed on the grid. We considered limiting an renewable electricity generator's eligible renewable electricity for RIN generation to the net amount of renewable electricity production, after accounting for use of electricity use at the facility level, as opposed to the renewable electricity generator's net electricity production. However, in many cases a renewable electricity generator is or could be connected directly to a transmission grid with electricity flowing fungibly to and from the facility. Therefore, we could not come up with a reasonable means of restricting a facility's net renewable electricity output. We seek comment on this approach and other potential options.

c. Frequency of RIN Generation

For most renewable fuels in the RFS program, RINs are generated on a batch basis in concert with production or sale of the renewable fuel. Under the existing regulations, a RIN generator may generate RINs for a batch of renewable fuel that represents up to one

[243] Discussion on current disaggregation of PHEVs and BEVs presented in Chapter 6.1.4.1 of DRIA.

[244] Under our proposal, the renewable electricity could only be contracted and used once within the RFS program. However, as discussed in Section VIII.F.5.g, it could continue to be used for purposes outside of the RFS program under certain conditions (*e.g.,* for RECs or LCFS credits).

[245] See DRIA Chapter 6.1.4.

[246] See DRIA Chapter 6.1.4.3.

[247] ''Examples of RIN generation under the proposed RFS eRIN provisions,'' available in the docket for this action.

[248] Under this proposal, and for purposes of this preamble, we call the ability to generate RINs that an OEM obtains from a renewable electricity generator a ''RIN generation agreement.''

calendar month's worth of production or importation. Within this general structure, however, each renewable fuel has adopted different approaches for the frequency of RIN generation based on how those renewable fuels are produced, distributed, and used. For example, for denatured fuel ethanol, ethanol producers typically generate RINs for each tanker truck or rail car worth of denatured fuel ethanol. For biogas to renewable CNG/LNG, RIN generators generate RINs on a monthly basis for the amount of biogas-derived renewable CNG/LNG that the RIN generator can demonstrate was used as transportation fuel for that month. For RNG specifically, the RNG is demonstrated to have been used as transportation fuel when a quantity of gas corresponding to the contracted for quantity of RNG is physically withdrawn from the pipeline and demonstrated through documentation to have been used as transportation fuel. The RIN generation procedure for biogas to renewable CNG/LNG is different than for denatured fuel ethanol because the regulations require that the RIN generator must demonstrate that a volume of biogas has been used as transportation fuel prior to the generation of RINs.

Similarly, in the case of eRINs, as for biogas to renewable CNG/LNG, we are proposing that before a RIN could be generated, it must also be connected to use as transportation fuel. However, unlike biogas to renewable CNG/LNG, there is no obvious time period within which this occurs as it is the accounting action itself which, in the context of a fungible electricity supply, connects the electricity generation to use as transportation fuel, not a physical connection. This fact allows for a variety of possible time periods for RIN generation. After weighing various options, we are proposing that OEMs would generate RINs on a quarterly basis. We believe that quarterly RIN generation would allow sufficient time for renewable electricity generators to prepare information related to that generation for their facilities for transmittal to OEMs for RIN generation.

We considered proposing annual RIN generation, but concluded that it would not be appropriate. Even though we believe annual RIN generation could provide accurate renewable electricity generation and use information, we believe it is important to allow for periodic RIN generation throughout the year so that obligated parties could use publicly posted RIN generation information to develop compliance strategies for the RFS standards. If we only had one annual eRIN generation event, the number of eRINs generated would not be known until likely the end of February leaving only the month of March for obligated parties to obtain and retire the eRINs for compliance. We do not believe this is enough time and could cause unnecessary disruptions to the generation, transfer, and use of eRINs. Furthermore, annual RIN generation would likely delay to an unacceptable degree the flow of revenues among market participants, undermining the necessary investment needed to grow renewable electricity volumes.

We also considered proposing monthly RIN generation. Under the current provisions for biogas to renewable CNG/LNG, parties that generate RINs for biogas do so on a monthly schedule. While we believe monthly eRIN generation would provide obligated parties plenty of information to develop adequate compliance strategies to meet their RVOs, we believe that renewable electricity generators and OEMs may have unnecessary burdens associated with this more frequent RIN generation. As described in the docket memorandum providing examples of eRIN generation, the best information regarding vehicle size and fleet disposition is already available on a quarterly basis. If we were to make RIN generation more frequent, OEMs would have to convert quarterly information to monthly information which may limit the information's precision.

We are also proposing that OEMs would generate the RINs no later than 30 days after the end of the quarter. We are proposing this 30-day limit to help ensure that RINs are generated in a timely manner. This is particularly important after the fourth quarter where annual compliance demonstrations for obligated parties are due March 31. We believe it is important to provide enough time for the generation, transaction, and retirement of RINs, and we believe that 30 days is a reasonable time limit for RIN generation. This is consistent with our current experience with the biogas to renewable CNG/LNG pathway. Under the current biogas to renewable CNG/LNG pathway, most RIN generators generate RINs on a monthly basis after they have obtained the documentation needed to support RIN generation by the end of the following month. We believe that a shorter time period than 30 days would likely prove challenging for OEMs to gather all of the necessary information for RIN generation.

We seek comment on our proposed approach for quarterly eRIN generation and our allowance for OEMs to generate eRINs 30 days after the end of the quarter.

d. eRIN Separation

Under this proposed eRINs structure, OEMs would separate RINs generated for renewable electricity immediately after the RINs were generated in EMTS. This process for eRIN separation is consistent with the current regulatory text for how RINs are separated for renewable electricity.[249] Under the existing regulations, only after a party designates the electricity as transportation fuel and the electricity is used as transportation fuel can the party separate the RINs. Because the OEM has designated that renewable electricity as transportation fuel and demonstrated that it was used as transportation fuel in its EV fleet, the OEM would be required to separate the RINs under the existing regulations. Under the proposed eRINs program, the OEM would only generate the eRIN after it has procured renewable electricity data from the renewable electricity generator and demonstrated that the renewable electricity was used in its EV fleet. We are therefore not proposing to modify the approach for eRIN separation; however, we are proposing to modify the regulatory text at 40 CFR 80.1429(b)(5) to state more clearly that the party (*i.e.,* the OEM) that generates RINs for a batch of renewable electricity under the proposal must separate any RINs that have been assigned to that batch.

We seek comment on this approach to RIN separation for eRINs. We also note that while we are not proposing to change the basic approach to how RINs are separated for renewable electricity, we are proposing changes to how RINs are separated for biogas and RNG under the proposed biogas regulatory reform provisions discussed in detail in Section IX.I.

e. Renewable Electricity Generator Responsibilities

Under our proposed eRIN program, renewable electricity generators would be required to either be directly supplied from a biogas producer via a closed, private distribution system, or if the electrical generation was from RNG offsite from where the biogas was produced, the renewable electricity generator would have to retire RINs assigned to a volume of RNG injected into the natural gas commercial pipeline system as discussed in the proposed biogas regulatory reform provisions in Section IX.I. For renewable electricity generated from biogas supplied via a closed, private distribution system, the

[249] See 40 CFR 80.1429(b)(5).

proposed regulations would demonstrate at registration that their EGUs were directly supplied with biogas via a closed, private distribution system. For RNG converted to renewable electricity at an offsite EGU, the renewable electricity generator would retire assigned RINs to the RNG as described in Section IX.I, and then generate renewable electricity based on the amount of assigned RNG RINs retired. In both cases, a renewable electricity generator would identify at registration the OEM that entered into the RIN generation agreement for their renewable electricity.

To support the amount of renewable electricity produced from qualifying biogas transmitted into the commercial electrical grid serving the conterminous U.S., renewable electricity generators would submit periodic reports, keep records supporting renewable electricity generation, and undergo an annual attest audit.

f. Conditions on Renewable Electricity RIN Generation Agreements

We are proposing to allow light-duty OEMs to enter into RIN generation agreements with multiple renewable electricity generation facilities to ensure the procurement of enough renewable electricity to cover the electricity use of their light-duty electric vehicle fleet. By contrast, we are proposing that each renewable electricity generation facility would only be permitted to enter into a RIN generation agreement for its renewable electricity to a single OEM. We refer to this relationship as ''many-to-one,'' *i.e.,* many renewable electricity generation facilities enter into RIN generation agreements with one OEM. We believe this limitation would be necessary to ensure we would be able to maintain oversight, reduce implementation burden, and avoid the double-counting of renewable electricity. If we were to allow unlimited contractual transfers between the renewable electricity generators and the OEMs, we believe it would be much more likely that an amount of renewable electricity would be double counted (*i.e.,* two different OEMs generate RINs representing the same quantity of renewable electricity) because OEMs would likely be unaware that another OEM used that contracted renewable electricity to generate RINs.

Furthermore, while we believe that, in general, OEMs would need multiple EGU facilities' worth of renewable electricity to cover their vehicle fleet's electricity use, we do not anticipate that the reverse would be true. That is, we do not expect that a single renewable electricity generator would generate so much electricity that it would be in a position to provide enough renewable electricity to more than one OEM.

Similar to the recently finalized biointermediates program, we would allow renewable electricity generators to change the contracted OEM for a renewable electricity generation facility once per calendar year or more frequently subject to our approval. We would expect to allow a renewable electricity generator to change their contracted electricity for a facility in rare cases where an OEM went out of business or a natural disaster disrupted production for an extended period of time. Additionally, we expect that under our proposal OEMs would likely enter into a RIN generation agreement for renewable electricity for a period of time not less than a calendar year, and likely longer, in order to create certainty that the OEM could obtain enough renewable electricity to generate the full number of RINs for their fleet. Therefore, we do not believe that a renewable electricity generator would need to change the OEM that they have entered into a RIN generation agreement more frequently than once per calendar year.

We seek comment on this proposed many-to-one limitation for renewable electricity generators and on any alternative approaches. When providing comments suggesting an alternative, commenters should provide information on how such an alternative would allow for proper verification and oversight and avoid the double-counting of electricity.

g. Interaction With Other Environmental Credit Programs

The proposed eRIN regulations are designed to prevent the double counting of RINs under the RFS program and to ensure that renewable electricity for which RINs are generated is used for a single purpose—transportation fuel within the conterminous United States. However, we do not intend the proposed eRIN program to limit or preclude renewable electricity generators from participation in other state or local programs (*e.g.,* California's LCFS, state renewable portfolio standards, etc.) or to also claim environmental benefits under such other programs so long as the renewable electricity generator's participation does not conflict with the fundamental requirement that qualifying renewable fuel be used only once and for the statutorily mandated purpose. This is in keeping with our treatment of liquid and gaseous fuels in the RFS program—we allow parties to ''stack'' multiple credits for these fuels, so long as doing so is consistent with ensuring with the single use of a volume of renewable fuel for transportation within the covered area.

Similarly, we are not proposing to limit the ability of renewable electricity generators to stack credits for renewable electricity generation, when and where appropriate. For instance, a renewable electricity generator located in a state with a renewable portfolio standard (RPS) that allows for renewable electricity credits (RECs) for biogas generated electricity may continue to generate RECs in addition to entering into RIN generation agreements so long as the applicable state's RPS does not place prohibitions on this activity. Furthermore, this proposal does not intend to disrupt or otherwise preclude the use of any other federal, state, or foreign government incentives for certain types of electricity generation in the form of either investment tax credits or production tax credits for which a renewable electricity generator may be eligible. However, in order to ensure that the statutory requirements of the RFS program are met, the qualifying renewable electricity may only be designated for a single use: transportation fuel within the conterminous United States. We believe that this proposed approach is necessary to ensure the integrity of the RFS program and to ensure that the environmental benefits associated with a given quantity of qualifying renewable electricity are not assumed to accrue more than once under the RFS program. We request comment on this proposed approach for the interaction of the eRIN program with other environmental credit programs.

h. Conditions on Electrical Generation Feedstocks

In order to ensure that the renewable electricity for which OEMs contract under RIN generation agreements is actually from electricity generated from renewable biomass, we are proposing that renewable electricity generators that generate electricity onsite from raw biogas may only generate renewable electricity for eRIN generation if 100 percent of the feedstock they use to generate electricity is qualifying biogas during any given month.

We are proposing this limitation because raw biogas can have significantly different conversation rates to electricity than fossil-based natural gas. Furthermore, these conversion rates can vary significantly due to the configuration and operating conditions of the EGUs. We acknowledge that in some instances a renewable electricity generator that uses raw biogas as a feedstock may wish to generate

electricity using a variety of feedstocks. However, in order to ensure that RINs are only generated for renewable electricity produced from qualifying biogas and to minimize program complexity, we believe it is most straightforward to only allow for RIN generation for renewable electricity generation when 100 percent of the feedstock is qualifying biogas. Were we to allow for the co-generation of electricity from qualifying biogas and non-qualifying feedstocks, we would have to impose additional regulatory requirements on the renewable electricity generator to ensure that only the portion of the electricity generation that came from qualifying biogas generates eRINs. These additional regulatory requirements would likely include additional information submitted at registration to determine the types of feedstocks used, the rates that these feeds are converted to electricity, and a detailed description of how the renewable electricity generator would determine the portion of electricity attributable to qualifying biogas. We would also likely need to require additional ongoing reporting and recordkeeping requirements to ensure that the amount of renewable electricity generated from qualifying biogas is accurate as well as require participation in the RFS QAP program to verify it. We believe these additional regulatory requirements would significantly increase the complexity of the program, which would significantly increase the amount of time and burden needed for renewable electricity generators to participate in the program, and EPA to implement and oversee the program.[250]

We also do not believe this proposed restriction would impose much burden on most of the renewable electricity generation facilities that use biogas as a feedstock. We expect these facilities to be located away from the commercial natural gas pipeline system and as such these facilities tend to operate using 100 percent qualifying biogas during typical operation. These facilities would only tend to operate on non-qualifying biogas during startup operations which is a small portion of the time.

Nevertheless, we seek comment on methods to determine the fraction of qualifying biogas used when non-qualifying biogas feeds are co-processed or whether there are ways to minimize the affected amount of renewable electricity.

We are not proposing to limit the co-processing of RNG with fossil-based natural gas because determining the amount of renewable electricity in this circumstance is straightforward. The renewable electricity generator combusting the two feedstocks would know the portion of the total fuel that is RNG based on the quantity of RNG it has purchased with attached RINs. Thus, in cases where RNG is co-processed with fossil-based natural gas, due to the fungibility of these two feedstocks, the amount of renewable electricity generated is simply the fraction of the feedstock that is RNG multiplied by the amount of electricity generated by the renewable electricity generator over a period of time. For purposes of this proposal, the period of time would be on a monthly basis.

i. Biogas Producer Responsibilities

Under our proposal, biogas producers would need to register their biogas production facilities (*i.e.,* landfills or digesters) with EPA, submit periodic reports to EPA for the qualifying biogas they produce, keep records that demonstrate that they produced qualifying biogas, generate and transfer PTDs for biogas transfers, and undergo an annual attest audit. We have used similar provisions for biointermediate and renewable fuel producers who also convert renewable biomass into products that are either renewable fuels or used to produce renewable fuels. We discuss these proposed requirements in more detail in Section VIII.J–Q.

To minimize program complexity and avoid the double-counting of biogas, we are also proposing provisions to govern how biogas producers supply biogas to renewable electricity generators. Under this proposal, biogas producers supplying biogas via a closed system to renewable electricity generators would be limited to supplying a single renewable electricity generator participating in the RFS program. We understand that in real-world applications there may often not be a perfect match between biogas production capacity and the quantity of biogas which can be consumed for electricity generation. In such instances, we want to allow the biogas producers to flare the excess gas or find an alternative productive use. However, in order to minimize program complexity and to safeguard against potential double counting, limiting the biogas producer to supplying only a single renewable electricity generator serves this goal by not allowing the opportunity for double-counting in the first place. We seek comment on the proposal to place limitations on biogas producers that supply biogas to onsite electricity generation.

In the case of biogas supplied for RNG that is later turned into renewable electricity at an offsite renewable electricity generation facility, this biogas and RNG would be covered under the proposed RNG provisions discussed in Section IX.I. Participation in the biogas-to-RNG program, as we have proposed to revise it, will ensure that RNG that is used to generate renewable electricity is produced from renewable biomass and that any RINs generated for the production of RNG are properly retired upon use of the RNG to generate electricity.

j. Third Parties

We use the term ''third parties'' to informally categorize those entities that might participate in a regulatory program but who are not directly regulated (*e.g.,* they are not required to keep records or register with EPA). Third parties currently play a role in the RFS program for all types of renewable fuel in the program. For example, several third parties participate in the RFS in the CNG/LNG space. In that context, many small parties are directly involved in the production, distribution, and use of biogas, RNG, and CNG/LNG. Under our current regulations, there is no one single designated RIN generator—multiple parties are able to register as a RIN generator—and third parties play a role in coordinating the various parties to ensure EPA's regulatory requirements are satisfied and, in many cases, act as a RIN generator themselves. (We note that we are proposing changes to the CNG/LNG regulations under RFS; see Section IX.I for details).

By contrast, for our proposed eRIN program, the proposed regulations state that only a manufacturer of light-duty cars and trucks (*i.e.,* the OEMs) may generate RINs. As discussed in Section VIII.F.2, the proposed program also only designates—directly regulates—three types of entities: biogas producers, renewable electricity generators, and OEMs. Under this proposal, we are not designating third parties, *i.e.,* parties that do not directly participate in the production of biogas, RNG, or renewable electricity or the use of renewable electricity as transportation fuel, as a regulated party with responsibilities associated with eRIN generation. An example of a third party that might participate in the eRIN program is an

[250] This proposed provision would not apply to renewable electricity generated offsite from RNG because we believe that determining the amount of renewable electricity generated from contracted RNG is much more straightforward. Because RNG is indistinguishable from fossil-based natural gas (*i.e.,* would be converted to electricity at the same rates in the same facility), the amount of renewable electricity generated is simply the proportion of feed that was RNG multiplied by the volume of electricity generated by the facility.

entity that assists other parties (*e.g.,* an OEM) with securing contracts for renewable electricity generation.

Based on our experience with CNG/LNG, and from stakeholders' experience in California's LCFS program, we recognize that third parties would likely serve a useful role in supporting regulated parties in brokering and trading biogas, RNG, renewable electricity, and the associated RIN generation agreements under the proposed eRIN program. We also believe that biogas producers, renewable electricity generators, and OEMs would likely contract with third parties to help them comply with the proposed regulatory requirements by preparing and submitting registration requests and periodic reports. However, consistent with the discussion in Section VIII.F.2, we believe that the direct participation of each of the three key parties is necessary in order to ensure that renewable electricity is produced from qualifying biogas and used as transportation fuel in a manner that EPA could reasonably implement and oversee. For example, we think it is important that the OEM remains the responsible party to generate the eRIN, even if the OEM contracts with a third party to do much or all of the work associated with securing contracts for renewable electricity.

Allowing a third party to assume liability for one or more of these key parties would add an additional complication and removes the necessary information, whether it be on renewable biomass, qualifying biogas, renewable electricity, or transportation use, from direct EPA oversight. Further, we believe that our proposed approach best balances our design considerations to regulate only the parties that participate directly in the eRIN generation/disposition chain and leave it to the market to determine how best to engage the services of third parties.

Although we are not proposing a direct regulatory role for third parties in our eRIN program, we seek comment on whether and how they could play such a role. We also seek comment on other ways in which third parties may participate in the proposed program.

6. Data Collection for Program Verification and Future Enhancement

Our proposed eRIN program contains RIN generation equations which use electric vehicle fleet size and disposition data from the OEMs along with prescribed factors for the average EV behavior across the fleet population. The set of prescribed factors proposed in this package would allow for RIN generation at the onset of the eRIN program. However, the EV fleet is continuing to evolve, and we would expect these prescribed factors to evolve with them. In order to improve the precision and accuracy of eRIN generation as the fleet changes over time, we are proposing that OEMs submit data on vehicle efficiency, EV use, and charging efficiency by vehicle make and model for all the electrified vehicle models in service.[251] We discuss each of these in more detail below. This process of updating to reflect the latest information would ensure that eRIN generation calculations remain accurate while still enabling the streamlined, efficient program described above in Section VIII.F.5.a. These data could also enable us to update the transportation fuel consumption formulas in future rulemaking actions to better match the characteristics of the in-use EV fleet as it changes over time, allowing for more accurate and precise eRIN generation and differentiation among OEM fleets. For example, it could enable additional differentiation within the BEV and PHEV categories.

a. Vehicle Efficiency

For the in-use efficiency of EV factor (represented as the fuel economy term) in the formula in the regulations as discussed in Section VIII.F.5 above, we used average values that were adopted from EPA certification testing as this was the best data available. Certification testing data captures the differences between vehicles over the typical operating conditions and therefore should provide a reasonable estimate. Nevertheless, certification testing data may not fully capture the full range of operation of EVs that may ultimately be important to accurately quantify the efficiency of all EVs (*e.g.,* cold temperature conditions in the winter). Consequently, it would be better if we could base this term on actual in-use operation data of EVs, and as such we are proposing that the OEMs provide us with in-use vehicle efficiency (kWh/mi) by vehicle make and model for all the electrified vehicle models in service.

b. Electrified Vehicle Use

The second key data area which we are proposing to collect from OEMs participating in the eRIN program relates to the frequency of EV use. In DRIA Chapter 6.1.4, we discuss the use of vehicle miles traveled on electricity (eVMT) as part of the method by which we calculate the amount of electricity used as transportation fuel. In that discussion we reference and discuss the most recent available data on eVMT for both BEVs and PHEVs. While we believe that the currently available eVMT estimates are reasonable, they are also drawn from a limited data set. Furthermore, in the rapidly evolving EV market segment, consumer driving behaviors that would impact eVMT are also rapidly evolving. Consequently, it is important that we have a means of accurately capturing and updating our eVMT term in the formulas based on the in-use driving behaviors of typical BEV or PHEV owners. To address this need, we are proposing to collect eVMT data or recorded charging information by make and model from OEMs participating in the eRIN program. These data would both help verify the proposed RIN generation equations as well as provide a basis for ongoing program improvement. We appreciate that collecting eVMT information for BEVs is comparatively straightforward (simply annual VMT because all miles traveled are on electric power) relative to PHEVs which switch between powertrain modes depending upon power demands and battery state of charge. Consequently, because of the difficulties in measuring eVMT for PHEVs, we are proposing to allow the submission of either eVMT or recorded charging information by vehicle make and model. We request comment on feasibility and appropriateness of this data submittal requirement.

c. Charging Efficiency

In our proposed eRIN program, charging efficiency is an important parameter in two instances. In the first instance, charging efficiency is an important term in the formula that determines the quantity of electricity that OEMs must procure from EGUs in order to cover the transportation fuel demand of their fleets. Charging efficiency is simply a measure of the fraction of electricity lost to parasitic loads (heat, etc.) during the charging of the vehicle battery. We take account of charging efficiency to capture inefficiencies in the energy transfer processes and to ensure that the full amount of electricity used by electric vehicles is covered by qualifying renewable electricity.[252] The second instance of charging efficiency is in the calculation of the revised equivalence

[251] Exceptions to this requirement may be made in instances where the model is a legacy production and not equipped with onboard telematics necessary for data collection.

[252] This is a unique issue that must be taken into consideration for electricity in order to represent the proper amount of fuel used as transportation fuel. For other renewable fuels, the fueling efficiency of a vehicle is essentially 100 percent. The amount of fuel dispensed is the amount of fuel stored on the vehicle.

value for electricity in the RFS program, discussed in Section VIII.I. In both instances, we are proposing a value for vehicle charging efficiency of 85 percent based on the range of estimates in the literature as discussed in draft RIA Chapter 6.1.4.

We believe 85 percent is representative of the current typical charging situation as most charging currently occurs on private, domestic charging equipment which is almost universally either Level I or II Electric Vehicle Servicing Equipment (EVSE). However, charging efficiency can vary widely depending upon battery state of charge, ambient temperature, and the charging rate. A specific area of concern for which relatively little charging efficiency data is available is Direct Current (DC) fast chargers. Consequently, 85 percent may fail to remain representative if a substantial transition to DC fast charging occurs in the coming years. Furthermore, very few studies have been conducted on the effect of temperature on vehicle charging efficiency, and we hope that more data becomes available as EVs proliferate into colder climates to ensure that our charging efficiency term adequately captures the full range of EV charging. Given the importance of the EV charging efficiency in the eRIN calculation, we are proposing that manufacturers provide us with in-use data on the charging efficiency of their fleet by make and model on the various types of vehicle chargers and under various temperature and battery state of charge conditions.

7. Data Collection for Renewable Electricity Generators, RNG Producers, and Biogas Producers Emissions Verification

In order to establish renewable fuel volumes in the RFS program for renewable electricity that appropriately take into consideration all the statutory factors pursuant to CAA 211(o)(2)(B)(ii), it is necessary that information regarding the environmental performance of the participating renewable electricity generators, RNG producers, and biogas producers be made available for analysis and consideration. The statutory language governing the Set process for RFS volumes after 2022 directs EPA to consider a wide spectrum of factors including ''the impact of the production and use of renewable fuels on the environment, including on air quality, climate change, conversion of wetlands, ecosystems, wildfire habitat, water, quality, and water supply.'' [253] Based upon our evaluation of the available facility data, the vast majority of renewable electricity generators eligible for participation in the RFS program are below the mandatory reporting threshold for biomass-fueled electricity generation facilities.[254] Consequently, detailed emissions information is not required to be reported to EPA at this time.

In order to better assess the potential environmental impacts of renewable electricity production and use for the purpose of setting volumes, we are proposing that participating renewable electricity generators, RNG producers, and biogas producers submit air emissions and liquid and solid effluent production data at registration. The specific types of information we would require from biogas producers, RNG producers, and renewable electricity generators are laid out in proposed 40 CFR 80.150 (''Reporting''). Requiring air emissions and liquid and solid effluent production reporting as a condition of program participation for renewable electricity generators will enable EPA to more fully evaluate the environmental impacts of eRIN volumes moving forward. We request comment on the reporting of air emission and liquid and solid effluent information as a condition of program participation for renewable electricity generators, RNG producers, and biogas producers.

G. How the Proposed Program Structure Meets the Goals

As discussed in Section VIII.H, EPA recognizes that there are a number of different approaches we could have taken to designing the structure of an eRIN program. However, as discussed in Sections VIII.E and F, we have chosen to propose a specific approach that we believe best achieves the goals articulated in Sections VIII.C and D. Specifically, the proposed approach would provide a relatively simple to implement but enforceable program that allows for the maximum incentive from the RFS program to grow the use of renewable electricity as transportation fuel while simultaneously enabling compliance with the statutory requirements. We discuss each of these aspects below in more detail.

1. Simplicity and Enforceability

Foundational to our proposed eRIN program's strength and anticipated success is that the structure is simple (at least in relation to the alternatives discussed in Section VIII.H.) yet readily enforceable. This goal is critical given that, as discussed in DRIA Chapter 6.1.7, it is expected to result in a very large revenue stream, and therefore also provide a significant incentive for fraud that could then undermine the key purpose of the RFS program, increasing the use of renewable fuels in transportation.

The proposed approach aligns well with the capabilities of the parties involved in establishing and managing the necessary contractual arrangements. We expect the result of this alignment to be effective program participation at every stage of the eRIN generation/disposition chain, comparatively simpler oversight, and a higher certainty of RIN validity. The proposal 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 renewable feedstock (*i.e.,* biogas) producer, the renewable fuel producer (*i.e.,* renewable electricity generator), and the party that can demonstrate its use for transportation (*i.e.,* the OEM). Each party would have a set of clearly defined roles and responsibilities under the program. However, the majority of the responsibility and liability would be placed on the OEMs as the eRIN generator. By virtue of OEMs being relatively few in number, relatively large in size, having a vested business interest, and being already relatively experienced with our regulatory oversight, we believe that their role as the eRIN generator would help enable effective oversight to ensure the validity of the eRINs that are generated.

Furthermore, the proposal takes a simple, top-down approach to the data needed to generate eRINs, minimizing opportunities for double-counting and fraud, ensuring that quantities of renewable electricity used as transportation fuel are real, and providing confidence that investment for growth in renewable electricity will not be undermined. RINs are generated by the OEMs using only light-duty EV registrations as an input variable into the equation used to quantify renewable electricity use as a transportation fuel. This data is readily available and readily verifiable based on existing public data from the states that register the EVs and through parties that aggregate such data. All other inputs to the calculation are values prescribed in the regulations and would be updated periodically to ensure accuracy over time based on new data collection and reporting requirements. This contrasts with several of the alternative structures which would rely on potentially billions of data records collected from many entities in real time and for which both

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

[254] EIA form 860, Section 6, *https://www.eia.gov/electricity/data/eia860.*

incentive and opportunity would exist for fraudulent behavior. This top-down approach is a comparative advantage of our proposed approach relative to various alternatives discussed in Section VIII.H, as EPA and industry efforts would not need to be expended to implement complex data and audit systems to detect and enforce against potential fraud. Rather, by virtue of program design, we have minimized the potential likelihood of fraud occurring.

Another important benefit of this top-down data approach would be the absence of the need to collect any personal information in order to enable eRINs to be verified. The proposed approach would not rely on any data from individual vehicle operation or location (other than vehicle registration information within the continental U.S.) nor any data from any individual vehicle charging events. The data used for eRIN generation under our proposed approach can readily be checked and verified not only by EPA but other interested stakeholders and would avoid the need to establish systems and processes to ensure that personal information is kept confidential.

In addition to ensuring that renewable electricity is used as transportation fuel, the proposed approach would also ensure that the renewable electricity was produced from renewable biomass under an EPA-approved pathway. We believe that our proposal to leverage the existing regulatory framework governing biogas-to-CNG/LNG pathways, as well as the proposed revisions to those regulations detailed in Section IX.I, would provide assurance that electricity is generated from qualifying biogas or RNG before it could be used to generate eRINs by the OEMs. By building off of and learning from the past implementation of the biogas-to-CNG/LNG pathways, we believe that we can ensure the validity of eRINs.

One critical aspect of our approach is our proposal to allow OEMs to enter into RIN generation agreements with multiple renewable electricity generation facilities, but to limit each renewable electricity generation facility to contracting with a single OEM, as discussed in Section VIII.D.2. This structure for RIN generation agreements would make it much more straightforward for EPA and independent third parties to effectively audit how renewable electricity from qualifying biogas was used as a transportation fuel and would virtually eliminate the possibility that renewable electricity is double-counted. Our experience implementing the existing biogas-to-CNG/LNG provisions has necessitated that we propose a similar limitation on contracting for RNG as discussed in Section IX.I and for biointermediates as recently finalized in the 2020–2022 RFS rulemaking.[255]

In addition to this overall design structure, we believe that the specific regulatory requirements that we are proposing to implement the eRIN program as described in more detail in Sections VIII.J through VIII.S would enable us to ensure, at each step of the process, that the eRINs ultimately generated are valid. For example, the proposed requirement that each of these parties register with EPA in order to participate in the eRIN program would position us to provide direct oversight to ensure that (1) biogas is produced from renewable biomass, (2) renewable electricity is produced from qualifying biogas under an EPA-approved pathway, and (3) OEMs generate eRINs only from a sufficient quantity of renewable electricity produced from qualifying biogas to cover the electricity used by their fleets.

2. Incentivizing Growth in Renewable Fuels

Consistent with our approach to growing renewable fuels and volumes under RFS generally, the proposed eRIN program would maximize the incentive to increase renewable electricity used as transportation fuel, and would furthermore focus on the lowest GHG renewable fuels (*i.e.,* cellulosic biofuel). The eRIN program design decisions we are proposing in this action would, among other things, result in large increases in cellulosic biofuel volumes under the RFS program for 2024 and 2025, as discussed in Section VI.A.

First, the proposed program would readily allow for the inclusion of all renewable electricity used in the entire in-use light-duty EV fleet, both existing vehicles and new sales. By relying on top-down data as discussed in Section VIII.D.2, the proposal would automatically allow every EV registered in a state within the conterminous United States to count toward eRIN generation and would automatically include all electricity consumed in those EVs regardless of where they are charged within the conterminous United States. Our proposed design would avoid excluding any vehicles that do not have the telematic data necessary to support the use of bottom-up data, and any vehicle charging that might be excluded through a geofencing type approach as discussed in Section VIII.I in support of a hybrid structure. Second, the proposal would automatically allow inclusion of all biogas-derived renewable electricity generated domestically or internationally that can be used within the conterminous United States. This would include all existing biogas EGUs and any new ones that are connected to the commercial electric grids serving the conterminous U.S. Our proposal would also allow for inclusion of the gross amount of renewable electricity generated from biogas by the facility, enabling the maximum incentive for the generation of renewable electricity from qualifying biogas.

Third, as discussed above, the proposed structure would minimize opportunities for double-counting and fraud, ensuring that volumes are real and providing confidence that investment for growth in volumes would not be undermined. Fourth, the simple design structure that leverages our existing structure for RNG would allow for limited additional implementation burden which in turn would enable the production of renewable electricity to begin as early as possible, on January 1, 2024. In contrast to other, more novel and/or data intensive alternatives discussed in Section VIII.H, comparatively little time would be needed under the proposed approach for EPA and industry to put in place the necessary data systems, staffing, and/or contracts necessary to begin eRIN generation. Finally, and importantly, we believe the proposal to place both renewable electricity generators and light-duty electric vehicle OEMs in a position to directly benefit from the revenue from eRIN would address three key hurdles to the growth of renewable electricity used as a transportation fuel under the RFS program: the production and capture of biogas, the generation of renewable electricity from qualifying biogas, and the use of that renewable electricity for transportation.

Biogas producers, renewable electricity generators, and OEMs are all integral parties in the eRIN generation/disposition chain, and we anticipate that through the proposed structure a portion of the value of eRINs would flow through private contractual mechanisms to these parties as needed to support the overall growth of renewable fuel in the form of renewable electricity. As the eRIN generators, OEMs would be the parties responsible for demonstrating that renewable electricity is used as transportation fuel, but they would need to contract with renewable electricity generators (which would in turn contract with biogas producers) to demonstrate that the renewable electricity used as transportation fuel to generate the eRINs

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

came from qualifying renewable biomass. We expect that this requirement for the eRIN generator to demonstrate both the ''use as transportation fuel'' and ''from qualifying renewable biomass'' would create a market dynamic wherein a greater portion of the eRIN revenue would flow to whichever parties were most in need at any particular point in time to support expanded volumes of renewable electricity. For example, an OEM may have a fleet capable of consuming 1,000,000 megawatt hours of renewable electricity a year, but if they are only able to enter into RIN generation agreements for 600,000 megawatt hours of renewable electricity, they would only be able to generate RINs for sixty percent of their fleet. In order to generate more eRINs, the OEM would need to ensure that a greater portion of the value of those eRINs makes its way to the renewable electricity generators in order to incent greater electricity generation from qualifying biogas. If there were a constraint on production of qualifying biogas, the renewable electricity generator would need to direct a greater portion of the eRIN value to those biogas producers to incent greater production. Consequently, we believe all parties would have a mutual interest in ensuring the maximum quantity of eRINs are generated annually, and that as a result eRIN revenue would contractually flow to the limiting resource through the free market.

The portion of the eRIN revenue flowing to renewable biogas producers would support eventual growth in the capture and use of additional quantities of biogas. The portion of the eRIN revenue flowing to renewable electricity generators would not only support more investments in such renewable electricity generators, but could also help reduce the cost of renewable electricity to consumers. Finally, the portion of the eRIN revenue retained by OEMs would help lower the cost of EV production and EV purchases by consumers. The vehicle market has always been an extremely competitive market, and with the many new EV offerings by virtually every vehicle manufacturer, including new manufacturers, we expect the EV market to be an extremely competitive market as well. In such a competitive market, OEMs will be forced to pass along revenues received from RINs to consumers in the form of lower EV purchase prices, charging subsidies, and other incentives or lose market share. This in turn would incent EV sales and thereby demand for the use of renewable electricity.

3. Ensuring Statutory Criteria Are Met

The proposed program also provides assurance that the statutory criteria are met: that renewable electricity that is used to satisfy the renewable fuel volumes is both produced from renewable biomass and used as transportation fuel. The fundamental structure of the proposed program, including our decision to focus the proposed program requirements on the biogas producer, renewable electricity generator, and OEM, is designed to make those parties best positioned to demonstrate compliance with the statutory requirements the directly regulated participants.

As discussed above, we believe that our proposal to leverage the regulatory framework for the biogas-to-CNG/LNG pathways would provide assurance that only electricity that is generated from qualifying biogas or RNG could be used to generate eRINs. Where our proposal differs from many of the alternatives is in the demonstration that the renewable electricity was in fact used for transportation purposes. As discussed above, the proposed use of a top-down data approach along with our choice to have the OEM be the eRIN generator ensures that eRINs correspond to renewable electricity that is used for transportation and allows little opportunity for double-counting and fraud, ensuring that RINs are valid and providing confidence that investment for growth in renewable electricity would not be undermined.

Relatedly, while we carefully considered other options as discussed in Section VIII.H, our proposal to designate OEMs as the eRIN generator is consistent with the program design goals in Section VIII.C and meets the criteria laid out in Section VIII.D, including ensuring consistency with the statutory requirements. Clean Air Act Section 211(o)(5)(A) directs EPA to provide for the generation of credits under the RFS program by refiners, blenders, importers, and small refineries, and of biodiesel, but does not limit credit generation to those parties [256] and provides no additional guidance relevant to the generation of RINs. Under the existing RFS2 program for liquid biofuels, we determined that it was reasonable to designate renewable fuel producers as the RIN generator. In the case of renewable electricity used for transportation, we believe it is reasonable to designate the OEMs, who hold one of the two pieces of information necessary to demonstrate that renewable electricity is a qualifying renewable fuel, as the eRIN generator. Furthermore, as discussed in Section VIII.F.3 we believe that having the OEM be the RIN generator, as opposed to the renewable electricity generator, will enhance our ability to track and verify the validity of the renewable electricity. Finally, by having the OEM be the sole entity that is able to generate the eRIN, we would be able to put in place a simple, straightforward program that allows every eRIN to be readily verified as meeting the statutory criteria. Unlike the more data and labor-intensive alternatives considered in Section VIII.H, the proposed approach would not afford any opportunity for double-counting of electricity use.

H. Alternative eRIN Program Structures

Section VIII.F describes our proposed eRIN program structure. We believe this structure would best meet the goals articulated in Section VIII.C, best balance the many program considerations described in Section VIII.D, and support the proposed program applicability outlined in Section VIII.E. At the same time, we acknowledge that the RFS eRIN program could be structured in a variety of different ways, and over the past several years we have heard directly from multiple stakeholders on this topic. Individuals, companies, and trade associations have suggested a wide range of alternative program structures designed to address many of the same program considerations, as well as some additional or different considerations, through other approaches. These alternative program structures vary in many aspects, including: which party is eligible/allowed to generate the eRIN; which parties should be regulated as part of the generation/disposition chain for the eRIN; what types of data are used and required as a basis for generating the eRIN; and how compliance with statutory and regulatory requirements is assured.

In developing this proposal, we have given careful consideration to other potential program structures and the varying approaches that could be taken regarding key design elements. Below we discuss a number of the alternative approaches. For some of these, an assessment of the approach helps shed light on the reasoning for our proposing

[256] The RIN system serves two purposes: as a general compliance mechanism, and as a means of implementing the statutes' credit provisions. EPA also established the RIN system utilizing its authority under CAA Sections 211(o)(2) and 301 to establish a compliance program which could include credit elements that extend beyond the specific elements required in CAA Section 211(o)(5).

the approach included in this action. For others, we seek to highlight some of the policy or implementation advantages we recognize in the alternative approaches. We describe below the main alternative eRIN program structures we considered. We request comment on whether and how any of these alternative structures could better meet the goals we have articulated, including satisfying the applicable statutory requirements and purpose, as well as whether and how they could satisfy the relevant program considerations. We further seek comment on whether we should pursue any of these alternative approaches, rather than our proposed approach, or variations of them.

1. Designating Renewable Electricity Generators as the Sole Entities Eligible To Generate eRINs

The first alternative structure we discuss closely mirrors our proposed approach in Section VIII.F but would change the entity that generates eRINs. This alternative would regulate the same parties as the proposed structure (biogas producers, renewable electricity generators, and OEMs) but would designate the renewable electricity generators as the RIN generators, as opposed to OEMs. While the same three parties would comprise the eRIN generation/disposition chain and still likely share in the revenue generated by the eRIN, the regulatory obligations outlined in the proposed regulations for RIN generation would shift from the OEMs to the renewable electricity generators. Stakeholders who have advocated that EPA adopt this approach argue that renewable electricity generators play a role similar to that of liquid renewable fuel producers that generate RINs for fuels like ethanol under the RFS program. Such stakeholders argue that only a structure that designates the electricity generators as the sole RIN generating entity can ensure that entities responsible for directly increasing supply of renewable electricity are properly incented.

From a program design perspective, we observe at least two significant drawbacks to this approach relative to designating the OEM as the sole entity eligible to generate RINs. The main concern we have with this alternative program structure is that it would be much more difficult to implement, oversee, and enforce than the proposed approach. This is primarily because we would expect a significant increase in the number of RIN generators under this alternative—by approximately a factor of fifty—many of whom would be small entities. Many of the electricity projects which we expect would register for the program would be small businesses or projects owned by municipal governments. These smaller entities may not have the staff, resources, or expertise necessary to comply with the regulatory obligations associated with RIN generation. Relatedly, due to the small size of the facilities, they may lack experience complying with EPA regulations, and with EPA fuels regulations specifically.[257] We anticipate that the number of entities involved in RIN generation coupled with their relative lack of staff, resources, and experience would likely result in inadvertent issues concerning compliance with the applicable regulatory requirements resulting in the generation of invalid RINs.

We also do not believe that the renewable electricity generator would be ideally positioned to demonstrate that renewable electricity was used as transportation fuel, and crafting regulatory provisions to necessary for renewable electricity generators to do so would significantly increase the complexity of the program. As the RIN generator, the electricity generator would be responsible for not only demonstrating that the renewable electricity was made from qualifying biogas but also that the renewable electricity was used for transportation. Such a demonstration is not currently a requirement for most liquid renewable fuel producers under the RFS program given that is reasonable to assume that the dominant use of liquid renewable fuels is for transportation. However, it is a requirement for RIN generation for biogas to renewable CNG/LNG given CNG/LNG's potential use for non-transportation purposes.[258] Similarly, in order to demonstrate that only renewable electricity that was used for transportation generates RINs and that no double counting occurs, the renewable electricity generator would have to ensure that any OEM with which it has entered into a RIN generation agreement properly accounted not just for that generator's renewable electricity generation, but also the renewable electricity of all generators with which it has entered into contractual arrangements. This is because, as discussed in Section VIII.F.5.b, OEMs would have to enter into RIN generation agreements with multiple renewable electricity generators to cover their EV fleet's electricity use. It would be challenging for an electricity generator, particularly a small one, to demonstrate that an OEM has properly accounted for all the electricity generation from their various contracts.

We do, however, believe that we could craft regulatory provisions to position the renewable electricity generator as the RIN generator. These provisions would likely have to impose additional requirements on the timing of RIN generation (*i.e.,* RINs could only be generated after an OEM has allocated electricity to transportation use, then informed each contracted renewable electricity generator of the proportion of each electricity generator's electricity that was used as transportation fuel), require the use of the RFS QAP to ensure that RIN generation occurred correctly across the entire system, and put in place enhanced tracking requirements to ensure that renewable electricity was not double-counted. The complication of these additional regulatory provisions would necessitate more lead time for EPA and industry to implement the program and increase the overall burden of the program that would be needed to provide the same level of compliance assurance as the proposed approach.

The proposed OEM structure avoids these complications by positioning the party best able to demonstrate that renewable electricity was used as transportation fuel as the party that generates the RIN. Under the proposed structure, an OEM would establish RIN generation agreements with many different renewable electricity generators in order to obtain the requisite quantity of renewable electricity to meet its fleet's renewable electricity consumption. Verifying the

[257] Many biogas EGUs are 1–10 MW in scale, and as such likely have little experience with regulatory compliance regimes. Of the 378 facilities listed in the EPA Clean Air Markets Division eGRID database (United States, Congress, Clean Air Markets Division. *eGRID 2019 Data File*), 322 are under 10 MW. Many of these facilities are too small to be subject to even state air permitting programs and therefore may not currently have a need for the type of regulatory compliance resources and expertise that would be needed for eRIN generation.

[258] Under the regulations at 40 CFR 80.1426(f)(17)(i)(B), for renewable fuels other than ethanol, biodiesel, renewable gasoline, or certain types of renewable diesel, in order to generate RINs the renewable fuel producer must demonstrate that the renewable fuel was used as transportation fuel, heating oil, or jet fuel by either: (1) blending the renewable fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil or jet fuel; (2) enter into a written contract for the sale of the renewable fuel which specifies the purchasing party shall blend the fuel into gasoline or distillate fuel for use as transportation fuel, heating oil, or jet fuel; or (3) enter into a written contract for the sale of the renewable fuel, which specifies that the fuel shall be used in its neat form as a transportation fuel, heating oil or jet fuel. Under the current regulations, parties that generate RINs for biogas to renewable CNG/LNG must show that the biogas was used as transportation fuel under 40 CFR 80.1426(f)(10) or (f)(11), as applicable.

validity of these RIN generation agreements and ensuring that there is no double-counting of the biogas electricity generation under the proposed approach is a relatively straightforward matter, as all of a renewable electricity generator's renewable electricity production could only be used by one OEM for eRIN generation. The relatively limited number of parties acting as RIN generators in our proposed approach is a positive with respect to program oversight and compliance because it makes preventing double-counting of renewable electricity a relatively simple and straightforward proposition to implement.

Critically, under the proposed OEM structure, renewable electricity generators would merely have to engage in RIN generation agreements with OEMs in addition to the electricity offtake agreements they already engage in. This level of regulatory responsibility would seem to align better with the electricity generators' capabilities. They would still receive revenue through the contracts with the OEMs, but would not need to invest significantly in eRIN compliance assurance activities.

We request comment on smaller electricity generators' abilities to facilitate RIN generation and whether only a program that positions the electricity generators as the RIN generating entity can accomplish the goal of encouraging growth in the supply of renewable electricity. We further request comment on the extent to which our proposed approach—designating OEMs as the sole entities eligible to generate RINs—would differ in its ability to encourage such growth in renewable electricity, as compared to this alternative.

2. Designating Public Access Charging Stations as the Sole Entities Eligible To Generate eRINs

A second alternative structure would designate public access charging stations for EVs as the sole type of entity that would be eligible to generate eRINs. Under this approach, the consumption-side data for the program, demonstrating that renewable electricity was used as transportation fuel, would come from charging data associated with public access charging stations. As under the proposed OEM structure, the public access charging stations would need to rely on contractual relationships with renewable electricity generators and biogas producers to demonstrate that renewable electricity was generated from qualifying biogas or RNG. Thus, while renewable electricity generators and biogas producers would remain part of the generation/disposition chain for eRINs, this structure would substitute the public access charging station for the OEM.

A primary policy reason to adopt such an approach concerns the question of which barriers to increased growth of renewable electricity used for transportation could be best addressed by an eRIN program. There is a significant body of technical and policy analysis that identifies the need to expand public access EV charging infrastructure in order to support increased electrification of the transportation sector which is in turn then needed to expand the use of renewable electricity under the RFS program.[259] Beyond such studies, EPA has heard directly from stakeholders who assert that a key barrier to widespread electrification of the transportation sector is the need for widely available access to public charging, and that some form of additional economic support is beneficial, or even necessary, in order to support the business model of public access charging stations. Stakeholders acknowledge that this dynamic may change over time, but given where the U.S. stands today in EV charger build-out, they maintain that additional public policy support is warranted. The Biden Administration has already acknowledged and acted on this need; in February 2022, for example, the Departments of Energy and Transportation announced $5 billion to be made available to build out a nationwide EV charging network.[260] Furthermore, in August 2022 the Inflation Reduction Act included tax credits for developing charging station locations, with incentives for chargers built in low-income or rural census tracts.[261]

With respect to EPA's development of new eRIN regulations, some stakeholders have argued that in light of the need to directly support public charging infrastructure expansion, EPA should prioritize the need to ensure that any associated RIN revenue supports charging infrastructure in as direct a fashion as possible. And more specifically, that EPA should consider a structure designating public access charging stations as the sole entities eligible to generate eRINs, or barring that, at least ensuring that they are able to generate eRINs directly as part of hybrid approach (see later descriptions of hybrid approaches). Ensuring that charging stations can register to generate eRINs, stakeholders argue, provides the most direct form of support for expansion of charging infrastructure via the eRIN program. Such parties would be best positioned, they assert, to focus eRIN revenue on charger build-out.

Some stakeholders, in support of this approach, also point to the need for additional financial support to ensure the long-term viability of the business model underlying public charging stations. Some of these stakeholders have conveyed that the combination of electricity capacity payments, along with relatively low charger utilization rates, creates a situation where the cost of charging (particularly fast charging) can exceed the cost of gasoline on an energy equivalent basis. Consequently, these stakeholders believe that without additional financial support, public access charging will not develop at the rate necessary in all parts of the country where it will be required to address EV charging needs and therefore be a barrier to the electrification of the fleet. These stakeholders argue that an eRIN structure that positions public access charging stations as the RIN generator would allow them to reduce direct costs to their customers, thereby reducing the total cost of EV ownership. As an additional result, they argue that directing eRIN revenue to public access charging stations would allow them to expand the geographic reach of their charging networks. This would increase the prevalence and availability of public charging infrastructure and help to relieve range anxiety for owners/potential owners of electrified vehicles.

While there are other funding mechanisms in place and being developed for public access charge stations to support the deployment of EVs nationwide, EPA agrees that designating public access charging stations as the sole type of entity eligible to generate eRINs could provide a relatively direct funding mechanism for EV public charging. We believe this structure could be implemented at a national level, though it may be more complicated than the proposed structure. The relative ease of implementation in this case is tied directly to the data which we would require for eRIN generation. Because charging stations collect information on the quantity of electricity dispensed as a regular business practice, there is a readily available dataset which could be used as the basis for calculating electricity consumption and then RIN

[259] Driving The Market For Plug-In Vehicles: Developing Charging Infrastructure For Consumers, UC Davis, International EV Policy Council, *https://phev.ucdavis.edu/wp-content/uploads/Infrastructure-Policy-Guide-March-2018.pdf.*

[260] *https://www.energy.gov/articles/president-biden-doe-and-dot-announce-5-billion-over-five-years-national-ev-charging.*

[261] H.R. 5376, SEC. 13404.

generation. The availability of such a dataset, which provides a direct measurement of the electricity provided to a vehicle is a key advantage of this approach.

While we acknowledge the benefits of an approach that provides access to such datasets, EPA has some concerns related to data verification and validation. The sheer volume of data (millions, and eventually billions, of individual charging events) means that verification of the data would necessarily need to be done by some combination of third party verifiers and EPA spot audits. This work would require substantial oversight and enforcement resources; this is not necessarily a barrier, but it is at least an important consideration as discussed in Section VIII.D. The volume of charging station data could provide an opportunity for and incentive for fraudulent behavior. We anticipate the value of the eRIN to exceed the cost of electricity by a substantial margin.[262] This circumstance creates an incentive to inefficiently dispense electricity at the charge stations, redirect it for other purposes, or to otherwise participate in wasteful charging practices in order to generate as many RINs as possible. We have yet to determine if a set of protocols could be developed to effectively curtail this potential fraudulent behavior.

Beyond such concerns, perhaps the primary drawback to a structure that exclusively positions public access charging stations as the RIN generator is that it inherently limits the quantity of eRINs which can be generated to the fraction of vehicle charging which occurs at public charge stations. Recent estimates put the fraction of EV charging which occurs at public charge stations around 20 percent.[263] If an eRIN program were designed so that only this portion of charging were eligible to generate eRINs, it would arguably limit the RFS program's ability to encourage increased use of renewable electricity as a transportation fuel.

An additional consideration for the public access charging station only structure centers upon the types of entities that own/operate charging stations. Although the majority of charging stations across the country are owned/operated by large networks that would have the staff, resources, and expertise necessary to comply with the regulatory obligations associated with RIN generation, there are a number of public access charging stations owned by small businesses and municipalities. These smaller entities would face significant challenges to participation in a national eRIN program. A lack of participation by smaller networks or stand-alone stations would, in aggregate, further erode the impact of the eRIN program and potentially would introduce an incentive structure which only encourages participation from large-scale networks.

A final consideration for the public access charging station only structure centers upon the mostly short- to medium-term need to build out the public charging infrastructure with the longer-term nature of the RFS program and the inability to direct where the buildout occurs. Unlike other federal, state, and local financial incentives, which can and are being put in place to target consumer public charging needs in particular locations and only for the duration where the need still exists, the financial incentive from the eRIN would not be able to do so. Rural and other charge locations with low use but which are important for consumer confidence when making an EV purchase decision would remain poor business in comparison to other locations with higher EV use. The eRIN would also continue to provide an incentive for the life of the program regardless of the need. Arguably, once the needed public access charging infrastructure was in place it could result in incentivizing less efficient use of resources to further support public access charging at the expense of private charging. While public access charge stations could shift the revenue from the eRIN toward lowering the price of electricity at public access charge stations, we believe that our proposed structure addresses two other, critical limitations to increasing the use of renewable electricity as transportation fuel—the relatively high cost of EVs and the need for greater renewable electricity generation—and thus better meets the goals discussed in Section VIII.C. Additionally, other mechanisms exist that can and will be employed to support EV public access charging infrastructure.[264] Nevertheless, access to public charging is currently a significant factor in expanding the electrification of the transportation sector, and therefore providing revenues from eRINs could be an important part of expanding that infrastructure. We therefore seek comment on potential structures that could support EV public access charging infrastructure, including hybrid structures as discussed below.

3. OEM-Centered Approach Using Telematics Data

A third alternative does not structurally differ from the proposed structure, but would use telematics[265] data, rather than the proposed top-down aggregate approach, in order to demonstrate ''use as transportation fuel''. In such an approach, charging data from onboard vehicle telematics would be utilized rather than a top-down methodology to determine the quantity of renewable electricity used as transportation fuel. This source of data would be the most precise—recording the actual electricity that went into the vehicle's battery as reflected in its state of charge. Such an approach would arguably help eliminate incentives for inefficient and/or fraudulent behaviors associated with vehicle charging and would be equally applicable to public and private charging. It would create an auditable stream of specific data that would potentially help in compliance and oversight efforts, and would avoid some of the uncertainty associated with top-down estimation approaches.

To implement such a system, EPA would have to establish mechanisms to collect, aggregate, and report the vehicle telematics data on a regular interval to serve as the basis for eRIN generation and allow for manageable oversight.[266] The development of a mechanism to collect, aggregate, and report potentially billions of charging events would take a significant amount of time and would need to be updated frequently to adapt to changes in vehicle telematics information over time. Adopting an approach that relied on vehicle telematics as a basis for RIN generation could significantly delay when we could allow for eRIN generation as we take time to develop a mechanism to collect, aggregate, and report vehicle telematic information. Furthermore,

[262] With the revised equivalence value and D3 RIN prices of approximately $3/RIN the value of renewable electricity in the eRIN program would be on the order of $450/MWh.

[263] ''Charging at Home—Department of Energy.'' Available: *https://www.energy.gov/eere/electricvehicles/charging-home.*

[264] EPA has observed an increase in the prevalence of CNG/LNG refueling infrastructure despite the RINs from CNG/LNG typically not being generated by the refueling stations themselves. The majority of value from CNG/LNG RINs has been directed towards entities producing RNG and towards reducing the purchase price of vehicles capable of utilizing CNG/LNG. The resultant increased demand and attractively priced, RIN subsidized fuel, have served to create market conditions where investment in refueling infrastructure is warranted.

[265] Telematics broadly refers to onboard vehicle data collection systems (GPS, onboard diagnostic systems).

[266] RINs are often transacted in the RFS program in block of millions and even hundreds of millions of RINs, so some means of acquiring the data and aggregating it into manageable blocks would be required.

while all future vehicles could be designed to report the necessary information into some new electronic system, this would not be the case for much of the legacy fleet, whose electricity consumption would dominate at the start of the program. Additionally, the eRIN program may expand beyond light-duty vehicles into other transportation sectors in the future where telematics may or may not be a viable option. Although we are proposing to only allow for light-duty vehicles to participate in the eRIN program at this time, a lack of ubiquity and standardization regarding vehicle telematics curtailed our ability to leverage this data source at this time. We request comment on the potential advantages and drawbacks of leveraging vehicle telematic data across multiple vehicle segments to construct or improve the eRIN program. We further request comment on how we could reduce or mitigate burdens associated with program oversight and compliance (*e.g.,* use of auditors) were EPA to eventually pursue an approach that relied on telematics data. Finally, we request comment from stakeholders who have participated in programs like California's LCFS, where highly detailed data is required, and what lessons can be applied in the development of EPA's eRIN program.

4. Hybrid Structures

Consistent with the Congressional intent of the program, one of the main program design considerations we sought to address with our proposed structure was that the program be able to capture the largest share of renewable electricity use in transportation possible. This translates into the maximum number of RINs being generated from the eRIN program and ultimately the largest incentive for the growth of renewable electricity for transportation purposes. We believe that our proposed eRIN structure, which designates OEMs as the sole RIN generators, would accomplish this. However, we have also explored whether it is possible to maximize eRIN generation while also directing a portion of the program incentives to support public access charging stations more directly than our proposed approach might do.

As EPA began development of new regulations on eRINs, several stakeholders argued that EPA should establish a regulatory structure in which both OEMs and public access charging stations would be eligible to generate eRINs. Some pointed to California's LCFS as an example of where such a program works today. In this notice, we refer to program structures where multiple parties are eligible to able to act as eRIN generators as ''hybrid'' approaches.'' While we have considered a wide range of potential hybrid structures, we discuss the primary ones in this section. We request comment on the benefits and drawbacks of the various hybrid structures presented below, whether EPA should adopt one of these hybrid structures, and if so how to address the issues and challenges they would raise.

a. Designating Both OEMs and Public Charge Stations as Entities Eligible To Generate eRINs

The first type of hybrid structure we considered is one in which both OEMs and public access charge stations would be eligible to act as eRIN generators. Both entities would be required to secure contracts with renewable electricity generators to demonstrate procurement of the necessary renewable electricity from qualifying biogas and they would have to use unique, *i.e.,* non-overlapping, data to demonstrate transportation use in order to avoid double counting.

i. California LCFS-Type Structure

A number of stakeholders have pointed to how electricity credits are managed under California's Low Carbon Fuel Standard (LCFS) Program as a template for how EPA could implement a hybrid national program that includes both OEMs and public access charge stations. While it is not possible for EPA to directly adopt the California structure for eRINs under the RFS program, we gave careful consideration to whether we could adopt a data collection and tracking structure similar to that used in California that would allow both OEMs and public access charge stations to generate RINs.

The first ''layer'' of LCFS credits for electrified vehicles is generated by the electric utility servicing the area where those vehicles are registered. The LCFS program then layers on top of this a system of providing additional LCFS credits for low-GHG electricity used in transportation to both vehicle manufacturers and charging stations, based on vehicle telematic charging data and public access charging data.[267] To avoid double counting in the system—for example, to avoid a situation where an LCFS credit for one charging event is simultaneously created for both an OEM and a public charging company—the LCFS program relies on a ''geofencing'' system. Through technology-based geofencing, the locations of public charging stations are known with a reliable degree of precision, allowing data for associated charging events to be segregated from, for example, home-based charging. Doing so allows LCFS credits to be generated by different entities: charging station owners receive LCFS credit for charging station events, for example, and an OEM might receive LCFS credit for certain types of home charging (provided other program requirements are all met). In so doing, the program is designed to enable direct financial support, via LCFS credits, to the owners of charge stations as well as to other entities like OEMs.

Stakeholders have suggested that a similar approach could be used as part of an eRIN program to allow both OEMs and public charge stations to generate eRINs while providing the required demonstration that the renewable electricity was not double counted and was, in fact, used for transportation purposes.[268]

Under the California program, charging stations collect charging session IDs, charging session start and end times, total time spent charging, total energy dispensed, charging station and plug IDs, plug type, maximum power output, city, state, zip code, venue type, and charging station activation date. All this data must then be synthesized and matched with vehicle telematic data from the charging vehicle, including the Vehicle Identification Number (VIN), the locational data of the vehicle, and the similarly recorded total time spent charging, total energy dispensed, and other charging event data. The charge station and vehicle telematic data must be matched against each other to ensure that only unique events are counted, and charging stations must be geofenced to differentiate between residential and non-residential charging stations. California structured this part of the program so that charging stations could earn credits for charging occurring at their facilities (through the use of electric vehicle charge station data as discussed above) and another entity (typically OEMs) could generate credits for charging (through the use of vehicle telematics data) that occurred away from charging facilities. Though acknowledging the data-heavy requirements and complexity of such a

[267] See Section VIII.H.5.a.i for further details on these data requirements of the CARB LCFS program.

[268] Under the California LCFS program the OEMs and charge stations then procure and retire RECs in order to demonstrate that the electricity was renewable. As discussed in Section VIII.H.2., the RFS program cannot rely on RECs, so some means akin to our proposal would be required for this aspect of such a hybrid structure.

system, particularly as it expanded to more and more homes and businesses nationwide, a number of the stakeholders that EPA met with pointed to the LCFS system as a model that EPA could adopt for a nationwide eRIN program.

In assessing whether a similar model could be adopted for RFS programmatic purposes, a central concern is one of scale: while the LCFS approach may work well at the state level, EPA has concerns about whether it would be appropriate and possible to implement at a national level, given the resources available to EPA and the burden it would place on the many regulated entities. For example, the process of tabulating and crediting charging events under the RFS program would require that each individual charging event be recorded and then audited by a third party prior to generating credits. As the national light-duty vehicle fleet begins to be comprised of a larger share of electrified vehicles we will likely have tens of millions of vehicles charging hundreds of times each year. This would result in billions of individual charging events that would need to be reviewed for accuracy and compliance each year. This would be in addition to oversight of the many contracts between OEMs, charging stations, and EGUs to demonstrate the electricity was produced from renewable biogas.

Moreover, given the magnitude of the eRIN value, there would be considerable financial incentive for parties to find ways within the system to improperly generate eRINs. Consequently, we do not believe that such an approach is currently viable and are proposing an approach to the eRIN program that would be both more streamlined and less data-heavy as discussed in Section VIII.F. The stakeholders that supported this approach generally did not offer particular implementation solutions to such a complex data gathering requirement other than to suggest that EPA could use its resources to manage it, use computer algorithms to screen for potentially abnormal data, and rely on independent third parties to carry out much of the work involved. While we can and do incorporate independent third parties into the design of our program as discussed in Section VIII.F.5.j, leveraging third parties to, *e.g.,* provide quality assurance, this does not relieve EPA of the obligation of promulgating the detailed regulatory framework, establishing the data systems and oversight mechanisms, maintaining the necessary infrastructure, and directly conducting any enforcement necessary to implement an eRIN program. We request comment on specific approaches EPA could use to mitigate resource and complexity concerns associated with this type of programmatic structure.

Additionally, we have also heard from a number of stakeholders currently participating in the LCFS program that have raised concerns about how the program may translate into the future. Specifically, concerns have been voiced regarding the geofenced set-asides for charging stations and how these may interfere with domestic charging, particularly in dense urban areas.[269] These stakeholder concerns contribute to our belief that it would be necessary to implement a much simpler system, were we to adopt a hybrid structure where both OEMs and public charge stations were allowed to function as RIN generators.

Finally, given the complexity of this approach to implementing eRINs, were we to attempt to put it in place, it would likely be difficult to implement by January 1, 2024. Out of a desire to implement the eRIN program as soon as practicable in order to increase the penetration of renewable electricity as a transportation fuel in the near term, we deemed it advantageous to put in place a structure that could be implemented more expeditiously. Given the concerns outlined, we request comment on the benefit of EPA adopting a data-heavy hybrid approach for the eRIN program given the added complexity and potential delayed implementation of the eRIN program. In particular, we seek comment on how and why such an approach could be scaled to the national level.

Some stakeholders have suggested that EPA create an eRIN program that would somehow incorporate broader policy tools or authorities that exist under the California LCFS. A number of fundamental differences exist between the LCFS and RFS programs, however, and those differences mean there will be some policy or implementation options available under one program that might not be available under the other. A key fundamental difference, for example, is that the definition of renewable fuel under CAA section 211(o)(1)(J) requires that it be produced from renewable biomass as defined in 211(o)(1)(I). Thus, only electricity that is produced from qualifying renewable biomass is eligible to generate eRINs under the RFS program. By contrast, under the LCFS program qualifying electricity can be produced from a broader range of energy sources, including wind, solar, and hydroelectric. The scope of what qualifies as renewable electricity for the LCFS credits is considerably broader than what can qualify for eRINs under current CAA authority.

A second fundamental difference between EPA's RFS program and California's LCFS program concerns the ability to direct how parties receiving revenue (*e.g.,* from LCFS credits) must be use those funds. Under the LCFS, utilities are required to use LCFS credit to ''benefit current or future'' EV owners, for example through rebate programs or point-of-sale incentives (*e.g.,* California's Clean Fuel Reward).[270] [271] Some stakeholders have suggested that we should include provisions in our eRIN program that would allow or require EPA to similarly direct revenue towards specific uses. For example, some stakeholders have suggested that EPA establish a program that somehow requires eRIN revenue be used on to lower the purchase price of an EV or alternatively to increase the availability of public charging. The Clean Air Act, however, does not provide us with explicit authority, and we do not interpret the Clean Air Act's silence in this case as allowing us to direct where eRIN revenue is used. We request comment on this interpretation.

Under our proposed approach, the OEM would generate the RIN, and the actors in the RIN generation/disposition chain would determine how RIN revenue would ultimately be allocated. The market, via contractual negotiations among actors in the chain, would dictate, for example, how much of the RIN revenue the OEMs will need to share with the renewable electricity producer and in turn how much of the revenue will need to be shared with the biogas producer. We anticipate that the degree of competition between OEMs on the pricing of EVs will dictate in large part how much of the eRIN value they receive is passed on to consumers in the form of lower purchase prices for new vehicles or subsidized services (*e.g.,* charging). Were we, in the alternative, to put in place an eRIN program that provided eRIN revenue to public access

[269] Non-residential charging stations have an assumed minimum geofencing radius of 220 meters, while residential chargers may use a maximum geofencing radius of 110 meters. These radii are conservative estimates put forth by the California Air Resources Board to account for blocked or reflected satellite signals. This allows matched telematics data to be verified to ensure no double counting. Low Carbon Fuel Standard (LCFS) Guidance 19–03, Reporting for Incremental Credits for Residential Charging, *https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-03.pdf.*

[270] *https://cleanfuelreward.com.*

[271] *https://ww2.arb.ca.gov/resources/documents/lcfs-utility-rebate-programs.*

[272] ''A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects,'' available in the docket.

charge stations, the degree to which that revenue would be passed on to consumers in the form of lower prices would similarly be a function of the degree to which there was competition in the marketplace between charge station networks. In today's marketplace there is widespread competition between fuel stations for gasoline and diesel fuel with many stations typically in close proximity to one another vying for consumer demand. However, significant competition among public charge stations is unlikely until the market matures. We have seen this dynamic elsewhere in retail fueling: in the still-small marketplace of E85 stations, for example, we have not found pricing to be driven by competition such that the full value of the RIN is passed along to consumers in the form of lower fuel prices.[272]

ii. OEM Structure With a Charge Station Carveout

Given the complexities of trying to implement a California type structure, we looked into ways that it might be possible to streamline it to the extent possible. In this hybrid iteration, the OEMs would use the same data outlined in our proposed structure in Section VIII.F to establish the maximum amount of transportation fuel for which their fleet could potentially demonstrate RINs. The charge stations would separately use some form of the charge event information collected as a regular course of business such as that described in Section VIII.H.2 above. Some form of adjustment would then have to be made to subtract the charge events that occurred at charge stations from the overall transportation fuel use calculated by the OEMs to ensure that no double counting of electricity used for transportation occurs. Known issues with this post-hoc reconciliation of data include: ensuring that make and model information is retained by the charge stations so that the proper subtraction can be made from an individual OEM's fleet, creating a workable temporal reconciliation process for the charge events so that RIN generation can be facilitated in a timely manner, and developing a methodology for predicting the rate of public charging such that disruptive over/under RIN generation would not occur on behalf of the OEMs. We request comment on the approach of OEMs as RIN generator with a carveout for charge stations generally, as well as on potential ways to address these challenges to this approach.

There is also an issue regarding double-counting concerns which would exist in such a hybrid structure. In Section VIII.F.2 and H.1 we discussed the benefits of a many-to-one relationship for renewable electricity generators and OEMs, which would be abrogated by positioning the EGUs as the RIN generators rather than the OEMs. This is because a majority of renewable electricity generators are much smaller in their electrical generation capacity than the demanded quantity of electricity from an entire OEMs fleet. A similar asymmetry exists between renewable electricity generators and charge stations. Although it is true that a charge station network may well have enough electricity demand to require contracting with multiple renewable electricity generators, there will be many independently owned and operated public charge stations which would only require a fraction of the electricity production of a single renewable electricity generator in order to meet their charging demand. This would greatly increase the quantity of contracts needed to connect renewable electricity to transportation use; with the higher number of contracts comes an increased probability of overlapping claims on the same quantity of electricity and thus an increased probably of double counting. Furthermore, as discussed in Section VIII.H.2, the program would have substantially more RIN generating parties that would need to register than in our proposed structure. As we have noted previously, many of these charge stations are expected to be small entities that may not have the resources or expertise required to satisfy all the compliance and oversight obligations to participate in the RFS program as RIN generators.

b. Hybrid With Renewable Electricity Generators as RIN Generator

The second hybrid structure to which we gave serious consideration would position the renewable electricity generators as the eRIN generators but would allow both charge stations and OEMs to participate in the program by demonstrating the use of electricity as transportation fuel. Under this structure, the renewable electricity generators would generate eRINs for the specific amount of renewable electricity that is generated and loaded onto the commercial electric grid serving the conterminous U.S. A party, *e.g.,* an OEM or public charging station owner/operator, would separate those eRINs upon demonstrating that the renewable electricity was used as transportation fuel. This approach has the advantage of using the eRIN assigned in EMTS as an additional means of tracking the renewable electricity from generation to disposition. Additionally, because the assigned RIN could only be separated once, this could virtually eliminate the opportunity to double-counting of the renewable electricity. We would expect that the OEM or public charging station would use information similar to that required for RIN generation under the proposed approach, the contemplated public charging station structure discussed in Section VIII.H.4, or hybrid approach discussed in Section VIII.H.5.a.ii. The main difference in this approach would be that the renewable electricity generator could generate and assign the eRIN and would leverage the assigned RIN in EMTS to track how the volume of renewable electricity was used as transportation fuel. This program structure would be similar to the revised structure we are proposing for the generation, assignment, and separation of RINs for CNG/LNG produced from biogas. We discuss in more detail the approach proposed for RNG under the proposed biogas regulatory reform provisions in Section IX.I.

Despite the improvements in program oversite that this hybrid structure would provide, it still has many unresolved issues and would essentially have the same challenges discussed in Section VIII.H.2 with respect to public access charging and the same challenges associated with sequencing RIN generation (separation under this approach) discussed in Section VIII.H.5.a.ii. The main challenge is that this would significantly increase the burden on the core party least able to take on that responsibility, *i.e.,* the many small renewable electricity generators that would serve as eRIN generators. This could significantly complicate or delay the setting up of the eRIN program. This could also result in a significant number of renewable electricity generators not participating in the program which could reduce the number of eRINs and thereby reducing the effectiveness of an eRIN program at incentivizing the increased use of renewable electricity as transportation fuel. We request comment on means of overcoming the challenges presented by adopting such a hybrid structure as the basis of the eRIN program.

5. Renewable Electricity Credit Programs

While most of the alternatives stakeholders have raised concern the

[272] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects," available in the docket.

demonstration that the renewable electricity was used as transportation fuel, some stakeholders have also suggested an alternative for the demonstration that the renewable electricity was produced from renewable biomass. Specifically, some stakeholders have suggested to EPA that we consider somehow relying on or leveraging existing state renewable electricity credit (REC) programs in the development and implementation of an eRIN program. REC trading systems are a feature of many state-level renewable portfolio standard (RPS) programs, which set targets for renewable electricity use in a given area. RECs provide a mechanism to help track and account for electricity generated from renewable sources (*e.g.,* solar, wind) as it flows onto a commercial electric grid. Stakeholders have pointed EPA to such RPS programs, and mechanisms like RECs, because the programs face a similar challenge in accounting for and tracking a fungible product—renewable electricity. Many stakeholders are familiar with how REC programs function; California's LCFS, for example, allows participants to use RECs to demonstrate supply of low carbon-intensity electricity for purposes of claiming LCFS credit.[273] To avoid the double counting of electricity in multiple states, as parties generate LCFS credits for the renewable electricity that they produce, they must then retire RECs that they purchase.

We recognize the similar conceptual challenges that RPS programs and a renewable electricity program under RFS face with respect to tracking/accounting mechanisms for fungible renewable electricity. And EPA considered whether we could, in fact, rely on REC programs for compliance purposes under an eRIN program. Upon investigation, however, it became apparent that we cannot not rely on the REC program for a number of reasons. First, under the Clean Air Act's definition of renewable fuel, only electricity that is produced from qualifying renewable biomass is eligible to generate eRINs. Thus, EPA's existing renewable electricity pathways are for biogas that is produced from qualifying renewable biomass. In contrast, REC programs include, and in fact are dominated by other forms of renewable electricity such as wind, solar, and hydroelectric. Such electricity does not meet the statutory requirement of being produced from ''renewable biomass.'' As a result, it would not be sufficient for us to simply rely on RECs as a means of demonstrating that renewable electricity was produced from qualifying renewable biogas under the RFS program. Although it is true that RECs can be generated for electricity produced from qualifying biogas, the generation of a REC does not by itself indicate that the electricity meets Clean Air Act requirements. Consequently, if we were to attempt to utilize REC programs in a similar fashion to the California LCFS program, we would still need to create additional regulatory requirements. These additional regulatory requirements would likely largely resemble those we either already have or are proposing in this action to ensure that CAA requirements are met, so there would be little value in leveraging REC generation.

Furthermore, the lack of a centralized, national REC clearinghouse would complicate our relying on REC programs. An eRIN program will be national in scope, and the diversity that exists among different state-level and regional REC programs with respect to structures, capabilities and requirements would make it difficult to rely upon RECs for a federal eRIN program. Again, in order to establish a national REC program that ensures that renewable electricity was generated using qualifying biogas consistent with Clean Air Act requirements, we would have to impose a set of regulations that would look very similar to the existing RFS program or our proposed approach for the eRIN program.

Third, we cannot delegate our compliance and enforcement responsibilities to the state REC programs. Therefore, even if we somehow leverage REC programs, we would still need to have some way of reviewing, auditing and verifying the validity of the data on which eRINs would then be generated. The varied structure and limited geographic reach of these programs again precludes their use for eRINs.

Finally, a key element of the existing RFS program provisions is that the financial incentives created by RINs for expanding the use of renewable fuels are incremental to the incentives created by other federal, state, and local programs. For example, the revenue from the sale of RINs for renewable fuels is in addition to revenue from California LCFS credits; revenue from RINs therefore helps lower the cost of such programs. However, if we were to leverage state REC programs for renewable electricity under the RFS program, we would likely have to require the retirement of RECs upon the generation of eRINs in order to prevent double counting of eRINs.[274] This would negate the ability of the eRIN to further subsidize the expanded use of renewable electricity. We believe that the electricity producer should continue to benefit from the sale of the REC while also benefiting from revenue from the eRIN so long as the biogas used to produce the renewable electricity and the renewable electricity itself is not double counted.[275]

We seek comment on how, under our proposed approach, EPA might be able to rely on, leverage, or otherwise incorporate REC-program approaches.

I. Equivalence Value for Electricity

1. Background

The CAA establishes target volumes of renewable fuel to be attained in various years but does not prescribe exactly how those gallons should be counted across the range of potential renewable fuel types. For instance, the statute permits biogas to qualify as a renewable fuel for purposes of compliance with the applicable standards, but biogas cannot be easily measured in volumes in the same way that liquid renewable fuels can. Instead, the statute directs EPA to determine the appropriate basis for how credits for volumes of renewable fuels would be granted. To this end, in the 2007 final rule which established the RFS1 program, we established ''equivalence values'' unique to each biofuel that determine how many RINs can be generated for each physical gallon and how each gallon counts towards meeting the applicable standards.[276]

In the 2007 rule, we assessed several ways of determining equivalence values. Since one goal of the RFS program was reduction of GHG emissions, we considered use of lifecycle GHG scores, meaning that biofuels with lower

[273] *https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/guidance/lcfsguidance_19-01.pdf.*

[274] For example, to prevent double counting of the REC, under the California LCFS program, any RECs are required to be retired upon the generation of LCFS credits.

[275] EPA does not permit the generation of a RIN for a volume of biogas used to produce renewable CNG/LNG if the same volume of renewable biogas has been or will be used to generate a REC. This is because such a practice would constitute double counting of the biogas as being used to both generate electricity and be compressed/liquefied for transportation use; it is not physically possible for a single volume of biogas to be used in both ways. Because we have not registered any party to generate eRINs, we have not yet been confronted with a situation in which a party wishes to generate both a REC and a RIN based on the same volume of biogas combusted to generate electricity.

[276] 72 FR 23918 (May 1, 2007). We are not revisiting or seeking comment on the question of our statutory authority to set equivalence values or the basis we're using (*i.e.,* ethanol equivalent), which were established in the 2007 rule. Rather, we are only requesting comment on changing the equivalence value for electricity.

lifecycle GHG emissions could be given higher value. However, we determined that there was too much uncertainty at that time in the available information and modeling tools, and we anticipated a need to update the equivalence values periodically as the science evolved. Ultimately, we determined that, in light of the statute's requirement that qualifying renewable fuel be ''used to replace or reduce the quantity of fossil fuel present in a transportation fuel,'' volumetric energy content was the appropriate basis for equivalence values, stating that ''fossil fuels such as gasoline or diesel are only replaced or reduced to the degree that the energy they contain is replaced or reduced.''

We also noted in the 2007 rule that denatured fuel ethanol was likely to be the predominant biofuel expected to be used to meet the statutory volume targets under the RFS1 program. Thus, in an effort to establish a simple and stable program, we opted to use the energy content of renewable fuels as the basis of equivalence values and to designate denatured fuel ethanol as the baseline gallon of renewable fuel. Under this structure, credits for renewable fuels under the RFS program have been determined based on their energy content relative to denatured fuel ethanol; specifically, equivalence values are based on the ratio of a given biofuel's volumetric energy content relative to the volumetric energy content of denatured fuel ethanol. The regulations specify the equivalence values for a number of renewable fuels that we expected would be used.[277] Table VIII.G.1–1 shows the energy content and equivalence values (statutory gallons, or RINs) for several liquid renewable fuels.

TABLE VIII.I.1–1—RIN EQUIVALENCE VALUES FOR VARIOUS LIQUID RENEWABLE FUELS

Fuel type	Energy content (Btu/gal)	Equivalence value
Ethanol	77,000	1.0
Biodiesel	115,000	1.5
Renewable diesel	130,000	1.7
Butanol	100,000	1.3

For renewable fuels that the regulations do not provide an equivalence value, the regulations provide a formula for calculating the equivalence value.

The use of denatured fuel ethanol as the baseline gallon of renewable fuel for the RFS program provides a convenient and straightforward way to determine the equivalence value for all biofuels, including non-liquid biofuels. That is, 77,000 Btu of any biofuel can generate 1 RIN for purposes of compliance with the applicable standards under the RFS program. For renewable natural gas with an energy density of 1,000 Btu per cubic foot, one gallon of ethanol is equivalent to 77 cubic feet. This same basis applies to electricity by dividing 77,000 Btu per gallon by 3,412 Btu per kWh to arrive at an equivalence value of 22.6 kWh per statutory gallon.

While the energy content-based equivalence values provide the same credit value for each fuel on an energy equivalent basis, they then also provide different values on a volumetric basis. Thus, they have a first order impact on the revenue renewable fuel producers receive from RINs. For example, at a D6 RIN value of $1.00, a gallon of corn ethanol receives $1.00 whereas a gallon of conventional biodiesel receives $1.50. At a D3 RIN value of $3.00, a gallon of cellulosic ethanol receives $3.00, whereas a gallon of cellulosic renewable diesel receives $5.10.

2. Rationale for Revision

As discussed in Section VIII.A above, the 2016 REGS proposal requested comment on several eRIN-related topics, including the equivalence value for electricity used as transportation fuel. The preponderance of commenters argued that EPA should revise the equivalence value to allow for the generation of more eRINs for a given quantity of renewable electricity, which would provide greater value for that renewable electricity.[278] A common argument was that a given quantity of biogas used to produce renewable electricity would receive less credit in the RFS program (fewer RINs) than if it were used as RNG, due the energy loss in the conversion from gas to electricity. Despite the addition of eRINs to the RFS program, commenters believed the result might still be little generation of eRINs given the far greater incentive for the use of the biogas as RNG if the basis for equivalence values (*i.e.,* energy content of the fuel) remained unchanged.

Another point raised by several stakeholders is that an energy content-based equivalence value does not take into account the much greater efficiency of the electric vehicles themselves. Energy content-based equivalence values may work well when comparing fuels that are all combusted in internal combustion engines, but they argued that this does not treat electricity appropriately given its much greater end-use efficiency. Here, the comments suggested refocusing credits on the energy efficiency of electricity generation, vehicle powertrains, or some combination of the two.

Other stakeholders have asked us to address the ''point of measure'' (POM) issue that concerns the energy losses associated with electricity generation. In other words, depending on where one measures the energy in the eRIN generation/disposition chain, the resulting RIN generation is considerably different. Specifically, if one measures the energy at the point where the biogas feedstock is produced, more than three times the RIN revenue is provided than if one measures the energy after that same biogas is used to produce renewable electricity, even though there is no difference in the electrical energy produced or the distance an electric vehicle can travel using this energy.

Modifying the basis for equivalence values in one or more of these ways could address the issues raised by stakeholders and would provide greater credit value for eRINs and consequently a greater incentive for EV and renewable electricity growth.

3. Proposed Equivalence Value for Renewable Electricity

We are proposing to change the equivalence value for renewable electricity to account for system inefficiencies in both the RNG (CNG/LNG vehicle fueling) and electricity (EV charging) supply chains to ensure approximately equivalent RIN generation between the two for a given amount of biogas. In doing so, the

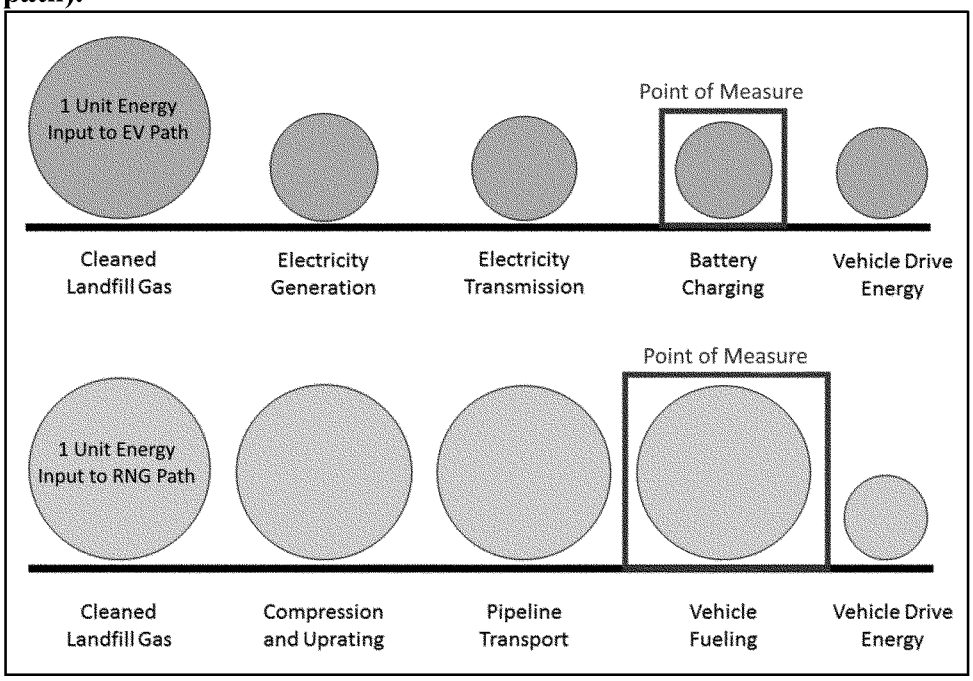
[277] See 40 CFR 80.1415.

[278] See docket EPA–HQ–OAR–2016–0041.

equivalence value for RNG is not being altered. The proposed approach seeks to establish and maintain equivalence values for renewable electricity and RNG, respectively, that are consistent with the statutory goal of displacing petroleum-based fuels in the transportation sector. This approach also seeks to establish an equivalence value for renewable electricity that is consistent with the existing structure of the RFS program in which equivalence values are determined based on the energy content of the fuel, rather than attempting to account for vehicle efficiency. Relative to the existing equivalence value for renewable electricity this proposed change would allow for a greater number of RINs to be generated for renewable electricity. The information used to calculate the proposed equivalence value for renewable electricity is discussed in greater detail in DRIA Chapter 6.1.4.

The POM issue is a key starting point for understanding the need to revise the equivalence value for renewable electricity. In general, parties generate RINs based on the quantity of renewable fuel supplied at the POM and the applicable equivalence value. Figure VIII.I.3–1 illustrates how one unit of landfill-derived RNG energy flows through the supply chain to fuel either an electric vehicle (upper path) or a CNG/LNG vehicle (lower path), where each circle's area approximates the fraction of useful energy that remains after each step. The boxes around the fourth circle indicate the POM where the energy is transferred to the vehicle, either at a RNG refueling station or an EV charger.

Figure VIII.I.3-1: Illustration of the impact of point-of-measure for landfill gas used to power electric vehicles (upper path) or as RNG for CNG/LNG vehicles (lower path).



As the diagram makes clear, this POM produces a very different measure of fuel energy for electricity than for RNG. In the case of electricity, the initial conversion of the biogas's chemical energy to mechanical energy occurs upstream of the POM in the EGU, and this step results in a significant loss of useful energy. In the case of RNG, in contrast, there is no upstream conversion and, while energy losses occur, they essentially all occur when the chemical energy in the fuel is converted to drive energy on board the vehicle after the POM. The net result of this difference is that the number of available RINs for EV charging is heavily discounted relative to the RNG pathway for the same biogas input. Thus, the existing POM significantly disadvantages renewable electricity relative to RNG used as renewable CNG/LNG, because while both supply chains experience energy losses prior to powering a vehicle, the relatively inefficient combustion of RNG occurs prior to the POM for electricity, but after the POM for direct use in a CNG/LNG vehicle.

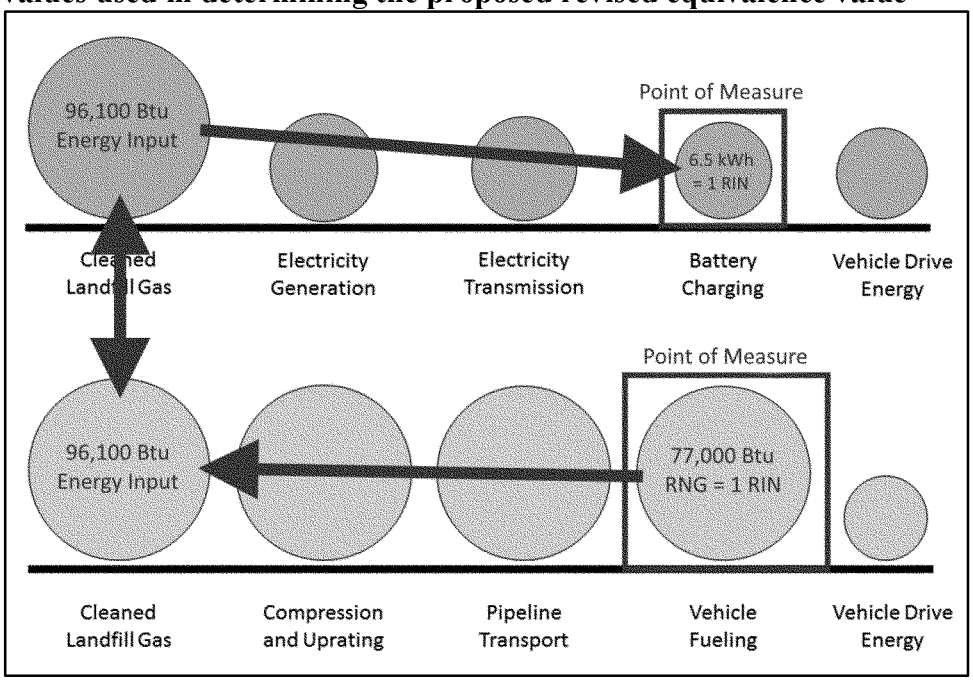
We believe this existing approach arbitrarily penalizes the use of biogas-derived renewable electricity and are therefore proposing to revise the equivalence value. Our proposed revision does not change or add POMs, but rather considers key steps or processes along the energy supply chains that significantly affect the amount of useful energy delivered to the transportation application. For the renewable electricity pathway this includes generation, transmission, and EV battery charging, and for the RNG pathway, compression and pipeline transport of the fuel. Essentially, we summed up the energy losses between the two POMs and incorporated those into the proposed electricity equivalence value in order to put them on more equitable footing. Figure VIII.I.3–2 summarizes this approach by overlaying arrows and values onto the previous diagram indicating the flow of our computation.

In determining the proposed revised equivalence value, we first analyzed the efficiencies and losses associated with biogas used in CNG/LNG vehicles using information from an Argonne National Labs analysis of landfill gas

pathways [279] and from EIA's published values on natural gas consumption and delivery.[280] Production and delivery of biogas upgraded to RNG and used as renewable CNG/LNG includes collection of the biogas, purification to produce RNG, and compression processes to transfer it onto a pipeline and into a vehicle tank. Accounting for the range of data available, this analysis indicates a central estimate of 96,100 BTU of input energy is required to deliver 1 RIN (77,000 Btu) of RNG to the vehicle.

We then analyzed the efficiencies and losses associated with converting 96,100 BTU of biogas energy into electricity for delivery to an EV. Starting with the assumption that the electrical generation unit (EGU) would draw the raw biogas (same assumption for the 96,100 BTU as input for RNG), we applied a factor of 28.8 percent for EGU thermal efficiency and 5.3 percent for transmission line losses based on information in EPA's eGRID database.[281] A literature review on EV charging efficiencies is presented in DRIA Chapter 6.1.4.4, and suggests a charging efficiency range of 80–90 percent for common EV charging configurations. Overall, we derive a central estimate of 22,300 BTU of electrical energy delivery to the vehicle battery in correspondence to 1 RIN of biogas energy delivery to a CNG/LNG vehicle. Dividing this value by 3,412 Btu/kWh to convert to kilowatt-hours produces an equivalence value of 6.5 kWh per RIN. We propose that this revised equivalence value for renewable electricity produced from biogas would replace the value of 22.6 kWh per RIN that is currently in the regulations. A more detailed discussion of the derivation of the 6.5 kWh equivalence value is available in DRIA Chapter 6.1.4.4.

Figure VIII.I.3-2: Illustration of the computation pathway (arrows) and energy values used in determining the proposed revised equivalence value



In addition to our proposed approach, we also considered the alternative approaches suggested in comments on the REGS rule. One potential alternative considered was to change the POM for electricity such that it occurs prior to electricity generation (placing the POM box in Figure VIII.I.3–2 around or just after the first circle). This would allow for the same number of RINs to be generated for biogas whether it is used in CNG/LNG vehicle or in generating renewable electricity without increasing the equivalence value for electricity. However, there are several downsides to changing the POM for electricity. First, allowing RIN generation for electricity on the basis of the biogas used to produce the electricity could create difficulty in matching RIN generation (which would be done on the basis of biogas production) and use of the fuel as transportation fuel (which would be a measure of electricity used to charge an EV). Second, in years for which the use of electricity as transportation fuel is the limiting factor for RIN generation, using biogas consumption for electricity generation as the basis for RIN generation would favor less efficient electricity generators, as these parties would combust higher quantities of biogas (and thus generate more RINs) for the same quantity of electricity used as transportation fuel.

We also considered an equivalence value based on the efficiency of an electric vehicle relative to a vehicle with an internal combustion engine. Conceptually this approach would seek to give a similar number of RINs to renewable fuels that transport a vehicle the same distance. For example, this approach would seek to provide a similar quantity of RINs for fuel that powers a vehicle for 100 miles, whether that fuel was RNG or electricity. By taking into account the much higher

[279] M. Mintz, J. Han, M. Wang, and C. Saricks, ''Well-to-Wheels Analysis of Landfill Gas-Based Pathways and Their Addition to the GREET Model'', Center for Transportation Research, Energy Systems Division, Argonne National Laboratory. 2010. Report ANL/ESD/10–3.

[280] U.S. Natural Gas Consumption by End Use, U.S. Department of Energy, Energy Information Administration. June 2021.

[281] eGRID 2019 Technical Guide, prepared by Abt Associates for U.S. EPA Clean Air Markets Division, February 2021.

efficiency of an electric motor relative to an internal combustion engine, this approach would offset the disadvantage of measuring renewable electricity after biogas has been combusted. This approach, however, would be a significant departure from the existing structure of the RFS program, which currently does not take vehicle efficiency into account when determining the number of RINs generated per gallon of renewable fuel. The same number of RINs are generated for biofuels used in all vehicles, whether those vehicles are relatively efficient or inefficient. Further, accounting for the efficiency of a vehicle in the equivalence value of a fuel would introduce significant complexity into an already complex eRIN program. To do so we would either need to determine a single equivalence value that reflects an average of the wide variety of electric vehicle efficiencies, or alternatively, use different equivalence values for different vehicles or categories of vehicles.

While we are not proposing to use this approach to determine the equivalence value for electricity, we note that equivalence values suggested by others using such an approach are similar to our proposed value. For example, the International Council on Clean Technologies, in their comments on the REGS rule, suggested a value of 5.24 kWh per RIN. The California LCFS program uses a different structure for credit generation that provides an energy equivalence ratio multiplier to account for the higher efficiency of electric vehicles. Applying California's multiplier for light-duty vehicles (3.4) to the existing RFS equivalence value of 22.4 kWh per RIN produces an equivalence value of 6.6 kWh per RIN.

We request comment on our proposed approach to revising the equivalence value for electricity. Additionally, we request comment on the threshold issues of whether to change the equivalence value for electricity in the first instance and, if so, what approach should be used and what the new equivalence value should be. We invite commenters to submit any relevant data that would help inform the equivalence value for electricity.

J. Regulatory Structure and Implementation Dates

1. Structure of the Regulations

Due to the comprehensive nature of the proposed eRIN provisions, we believe that it makes sense to create 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 proposing to create a new subpart E in 40 CFR part 80. This new subpart would include provisions not only for biogas and RNG used to produce renewable electricity, but also for other biogas-derived renewable fuels including biogas used in CNG/LNG vehicles and cases where biogas is used as a biointermediate. Existing provisions for these fuels under subpart M would be moved into the new subpart E.

Based on our general approach adopted in the Fuels Regulatory Streamlining Rule,[282] we are proposing to structure the new subpart for biogas-derived renewable fuels as follows:

- Identify general provisions (*e.g.,* implementation dates, definitions, etc.);
- Articulate the general requirements that apply to parties regulated under the subpart (*e.g.,* biogas producers, renewable electricity generators, and renewable electricity RIN (eRIN) generators); and then
- 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 would 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.

2. Implementation Dates

As described in Section VIII.E.4, we are proposing to allow for eRIN generation to begin January 1, 2024. In order to accommodate eRIN generation on January 1, 2024, we are proposing to begin implementation of the eRINs provisions as soon as the rule is effective (anticipated to be 60 days after publication of the final rule in the **Federal Register**). This means that we would begin accepting registration submissions for parties that elect to participate in the proposed eRINs program beginning 60 days after publication of the final rule in the **Federal Register**. However, while we would begin accepting registration upon the effective date of the final rule, for the reasons described in Section VIII.E.4, we believe that the generation of eRINs cannot reasonably begin at this time.

We recognize that due to the large number of parties that may want to register to produce biogas and renewable electricity to generate RINs for renewable electricity used for transportation, these parties may have difficulty in arranging for third-party engineering reviews, preparing registration submissions, and having EPA process and accept those registration materials prior to January 1, 2024. For instance, based on EPA's Landfill Methane Outreach Program (LMOP) data, we believe there are currently somewhere between 400 and 600 landfills in the U.S. that may be capable of registering in order to use the biogas they produce for the purpose of eRIN generation.[283] Additionally, according to EPA's AgSTAR data, we believe there are somewhere between 100–200 agricultural digester-to-renewable electricity generation projects.[284] We believe it is possible that some facilities that are able to produce qualifying biogas or renewable electricity may not be able to complete all the necessary steps that would allow EPA to accept that registration before January 1, 2024. If we do not provide flexibility for the delayed generation of eRINs, we would limit the near-term generation of eRINs to only those parties that submitted their registrations first, despite other parties producing qualifying biogas and renewable electricity. We believe this would ultimately create an unlevel playing field whereby only some, typically larger, renewable electricity generators would be able to start generating eRINs on January 1, 2024, while others would not. We believe that larger renewable electricity generators would be unfairly advantaged because they would be more able to pay a premium for third-party engineers to conduct site visits and hire consultants to prepare and submit registration materials. This would additionally make our estimation of eRIN generation during the first year of the program difficult and undermine certainty in the proposed volumes.

To address this potential scenario, we are proposing a temporary flexibility with regard to the acceptance of registrations related to eRINs. Under the current RFS regulations, we do not allow a party to generate RINs until after EPA has accepted its registration. Applying this to the start of eRINs would mean that in order for an eRIN to be generated, all three core parties (*i.e.,* the biogas producer supplying the biogas, the renewable electricity generator generating the renewable

[282] See 85 FR 78415–78416 (December 4, 2020).

[283] For more basic information on landfill gas energy projects included in the LMOP data, see *https://www.epa.gov/lmop/basic-information-about-landfill-gas.*

[284] For more information on agricultural digester to electricity projects included in AgSTAR data, see *https://www.epa.gov/agstar/livestock-anaerobic-digester-database.*

electricity, and the light-duty OEM generating the eRIN) must complete registration by January 1, 2024. Given the challenges associated with this at the program startup we are proposing that OEMs would be permitted to generate eRINs for renewable electricity produced from qualifying biogas produced from January 1, 2024 through April 30, 2024, without the associated biogas producers and renewable electricity generators having an EPA-accepted registration so long as all of the following conditions are met:

- The biogas producer submitted a registration request with a third-party engineering review report to EPA no later than December 31, 2023.
- The renewable electricity generator submitted a registration request with a third-party engineering review report to EPA no later than December 31, 2023.
- Neither the biogas producer nor renewable electricity generator substantially alters their facilities after the third-party engineering review site visit.
- The biogas was produced after the third-party engineering review site visit.
- The renewable electricity generator contracted with the eRIN generator for the RIN generation allowance from their renewable electricity prior to January 1, 2024.
- The renewable electricity was generated between January 1, 2024, and March 31, 2024.
- The biogas producer, renewable electricity generator, and eRIN generator meet all applicable requirements under the RFS program for the biogas, renewable electricity, and RINs.
- EPA accepts the registrations for the biogas producer and/or the renewable electricity generator by April 30, 2024.

Under this proposal, parties would essentially have until the first quarterly RIN generation deadline in 2024 for EPA to accept their registration submission. Under this proposal, this would be 30 days after the end of the first quarter in 2024, or April 30, 2024. We believe this is enough time for EPA to reasonably approve all timely registration submissions. We have adopted flexibilities to address similar concerns in the past. For example, in 2010 we provided flexibilities for delayed RIN generation while EPA transitioned from RFS1 to RFS2 and when EPA was in the process of approving new pathways.[285]

We note that if EPA does not accept registration materials needed for the generation of eRINs from a biogas producer or renewable electricity generator by April 30, 2024, the OEM would not be able to generate RINs. We also note that parties that do not meet the conditions of this proposal would still be able to register to generate eRINs, but their biogas or renewable electricity would not be able to take advantage of this proposed flexibility. Instead, OEMs could rely on the biogas or renewable electricity for eRIN generation only after EPA has accepted the registrations for the biogas producer and/or renewable electricity generator.

We seek comment on our proposal to begin implementation on the effective date of the rule and begin eRIN generation for renewable electricity produced from qualifying biogas on January 1, 2024. We also seek comment on our proposal to allow RIN generation for the first quarter of 2024 under certain circumstances to provide more time for parties and EPA to process registration submissions related to eRINs. We are particularly interested in whether EPA should provide more time for parties to submit and EPA to accept eRIN related registration submissions.

K. Definitions

We are proposing definitions of the various regulated parties, their facilities, and the products related to the production of biogas-derived renewable fuels. We are also proposing to define other terms as necessary for clarity and consistency. We are also proposing to move and consolidate all defined terms for the RFS program from 40 CFR 80.1401 to 40 CFR 80.2. We are doing this because we moved all of the non-RFS fuel quality regulations from 40 CFR part 80 to 40 CFR part 1090 as part of our Fuels Regulatory Streamlining Rule.[286] As such, it is no longer necessary to have a separate definitions section for 40 CFR subpart M, as only requirements related to the RFS program are housed in 40 CFR part 80. We are not proposing to change the meaning of the terms moved from 40 CFR 80.1401 to 40 CFR 80.2, but are simply relocate them to consolidate the definitions that apply to RFS in a single location. For these relocated terms, we are not proposing to amend their meaning and any comments on the relocated terms will be considered beyond the scope of this rulemaking. We are proposing to add any newly defined terms under this proposal to 40 CFR 80.2.

For parties regulated under the proposed eRIN and biogas regulatory reform provisions (the latter discussed in Section IX.I), we are proposing several new terms to specify which persons and parties are subject to the proposed regulatory requirements in a manner that is consistent with our approach under our other fuel quality and RFS regulations. For example, we are proposing that a biogas producer would be any person who owns, leases, operates, controls, or supervises a biogas production facility, and a biogas production facility would be any facility where biogas is produced from renewable biomass that qualifies under the RFS program. We propose the same framework for RNG producers and renewable electricity generators. We are proposing to define the eRIN generator, *i.e.,* a light-duty OEM, as any OEM of light-duty vehicles or light-duty trucks who generates RINs for renewable electricity.

Under the existing 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 proposing specific definitions for biogas-derived renewable fuel, biogas (or raw biogas), biomethane, and renewable natural gas (RNG). These new terms would apply to the proposed eRINs program as well as the biogas regulatory reform provisions discussed in Section IX.I.

Because ''biogas'' is often used to broadly mean any renewable fuel used in the transportation sector that has its origins in biogas, we are proposing a more descriptive and inclusive term of ''biogas-derived renewable fuel.'' Under this proposal, biogas-derived renewable fuels would include renewable CNG, renewable LNG, renewable electricity, or any other renewable fuel that is produced from biogas or its pipeline-quality derivative RNG now or in the future.

Under this proposal, we would define biogas (sometimes referred to as raw biogas) as a mixture of biomethane, inert gases, and impurities that is produced through the anaerobic digestion of organic matter prior to any treatment to remove inert gases and impurities or adding non-biogas components. We have proposed to update this definition to make more explicit that this definition refers to the biogas collected at landfills or through a digester before that biogas is either upgraded to produce RNG or is used to make a

[285] 75 FR 76790 (December 9, 2010).

[286] 85 FR 78417–78420 (December 4, 2020).

biogas-derived renewable fuel, which was intended but not stated in the previous definition.

We are proposing to define biomethane as exclusively methane produced from renewable biomass (as defined in 40 CFR 80.1401). We believe a separate definition for biomethane is important because biomethane (exclusive of impurities, inert gases often found with biomethane in biogas) is what renewable electricity and eRIN generation is based on. In order to ensure the appropriate measurement of biomethane for RIN generation for RNG, we have issued guidance under the existing regulations that cover cases where non-renewable components are added to biogas.[287]

To describe biogas-derived pipeline-quality gas, we are proposing to adopt a term now in common use, renewable natural gas or RNG. Under this proposal, in order to meet the definition of RNG, the product would need to meet 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.
- The gas must be designated for use to produce a biogas-derived renewable fuel.

We are proposing that RNG must contain at least 90 percent biomethane content because we believe this is 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 do, however, seek comment on whether a different biomethane content would be more appropriate.

EPA's existing 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.[288] We are proposing to codify this guidance in our regulations as part of the proposed definition of RNG. As a result, registration submissions for RNG under the RFS program would require the submission of these pipeline specifications and we are proposing a definition of RNG that would require gas to meet those pipeline specifications.

We are also proposing that RNG be defined such that it only meets the definition if the gas is designated for use to produce a biogas-derived renewable fuel under the RFS program. We are proposing 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. We believe such an 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.

We have incorporated the use of these new proposed definitions in both the new 40 CFR part 80, subpart E proposed regulations for biogas derived renewable fuels, and 40 CFR part 80, subpart M where applicable. We seek comment on these proposed definitions and on whether there are other terms that we should define. If suggesting a newly defined term, commenters should also provide a suggested definition for that term.

L. Registration, Reporting, Product Transfer Documents, and Recordkeeping

We are proposing compliance provisions necessary to ensure that the production, distribution, and use of biogas, renewable electricity, and eRINs are consistent with Clean Air Act requirements under the RFS program. These proposed compliance provisions include registration, reporting, PTDs, and recordkeeping requirements. We discuss each of these compliance provisions below.

1. Registration

Under the RFS program, we require biointermediate and renewable fuel producers 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 initially 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 RINs.

To that end, we are proposing that biogas producers, renewable electricity generators, eRIN generators, and RNG producers would be required to register with EPA prior to participation in the RFS program. Under this proposal, biogas producers, RNG producers, and renewable electricity generators would have to submit information that demonstrates that their facilities are capable of producing biogas, RNG, or renewable electricity from renewable biomass under an EPA-approved pathway. This information would include the feedstocks that the producer or generator intends to use, the process through which the feedstock is converted into biogas, RNG, or electricity, and any other information necessary for EPA to determine whether biogas, RNG, or electricity were produced in a manner consistent with Clean Air Act and EPA's regulatory requirements. Such information is necessary to ensure that eRINs are generated only for renewable electricity generated from qualifying biogas. Biogas producers, RNG producers, and renewable electricity generators would also have to 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, RNG, or renewable electricity to help identify potential fraud. Like biointermediate production and renewable fuel production facilities, we are proposing that biogas production, RNG production,[289] and renewable electricity facilities 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, RNG, or renewable electricity consistent with Clean Air Act and EPA regulatory requirements.

Under this proposal, like other RIN generators, OEMs that want to generate eRINs would have to register with EPA under the RFS program to be able to generate and transact RINs in EMTS and to submit required periodic reports. We

[287] 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.

[288] 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.

[289] See 40 CFR 80.1450(b)(2).

are also proposing that, in addition to basic registration information for the company required of all registrants under EPA's fuel programs,[290] OEMs would have to submit information to EPA for their anticipated light-duty electric vehicle fleet size and disposition. This information is needed to serve as a baseline for total potential eRIN generation and would be used by EPA and third parties to evaluate whether OEMs generate an appropriate amount of eRINs based on the amount of renewable electricity that an OEM can demonstrate was used in its light-duty electric vehicle fleet as discussed in Section VIII.F.5. OEMs would update their light-duty electric vehicle fleet size and disposition information via the quarterly reporting requirements discussed in Section VIII.N.2.

We are also proposing that biogas producers, renewable electricity generators, and OEMs 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. As discussed in Section VIII.F, biogas producers that directly supply a renewable electricity generation facility with biogas through a private, closed pipeline would need to associate with that renewable electricity generation facility via their registration with EPA and must supply their biogas to the associated renewable electricity generation facility. Similarly, for each renewable electricity generation facility, renewable electricity generators would have to associate with the OEM to which they have established their RIN generation agreement. We are proposing that this be monitored via registration because our registration system is currently set up to track these kinds of relationships. Similarly, for renewable electricity generators, we propose to track the association related to the transfer of RIN generation agreement to OEMs via the registration process.

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 VIII.L.2) would have to 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 would have to register in accordance with existing requirements under 40 CFR parts 1090 and 80 using forms and procedures specified by EPA. We are not proposing changes to this existing requirement.

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 biogas-derived renewable CNG/LNG in 40 CFR 80.1451. We are proposing similar reporting requirements for biogas producers, renewable electricity generators, eRIN generators, and RNG producers.

For biogas producers, we are proposing quarterly batch reports that would 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 would break down each batch by D-code, by digester, and by designated use of the biogas. The designated use of the biogas includes whether the biogas would be used to make renewable CNG/LNG via a closed, private pipeline system; RNG; on-site renewable electricity; or other use as a biointermediate. This information is necessary for us 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 need the information at the digester level for each biogas facility because we have determined, based on our current registrations, that some biogas production facilities have multiple digesters that produce biogas using different D-codes for different end uses. Without reported data at this level, it would be difficult if not impossible for third-party auditors and EPA to conduct effective audits of the facility. Additionally, Biogas producers will enter these quarterly batch reports directly into EMTS and transfer each batch to a renewable electricity generator in EMTS. This improved electronic reporting process is intended to improve the quality of information, enable better information sharing between parties, including third-party auditors, and define a structured reporting process.

For renewable electricity generators, we are proposing quarterly reports to support the amount of renewable electricity generated from qualifying biogas. Under these quarterly reports, renewable electricity generators would report the amount and energy content of biogas or RNG used to produce renewable electricity and the quantity of renewable electricity generated and placed onto the commercial electric grid serving the conterminous U.S. Renewable electricity generators would break down the quantity of renewable electricity generated by month, by EGU, and D-code. Renewable electricity generators would also need to identify which electricity is attributed to their designated OEM. For RNG co-processed with natural gas, we would require that renewable electricity generators report the amount of natural gas feed used to help ensure that eRINs are not generated for non-renewable electricity. Similar to the biogas reports, these reporting requirements are necessary to demonstrate the amount of renewable electricity produced from qualifying biogas, to describe the amount of renewable electricity placed on the commercial electric grid serving the contiguous U.S., and to help track which quantities of renewable electricity were supplied to eRIN generators. Similar to the reporting procedure for biogas producers, renewable electricity generators will enter these batch reports into EMTS and transfer the batch information to the OEM in EMTS. A batch of renewable electricity entered into EMTS would be directly connected to a corresponding amount of biogas batches within the renewable electricity generator's EMTS holdings. This process will ensure the batch information has been properly reported and transferred between parties. The reports would also serve as the basis for third-party verification and EPA audits to help ensure the validity of eRINs.

Under our proposal, OEMs that participate in the program as eRIN generators would be subject to all applicable reporting requirements for RIN generators under the current program. These requirements would

[290] For basic registration information, see 40 CFR 1090.805.

include the RIN generation reports,[291] RIN transaction reports,[292] and the RIN activity reports.[293] Prior to the generation of any RINs, OEMs would also be required to receive the corresponding transfer of the renewable electricity batches in EMTS demonstrating the renewable electricity batch was transferred and reporting requirements were completed. As the RIN generator, the OEMs would also be responsible for generating RINs in EMTS as well as separating and transacting the RINs.[294] These reporting requirements are necessary to allow for the generation of eRINs and are required of any party that generate RINs under the RFS program.

In addition to the reporting needed to administer the generation, separation, and transaction of RINs, we are proposing two additional reporting requirements for OEMs that generate eRINs. First, OEMs would be required to report quarterly their light-duty EV fleet size and disposition. Because we expect these data to change quarterly and the data serve as the basis for eRIN generation, it is necessary for OEMs to update this information to ensure that the appropriate number of eRINs are generated for each OEM's light-duty electric vehicle fleet. Furthermore, these reports would serve as the basis for compliance oversight by EPA and third parties. The quarterly fleet size and disposition reports would include the actual fleet totals and characteristics for their fleet by make, model, year, and trim.[295] We are proposing that the reported fleet characteristics would include the eVMT, efficiency, and charging efficiency. This information is needed to demonstrate that the appropriate amount of renewable electricity from qualifying biogas was used as transportation fuel in the OEM's light-duty electric vehicle fleet and, as discussed in Section VIII.F.6, help refine the assumed values for eRIN generation over time.

We note that we are also proposing new reporting requirements for RNG producers. These reporting requirements are described in more detail in Section IX.

In addition to seeking comment on these reporting provisions, we also seek comment on the draft reporting forms that have been added to the docket.[296]

3. Product Transfer Documents (PTDs)

We are proposing product transfer documents (PTDs) for transfers of title for biogas and for transfers of data regarding the generation of renewable electricity between renewable electricity generators and OEMs. We have historically used PTDs to create a record trail that demonstrates the movement of product 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.[297] PTDs are important for biogas and eRINs as they are necessary to document that qualifying biogas was transferred between biogas producers and renewable electricity generators and to ensure that eRIN generators receive necessary information concerning the amount of renewable electricity placed onto the commercial electric grid serving the contiguous U.S. for transportation use. EPA and third parties would also review PTDs to help verify the eRINs were validly generated.

For biogas transfers to renewable electricity generators, we are proposing that PTDs accompany transfers of title for biogas from biogas producers to renewable electricity generators. These PTDs would include information related to the transferer and transferee, a designation that the biogas is intended for use to produce renewable electricity, the amount of biogas being transferred, and the date that title of the biogas was transferred. These proposed 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.

We note that under this proposal, no PTDs would be necessary when biogas is transferred between a biogas production facility and a co-located renewable electricity generation facility as long as the same party maintains title of the biogas and owns and operates both facilities. We also note that these PTDs would not be required in cases where title to RNG is being transferred between RNG producers and renewable electricity generators. This is because, as discussed in Section IX.I, RINs are generated upon the production of RNG, and the transfer of those RINs then serves the function that the PTD would otherwise serve. The proposed generation of RINs for RNG and associated PTD requirements are discussed in Section IX.I, which addresses our proposed biogas regulatory reform.

For transfers of information related to the generation of renewable electricity, we are proposing that renewable electricity generators would create and transfer PTDs quarterly to OEMs for the amount of renewable electricity introduced onto the commercial electric grid serving the contiguous U.S. for the quarter. These proposed PTDs would include similar information to other PTDs required under the RFS program and the proposed biogas PTDs described above. This would include information regarding the transferer and transferee of the information related to the generation of renewable electricity, the amount of renewable electricity introduced onto the commercial electric grid serving the contiguous U.S., and a statement certifying that the renewable electricity was introduced onto the commercial electric grid serving the contiguous U.S. We are proposing these PTDs be transferred quarterly to align with the proposed RIN generation procedures in Section VIII.L.3.

We note that all other applicable PTD requirements under 40 CFR part 80 would apply. For example, after OEMs have generated and separated RINs for renewable electricity, the OEMs would still need to transfer PTDs for the separated RINs when they sell those RINs to other parties. We seek comment on the proposed PTD requirements for biogas and renewable electricity.

4. Recordkeeping

We are proposing recordkeeping requirements for biogas producers, renewable electricity generators, and eRIN generating OEMs. 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 proposing to continue to require 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

[291] See 40 CFR 80.1451(b)(1)(ii).

[292] See 40 CFR 80.1451(b)(2) and (c)(1).

[293] See 40 CFR 80.1451(b)(3) and (c)(2).

[294] Requirements related to the generation, separation, and transaction of RINs in EMTS are described at 40 CFR 80.1452.

[295] For purposes of this preamble, a vehicle's trim refers to the different versions of a model that an OEM produces in a given year. Sometimes, OEMs manufacture a vehicle model that includes different trims for an ICE, PHEV, and EV version of the same model.

[296] ''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.

[297] The PTD requirements for RFS are described at 40 CFR 80.1453.

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. Specific to eRINs, we are proposing that biogas producers keep PTDs to support the fact that the biogas was transferred to renewable electricity generators.

For renewable electricity generators, we are proposing recordkeeping requirements consistent with other parties that produce renewable fuels under the RFS program. Similar to the proposed requirements for biogas producers, this would include information and documentation needed to support that the renewable electricity was produced from qualifying biogas or RNG, copies of all registration information, copies of all reports, and copies related to the measurement of renewable electricity transmitted onto the commercial electric grid serving the contiguous U.S. Renewable electricity generators that use RNG to produce renewable electricity would also have to maintain records related to separating RINs from the RNG as discussed in more detail in Section IX.I.

For OEMs, we are proposing recordkeeping requirements consistent with those of other RIN generators under the current RFS program. These records would include information received from the renewable electricity generator related to the amount of renewable electricity introduced onto the commercial electric grid serving the contiguous U.S., copies of contracts between the renewable electricity generator and the OEM to support the use of the renewable electricity generator's renewable electricity for RIN generation, and copies of all RIN generation records and reports. We would also require that OEMs keep copies of all calculations for RIN generation as well as any EMTS-related records for the generation and transaction of RINs. These records are needed to help ensure that eRINs are generated only for renewable electricity derived from qualifying biogas and used as transportation fuel.

Under the RFS program, parties that participate in the RFS QAP must maintain records related to their participation in the RFS QAP program which includes copies of contracts between the regulated party and the QAP auditor, copies of any records related to verification activities under the RFS QAP, and copies of any QAP-related submissions. For the proposed eRINs program, the recordkeeping requirements would similarly apply to parties in the eRINs generation/disposition chain that participate in the RFS QAP program. We describe in more detail how we propose the RFS QAP would work for eRINs in Section VIII.P.

We believe these proposed recordkeeping requirements for parties regulated under the proposed eRINs program are necessary to ensure proper program implementation and oversight. We seek comment on these proposed recordkeeping requirements and whether any additional recordkeeping requirements should be imposed as part of the proposed program.

M. Testing and Measurement Requirements

We are proposing to specify testing and measurement procedures for biogas, RNG, and renewable electricity. 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 generated more renewable electricity, and thus RINs, than would be appropriate. By establishing clear and consistent testing and measurement requirements, we can ensure the validity of RINs and a level playing field for RIN generators. We separately discuss the testing and measurement considerations for biogas and RNG and renewable electricity below.

1. Testing and Measurement Requirements for Biogas and RNG

For the measurement of biogas and RNG, we are proposing to incorporate currently published guidance into the regulations.[298] Under this guidance, for RIN generation purposes, we specified that parties should use in-line gas chromatography (GC) meters that provide continuous readings to measure the energy content in BTUs of the biogas after treatment to remove inert gases (*e.g.,* nitrogen and carbon dioxide) and other contaminants (*e.g.,* hydrogen sulfides, total sulfur and siloxanes) and before the biogas or RNG is injected into a commercial distribution pipeline. Also under the guidance, we allow for parties to submit for EPA-approval as part of a registration submission an alternative sampling protocol that would properly measure the energy content of the biogas after treatment. Biogas and RNG producers would submit as part of their registrations whether they were using in-line GC meters or an alternative sampling protocol. We would not require parties with already-approved alternative sampling protocols to resubmit those approvals under this proposal.

Similarly, we are also incorporating into the proposed regulations the existing guidance related to analytical testing for the registration of biogas and RNG for use in the production of a biogas-derived renewable fuel.[299] Under the current guidance, any party registering to produce renewable CNG or renewable LNG from biogas injected into a commercial pipeline must describe the technology being used to treat the biogas to get the biogas to pipeline quality prior to blending with non-renewable fuel streams, and must demonstrate that this technology is successful by submitting a certificate of analysis (COA) from an independent laboratory. Specifically, the party that registers must supply the following at registration:

- A COA for a representative sample of the raw biogas produced at the digester or landfill;
- A COA for a representative sample of the ''cleaned up'' biogas after treatment;
- A COA for a representative sample of the biogas after blending with non-renewable gas (if the biogas is blended with non-renewable gas prior to injection into a pipeline);
- Specifications for the commercial distribution pipeline into which the RNG will be injected;
- Summary table with the results of the three COAs and the pipeline specifications (converted to the same units); and
- 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.

The COAs must report 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 specifying specific standards that must be used when measuring biogas properties. These

[298] ''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.

[299] ''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.

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. We are seeking comment on the proposed standards as well as any additional standards that would ensure biogas properties are accurately measured. 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). We allow parties that cannot obtain the COAs to make an alternative demonstration for biogas and RNG quality during the registration process if they can demonstrate that the alternative demonstration is similarly robust to independent laboratory analysis.

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 proposing to codify the recordkeeping requirements for the testing and measurement of biogas and RNG as well as the requirement that third parties verify this information mentioned in the guidance.[300]

We are also specifying additional measurement requirements for RNG that is trucked to a gas pipeline interconnect. In this situation, we are proposing that 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 generated from biomethane.

We do not believe these proposed requirements would impose any additional burden on currently registered parties as the proposed requirements are in line with existing guidance and we believe all current registrants for biogas have indicated that they comply through their registrations. We seek comment on this proposed inclusion of the current biogas guidance into the regulations.

2. Metering Requirements for Renewable Electricity

For the measurement of renewable electricity transmitted to the grid, we are proposing that facilities use revenue grade meters that meet the requirements of ANSI C12.20–15.[301] Under the NTTAA, we are required to specify industry standards when appropriate, and we believe this standard is appropriate considering our need to ensure consistent, quality measurement of renewable electricity for RIN generation. Under this proposal, we would ask that third-party engineers verify that meters at renewable electricity facilities meet ANSI C12.20–15 as part of third-party engineering reviews. We are also proposing that the facilities keep records of the calibration and maintenance of meters that would also be part of 3-year registration updates and RFS QAP verification.

We recognize that many current electricity projects may not have revenue grade meters and that it may take time for these renewable electricity generators to install compliant meters. Therefore, we seek comment on whether there are alternative metering standards for renewable electricity or whether we should provide an alternative approval process if the renewable electricity generator can demonstrate that the alternative measurement method is as valid as ANSI C12.20–15. We also seek comment on whether we should temporarily allow alternative measurement methods for a period to let renewable electricity generators have enough time to install revenue grade meters and, if so, what temporary alternative measurement methods should be allowed.

N. RFS Quality Assurance Program (QAP)

We are proposing changes to the RFS QAP provisions to allow for verification of eRINs. The RFS QAP provides for auditing of biointermediate and renewable fuel production facilities by independent third-party auditors who review feedstock, process, and RIN generation elements to determine if renewable fuel production and RIN generation is consistent with EPA requirements. Once having gone through this process, the RINs generated are considered to be QAP verified (often referred to as a Q–RIN). The current RFS QAP provisions do not include the specific elements that we believe would be necessary to verify the entire eRIN generation/disposition chain.

Under this proposal, the biogas production, renewable electricity generation, and eRIN generation would all need to be verified to generate a verified eRIN (*i.e.,* Q–RIN). This would mean that the QAP auditor would have to have a pathway specific plan approved for all three parties in the eRINs production chain. As with the similar case of biointermediates where multiple parties are in the chain, the same QAP auditor would be required to conduct verification of all three facilities in order for the eRIN to be Q–RINs. We believe that this is necessary to provide the level of assurance that is expected from the RFS QAP. If we allowed the eRIN generator to generate Q–RINs without also verifying the biogas production and renewable electricity generation, it could undermine the level of compliance assurance provided by the QAP process.

We are not proposing mandatory participation in the RFS QAP for parties that participate in the proposed eRINs program. We do not believe that such a requirement is necessary due to the nature of the proposed eRINs regulatory program. We note that this contrasts with the recently finalized biointermediates program.[302] For the biointermediates program, we expressed significant concerns over the double generation of RINs from a biointermediate, which is often indistinguishable from renewable fuel, and a renewable fuel. In such cases, a party could generate a RIN for the biointermediate and a separate party could generate a RIN for a renewable fuel made from the biointermediate. We also had concerns with biointermediates being adulterated with non-qualifying feedstocks in route to the renewable fuel production facility. Therefore, on balance we believed that mandatory QAP participation was necessary to mitigate these concerns.

We do not have the same concerns with the proposed eRINs program. As discussed in Section VIII.P.1.d, we have two main concerns regarding the generation of invalid eRINs: the double-counting of the biogas or RNG (*e.g.,* one party generates a RIN for the biogas for use as renewable CNG and then another party claims the same volume of biogas was used to make renewable electricity) and the double-counting of renewable electricity to generate multiple eRINs (*e.g.,* one party claims an amount of renewable electricity through one set of data to generate eRINs and another party

[300] "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.

[301] See ANSI C12.20–20, "Electricity Meters 0.2 And 0.5 Accuracy Classes," available in the docket for this action.

[302] 87 FR 39600 (July 1, 2022).

claims the same amount of renewable electricity through a different set of data to generate additional eRINs). For the biogas and RNG that would be used to produce renewable electricity, we believe the proposed biogas regulatory reform provisions discussed in Section IX.I would address most of our double-counting and double-RIN generation concerns. Tracking the movement and use of RNG through assigned RINs in EMTS limits the ability to double-count the volume of RNG. We note, however, that should we decline to finalize the proposed provisions for biogas regulatory reform discussed in Section IX.I, we would consider it necessary to require mandatory QAP participation for eRIN participants as a mechanism to help oversee the program and avoid the double-counting of the biogas or RNG.

Regarding the double-counting of renewable electricity, we believe that the proposed conditions on RIN generation discussed in Section VIII.F.5 would virtually eliminate the possibility that renewable electricity is double-counted. The proposed many-to-one structure only allows the RIN generation allowance from a renewable electricity generator to go to a single OEM. OEMs, in turn, could only generate RINs for registered EVs in service that they manufactured. This should virtually eliminate the possibility that the renewable electricity is double counted. Furthermore, unlike biointermediates, the renewable electricity is already in its final form, so we do not have concerns that the renewable electricity would fail to be generated consistent with an EPA-approved pathway from qualifying biogas.

As is currently the case for RINs generated from biogas to renewable CNG/LNG, we do, however, believe that obligated parties and other RIN market participants would want most eRINs to be verified under the RFS QAP. While the RFS QAP provides additional assurance to obligated parties that the verified RINs (Q–RINs) are likely valid, consistent with the current regulations, obligated parties must still replace invalid Q–RINs. The regulations do allow for obligated parties to establish an affirmative defense against civil violations under 40 CFR 80.1473 as long as all elements needed to establish such a defense are met. We believe this is due to the relatively high value of cellulosic RINs and the difficulty in procuring replacement cellulosic RINs should they turn out to be invalid.

Under the proposed changes to the RFS QAP for eRINs, biogas production verification would remain substantially the same as what is currently required for biogas and RNG used to produce renewable CNG/LNG. The QAP Provider would be required to perform a site visit to the biogas production facility (*e.g.,* the landfill, agricultural digester, waste digester, etc.) and the upgrading facility for the biogas that turned it into RNG, if applicable. Auditors would verify that biogas came from qualifying renewable biomass, and any specific requirements related to the specific type of digester used to produce the biogas (*e.g.,* ensuring that separated municipal solid waste (MSW) met the requirements of an approved separated MSW plan under 40 CFR 80.1426(f)(5)(ii)(B)). As is currently required, auditors would also conduct quarterly desktop audits of registration, reports, and recordkeeping information for consistency and conformance with applicable regulatory requirements.

As with existing regulatory requirements for other fuels, the QAP auditor would be required to make site visits to the renewable electricity generation facility to verify that necessary equipment is present and that the registered capacity is accurate. The auditor would also verify that only qualifying biogas was used to produce renewable electricity. As is also currently required for RFS QAP participants, auditors would have to conduct quarterly desk audits of the renewable electricity generation facility. In addition to the typical registration, reporting, and recordkeeping review, auditors would also review PTDs from the biogas producer and renewable electricity generator to the OEMs to verify that the correct amounts of biogas and RIN generation allowances were transferred between the three regulated parties.

Finally, desk audits would be required for the eRIN generator (*i.e.,* OEM) to verify that RINs were generated accurately. We would not require a site visit of the OEM's vehicle manufacturing facilities as we do not believe that would be necessary for the verification of eRINs. As part of the quarterly desk audits, auditors would verify that the OEM only generated RINs from the lesser of the total renewable electricity represented by their RIN generation allowances or the renewable electricity used in the OEM's electric vehicle fleet based on vehicle registration records.

Although we are not proposing mandatory QAP participation for eRINs, we seek comment on whether we should require it. We also seek comment on the proposed changes to the RFS QAP to accommodate the verification of eRINs.

O. Compliance and Enforcement Provisions and Attest Engagements

We are proposing compliance and enforcement provisions for eRINs and other 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 against non-compliance, and the proposed compliance and enforcement provisions for eRINs and other biogas-derived renewable fuels would serve the same purposes. We discuss the specific proposed 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 proposing provisions that establish prohibited actions relating to the generation of RINs from biogas-derived renewable fuels; how biogas producers, RNG producers, renewable electricity generators, and RIN generators for renewable electricity and RNG would be held liable when RINs from biogas-derived renewable fuels are determined to be invalid; how biogas producers, RNG producers, and renewable electricity generators may establish affirmative defenses; and 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 existing 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, violate any requirement of the subchapter.[303] For the renewable electricity program we are proposing to adopt 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, would be

[303] See 85 FR 29034, 29075 (May 14, 2020); 40 CFR 1090.1700.

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, Renewable Electricity, and Biogas-Derived RIN Generators

We are proposing 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 proposing that when biogas, RNG, renewable electricity, or RINs from a biogas-derived renewable fuel are found to be in violation of regulatory requirements, the biogas producer, RNG producer, renewable electricity generator, and person that generated RINs from a biogas-derived renewable fuel would all be liable. Under this proposed approach, 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 represent a determination by EPA that the subsequent feedstocks and processes used 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, renewable electricity, and RINs generated from biogas-derived renewable fuel rests with all parties in the generation/disposition chain.

As noted above, this approach 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. In this case, if, for example, a biogas producer were to use feedstocks that do not meet the definition of a renewable biomass, then the biogas producer, renewable electricity generator, and RIN generator could all be liable for the violation.

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. Typically, EPA would notify the party of the compliance issue and provide an opportunity for the party to remedy the issue within 30 days before EPA deactivates the party's registration. 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 the eRINs proposal, these provisions for administrative action would apply like they do currently under the RFS program. We would intend to deactivate registrations in cases where parties in the eRIN generation/disposition 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 eRIN generation/disposition chain (*i.e.,* a biogas producer, renewable electricity generator, or OEM) would result in the prohibition of the generation of eRINs from any affected biogas, renewable electricity, or transportation use from the party whose registration was deactivated. Similarly, if EPA has approved a QAP plan for the OEM to generate a verified eRIN, if EPA revokes the QAP plan, the OEM would not be able to generate verified eRINs. We note that these administrative actions would be in addition to any civil penalties. We believe that in combination with the proposed prohibited actions, liabilities, and provisions for dealing with invalid eRINs, regulated parties in the eRINs disposition/generation chain would have a strong incentive to comply with the proposed eRINs regulatory requirement. We are not proposing to amend the existing provisions that allow for EPA to take administrative action to deactivate registrations or revoke QAP plans under the RFS program in this action, and we would consider any comments received as beyond the scope of this action.

c. Affirmative Defenses

We are proposing that biogas producers, RNG producers, and renewable electricity generators may establish affirmative defenses to certain violations if the biogas producer, RNG producer, or renewable electricity generator 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. Under this proposal, we would allow biogas producers to establish an affirmative defense so long as all the following were 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, renewable electricity, 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 the 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; and
- 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 and renewable electricity generators, we are proposing analogous requirements to establish an affirmative defense except that, instead of relating to biogas producer, the elements would relate to the RNG producer or renewable electricity

generator. We believe these elements to establish an affirmative defense would allow RNG producers and renewable electricity generators to avoid liability only in cases where they could not reasonably be expected to know that a violation took place; for example, if an OEM over-generated RINs for the volume of renewable electricity covered by a RIN generation agreement.

Under the RFS program, the RIN generator is always responsible for the validity of the RIN, and we are therefore not proposing to allow OEMs that generate eRINs the ability to establish an affirmative defense. We expect OEMs that generate eRINs, like all RIN generators under the RFS program, to diligently ensure that other parties that are part of the eRIN generation/distribution chain are meeting their regulatory requirements. Similarly, when the RNG producer generates a RIN for RNG used to make renewable CNG/LNG, the RNG producer would not be able to establish an affirmative defense.

We seek comment on these proposed affirmative defenses for biogas producers, RNG producers, and renewable electricity generators.

d. Invalid Biogas-Derived RINs

We are proposing provisions similar to the existing RFS regulations to address the treatment of invalid biogas-derived RINs. If a biogas-derived RIN is identified to be potentially invalid by the RIN generator, an independent third-party auditor, or the EPA, certain notifications and remedial actions would be required to address the potentially invalid biogas-derived 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 proposing provisions that require biogas and RNG producers to notify renewable electricity generators if they become aware that inaccurate amounts of biogas or RNG were transferred to the renewable electricity generator. Similarly, the provisions require renewable electricity generators to notify OEM eRIN generators if they become aware that inaccurate amounts of renewable electricity were transferred to the biogas-derived electricity RIN generators. Finally, renewable electricity generators, OEM eRIN generators, and any other persons 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 renewable electricity generators, or of renewable electricity generators taking credit for the same volumes of renewable electricity sold to multiple OEM eRIN generators. These provisions are necessary to help prevent the generation of invalid RINs by ensuring that parties in the eRINs generation/disposition chain are informing all affected parties of issues when they arise.

2. Attest Engagements

We are proposing 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 this proposal. Specifically, we are proposing that biogas producers, RNG producers, renewable electricity generators, and OEMs 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 would be an important component of third-party oversight of the proposed eRINs program.

Under this proposal, attest engagements for biogas and RNG producers, renewable electricity generators, and OEMs would consist of an audit of underlying records, reports, and registration information (including the third-party engineering review report) for biogas production, RNG producers, renewable electricity generation, and RIN generation as applicable. These proposed attest engagements would follow the same general requirements for other attest engagements under EPA's other fuel programs. For example, an independent auditor (*i.e.,* a CPA without any interest in the audited party) would 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.

We believe attest engagements are appropriate for parties involved in the generation of eRINs as they would serve to maintain consistency across the three regulated parties and serve as valuable third-party oversight. We seek comment on requiring attest engagements for biogas and RNG producers, renewable electricity generators, and OEMs involved in the proposed eRINs program.

P. Foreign Producers

Under the RFS program, RINs may be generated for foreign-produced renewable fuels that are imported for use in the covered location either by RIN-generating foreign producers or by the importers of the renewable fuel. Currently, we have registered several landfills in Canada that produce biogas that is upgraded to RNG and injected onto the commercial pipeline system. This Canadian RNG is compressed to make renewable CNG/LNG that is used as transportation fuel in the covered location, and domestic RIN generators generate RINs for the Canadian RNG after the they have demonstrated that the RNG was used as transportation fuel in the form of renewable CNG/LNG. We are proposing similar provisions for eRINs. In the case of eRINs, we are proposing that OEMs would be able to generate eRINs for foreign-generated renewable electricity and domestic-generated renewable electricity produced from foreign-produced RNG.

1. Foreign-Produced RNG to Renewable Electricity

We are proposing to allow for the use of foreign-produced biogas to produce renewable electricity that could in turn be used to generate eRINs if an OEM could demonstrate that the renewable electricity was used as transportation fuel in the contiguous U.S. Foreign produced biogas would be eligible to participate in the eRIN program so long as it is produced consistent with an approved pathway and applicable requirements and either upgraded to RNG and injected onto a commercial pipeline system that serves the covered location, or is used to produce renewable electricity at a renewable electricity generation facility (either domestic or foreign) that transmits electricity into the commercial electric grid serving the conterminous U.S.

A foreign RNG producer would have the flexibility of either being a RIN-generating foreign producer or having the importer of the RNG generate a RIN for the RNG. This is the same flexibility that we currently provide other

imported renewable fuels, and we believe the same approach is appropriate for RNG. If the foreign RNG producer chooses to generate RINs, the foreign RNG producer would have to meet all the additional requirements applicable to RIN-generating foreign producers described in 40 CFR 80.1466, which include committing the RIN-generating foreign producer to U.S. jurisdiction and the posting of a bond commensurate with the number of RINs generated. We note that in the case where a foreign party takes title to an assigned RNG RIN, under the current regulations that party would have to comply with the additional requirements for foreign RIN owners specified at 40 CFR 80.1467. These additional requirements for foreign RIN owners include similar commitments to those we impose on RIN-generating foreign producers, and we are not proposing to modify these requirements.

In the case where the RNG importer generates the RINs for imported RNG, the importer would have to meet all applicable requirements for the generation of RINs from an imported renewable fuel under 40 CFR 80.1426. In both cases, as discussed in more detail in Section IX.I, the RIN generated for the foreign produced RNG would need to be assigned to the specific volume of RNG injected onto the commercial pipeline system and would need to be separated and retired by the renewable electricity generator when the RNG was used to produce renewable electricity.

2. Foreign-Generated Renewable Electricity

We are proposing to allow for the inclusion of foreign-generated renewable electricity for the generation of eRINs. Under this proposal, the foreign-generated renewable electricity would have to be transmitted on the commercial electric grid serving the contiguous U.S. We believe the same principles discussed in Section VIII.E.3.a that make it appropriate to assume that renewable electricity transmitted via the commercial electric grid serving the contiguous U.S. is used as transportation fuel within the U.S. would also apply if the electricity is transmitted on the same grid but is generated in Canada or Mexico.

Foreign electricity generators and foreign biogas producers would have to meet the same proposed regulatory requirements that domestic biogas producers and renewable electricity generators would have to meet. We are also proposing that in order to have eRINs generated for the foreign-produced renewable electricity, the foreign renewable electricity generator and the foreign biogas producer that supplied the biogas would have to meet the additional requirements for foreign renewable fuel producers at 40 CFR 80.1466. This approach is identical to the treatment of non-RIN generating foreign producers under the existing program for imported liquid renewable fuels.

3. Foreign OEMs

Under this proposal, similar to the treatment of foreign renewable fuel producers, OEMs that are based outside of the U.S. could either register as a foreign RIN generator or register a domestic subsidiary as the eRIN generator for their continental U.S. light-duty EV fleet. If the OEM registers as a foreign RIN generator, the OEM would have to comply with the applicable requirements for RIN-generating foreign renewable fuel producers. For foreign OEMs, this would include posting a bond for the amount of eRINs they generate and committing to U.S. jurisdiction for purposes of compliance with the RFS program requirements and enforcement. These requirements are necessary to ensure that EPA is able to enforce against the foreign OEM in the event that the OEM generates invalid RINs or otherwise fails to meet requirements under the RFS program.

If the foreign OEM registers a domestic subsidiary to be the eRIN generator, the domestic subsidiary would not need to post a bond or commit to U.S. jurisdiction. We note, that due to the parent company liability provision at 40 CFR 80.1461, the foreign parent OEM company would still be subject to liability for violations of the RFS regulations. We seek comment on this approach.

IX. Other Changes to Regulations

A. RFS Third-Party Oversight Enhancement

Independent third-party auditors and professional engineers play critical roles in ensuring the integrity of the RFS program. The independent third-party professional 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. Given EPA's recent promulgation of a program allowing renewable fuel to be produced from biointermediates,[304] we expect there will be an expansion in the scope and number of regulated entities under the RFS program, 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) rule; [305] however, those proposed changes were not finalized. We are now re-proposing (*i.e.,* proposing anew) some, but not all of those changes in order to receive further comment and public input. Given the length of time since the 2016 proposal, we believe that the proposed changes would benefit from a review of implementation of the program in the intervening years and from renewed consideration by the public. Any comments that were previously submitted on the 2016 REGS rulemaking must be resubmitted to the docket for this action. We will not consider any comments submitted on the 2016 rulemaking that are not resubmitted in response to this re-proposal.

As we explained in 2016, the 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 professional engineers may not be mitigating unlawful and fraudulent activities in the RFS program to the extent needed for a successful program, we are proposing to strengthen requirements that apply to these entities. Specifically, we are proposing to modify the requirements for the independent third-party auditors that use approved QAPs to audit renewable fuel production to verify that RINs were validly generated by the producer. The purpose of these modifications would be to strengthen the independence requirements for QAP providers that protect against conflicts of interest. We are also proposing 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 registration, including updates.

The changes to the regulations that we are proposing to make fall into six areas. First, we are proposing to strengthen the

[304] 87 FR 39600 (July 1, 2022).

[305] 81 FR 80828 (November 16, 2016).

independence requirements for third-party professional engineers by requiring those engineers to comply with similar requirements, including the additional requirements we are proposing, to those that currently apply to independent third-party auditors.

Second, we are proposing 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. Currently, the third-party engineer signs 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 proposing that third-party professional engineers provide documents and more detailed engineering review write-ups that demonstrate the professional engineer performed the required site visit and independently verified the information through the site visit and independent calculations.

Fourth, we are proposing that the required three-year engineering review updates are conducted by a third-party engineer while the facility being reviewed is operating to produce renewable fuel. We believe that the efficacy of a third-party engineer's review of a facility 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 would 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 proposing that a third-party engineer employed by an independent third-party auditor who is involved in a specified activity performed by the auditor could not be employed by the regulated party, currently or previously, within 12 months from when the regulated party hired the independent third-party to provide the specified activities. We received comments to the REGS proposed rule that due to a limited number of RFS experts to perform both engineering and auditing activities, a prohibition on providing ''cross services'' between third parties would be unworkable. Instead, we are proposing in this rulemaking a narrower and shorter limitation on third parties, consistent with other EPA programs such as the conventional fuels program, to help ensure independence between third parties and regulated parties.

Sixth, we are proposing prohibited acts and liability provisions applicable to third-party professional engineers to reduce the potential of a conflict of interest with the renewable fuel producer. The purpose of these requirements would be to help the 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 professional engineers maintain a proper level of independence from the renewable fuel producer.

Taken together, we believe these six proposed requirements would help avoid RIN fraud by strengthening third-party verification of renewable fuel producers' registration information. Additional information on third-party auditors and professional 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 proposing language that clarifies the current prohibition against an appearance of a conflict of interest to include:

- Acting impartially when performing all auditing activities.
- Disallowing a person employed by an independent third-party auditor who is involved in a specified activity performed by the auditor to be employed by the regulated party, currently or previously, within 12 months from when the regulated party hired the independent third-party to provide the specified activities.

These provisions would be intended to prevent third-party auditors from seeking or obtaining employment from producers for which the auditors are 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. With regard to companies that employ personnel who previously worked for or otherwise engaged in consulting services with a producer, those companies would meet the independence criteria when such personnel do not participate on, manage, or advise the audit teams. Additionally, employees of these companies would not be prohibited from accepting future employment with a producer as long as they were not involved in performing or managing the audit.

In the RFS QAP final rule, we stated that we continued to be concerned that allowing an auditor to also perform engineering reviews and attest engagements would tie the auditor's financial interests too closely with the renewable fuel producer being audited and could create incentives for auditors to fail to report potentially invalid RINs.[306] However, we did not want to exclude potential third-party auditors that had significant knowledge of the RFS program and renewable fuel production facilities from participating in the QAP program. Therefore, the final rule prohibited third-party auditors from continuing to provide annual attest engagements and QAP implementation to the same audited renewable fuel producer but allowed third-party auditors to continue to conduct engineering reviews. We received significant comments to the REGS proposed rule that proposed to preclude third parties from performing engineering reviews and providing QAP services to the same producers. As a result, we are not re-proposing this prohibition.

2. Third-Party Professional Engineers

Engineering reviews from independent third-party professional 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 professional engineers, affiliates, and renewable fuel producers are analogous to third-party auditors and renewable fuel producers. As a result, we are proposing to strengthen the independence requirements for third-party professional engineers by requiring those engineers to comply with similar requirements (including the additional requirements we are

[306] 79 FR 42078 (July 18, 2014).

proposing) to those that currently apply to independent third-party auditors.

We are also proposing to improve the RFS registration requirements for three-year engineering review updates by requiring site visits to take place when the facility is producing renewable fuel. Comments received to this requirement in the REGS proposed rule noted that a facility would be required to generate fuel but not RINs if EPA required the engineering review site visit for a facility's initial registration. However, by the three-year engineering review, facilities should reasonably be able to coordinate with third-party engineers to ensure they are operational for the engineering review. This would provide the regulated community and the 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 professional engineers. Some of these engineers are using templates that make it difficult for the 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 proposing that the engineering review submission include evidence of a site visit while the facility is producing renewable fuel(s) that it is registered to produce. We also propose to incorporate the 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 would 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 also propose to require the third-party engineer to electronically certify that the third-party meets the independence requirements whenever the third-party submits engineering reviews or engineering review updates to EPA. Currently, the third-party engineer signs 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 would help provide greater assurance that third-party professional 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 proposing prohibited activities for third-party professionals failing to properly conduct an engineering review, or failing to disclose to the EPA any financial, professional, business, or other interest with parties for whom the third-party professional engineer provides services for under the RFS registration requirements. The EPA staff that review RFS registrations have concerns that third-party professional engineers may be acting, independently or through an affiliate, as consultants and agents for the same renewable fuel producer, or that, directly or through an affiliate, they may have a financial interest in the renewable fuel producer, may not appropriately conduct engineering reviews, or may not meet the requirements for independence to qualify as a third-party. We believe that making third-party professional engineers more accountable for properly conducting engineering reviews under the regulations and requiring that they interact more directly with the EPA would help our ability to identify potential conflicts of interests and bring enforcement actions against third-party professional engineers should an issue arise.

B. Deadline for Third-Party Engineering Reviews for Three-Year Updates

We are proposing to require 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. Under the existing regulations, renewable fuel producers are required to have a third-party engineer conduct an updated engineering review three years after initial registration. The regulations state that the three-year engineering review reports are due by January 31 after the first year of registration. However, the regulations do not specify when the third-party engineer has to conduct the site visit. We have received several inquiries by 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 noted 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.

We now 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 proposing that the site visit occur no sooner than July 1 of the preceding calendar year. We believe that this amount of time would 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 note that this seven-month period would be greater than the originally provided 120-day period under prior EPA guidance. We believe more time is warranted as the number of facilities that require three-year updates has increased. We seek comment on this proposed deadline and whether more or less time is warranted to balance the efficacy of the third-party site visit with ensuring enough time for renewal fuel producers to satisfy their three-year registration update requirements.

We are also proposing to specify which batches of RINs should be included in the V_{RIN} calculation portion of the three-year registration update. Under this proposal, 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 appropriate 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 vary significantly across third-party engineers and we want to ensure that this portion of the engineering review update is conducted consistently. We seek comment on this proposed change.

C. RIN Apportionment in Anaerobic Digesters

In the Pathways II rule, we updated RIN-generating pathways using biogas as a feedstock to allow D3 RINs to be generated for renewable compressed natural gas (CNG) and renewable liquefied natural gas (LNG) produced from biogas from digester types that

process only predominately cellulosic[307] 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.[308] We also created a renewable CNG/LNG pathway to allow for D5 RINs to be generated for biogas produced from other waste digesters;[309] this pathway must be used if the feedstock being processed in a digester is not predominantly cellulosic. If a party wishes to simultaneously convert 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, the regulations at 40 CFR 80.1450(b)(1)(xiii)(B) requires parties to calculate and submit to EPA as part of their registration materials the cellulosic converted fraction, *i.e.,* the portion of a cellulosic feedstock that is converted into renewable fuel. The cellulosic converted fraction calculation is based on measurements of cellulose, and these measurements must be obtained using a method that would produce 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, with any degree of accuracy, the cellulosic content of the feedstock at the time of registration.

Since the Pathways II rule was finalized, we have had numerous inquiries from stakeholders about 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.[310] This processing condition is desirable for stakeholders because simultaneous conversion in a single digester can lead to higher biogas yields than processing in separate digesters[311] with less capital investment. Some stakeholders have asked whether EPA would consider the separated food waste in these instances to be a predominantly cellulosic feedstock, which would allow producers to obtain D3 RINs for all biogas produced from the digester. However, in the Pathways II rule, we did not find that separated food waste necessarily meets the predominantly cellulosic criteria,[312] and we continue to believe it generally does not have an adjusted cellulosic content greater than 75 percent. Therefore, biogas-derived renewable fuels produced from biogas produced from mixed feedstocks that include separated food waste are not eligible to generate 100 percent D3 RINs and are subject to the registration requirements in 40 CFR 80.1450(b)(1)(xiii)(B), which includes testing to determine the cellulosic content of the feedstocks. Other inquiries have sought clarification about whether it is possible to apportion the predominantly cellulosic feedstock as D3 and the separated food waste as D5 without needing to test the cellulosic composition of individual or mixed feedstocks. Proposed solutions by stakeholders focused on determining the cellulosic biogas converted fraction from processing just the predominantly cellulosic feedstock, for example by assuming that the predominantly cellulosic feedstock produces the same amount of methane when it is processed alone (based on a biochemical methane potential test) as when it is processed in an anaerobic digester with other feedstocks. However, this approach is not allowed under the existing regulations in 40 CFR 80.1450(b)(1)(xiii)(B)(3), since the existing regulations require the cellulosic converted fraction to be based on chemical testing for cellulosic content, without any allowance for testing predominantly cellulosic feedstocks separately in lieu of chemical testing of cellulosic content. However, even if such chemical testing was undergone for registration, we believe the existing approach in the regulations may not be acceptable due to the variability of the food waste feedstock composition which makes it likely that any converted fraction submitted for the purpose of registration is not representative of the actual composition of the feedstock used to produce biogas. This lack of accuracy could lead to cellulosic RINs being generated on non-cellulosic feedstocks.

EPA's existing 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. Currently, these requirements apply to all situations in which predominantly cellulosic[313] and non-cellulosic feedstocks are simultaneously converted to produce a single type of fuel.[314] 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 case of feedstocks co-processed in a digester, we have determined that a number of the existing requirements are unnecessary or otherwise inappropriate. For example, chemical data showing the cellulosic content of the mixed feedstocks is not necessary because the feedstocks can be measured separately before they are mixed (and measurement may not be needed if the separate feedstocks have already been determined to be predominantly cellulosic or non-cellulosic). Additionally, the regulatory apportionment equations use dry mass, which is less accurate for biogas than volatile solids, which is the value typically used in the digester industry.[315] The apportionment equations also include an energy component, which, as noted by a commenter in a previous rulemaking, can underweight biogas from feedstocks with lower energy content.[316] Finally, even if cellulosic testing were conducted on select batches of feedstock, the highly heterogeneous composition of separated food waste raises the likelihood that sampling would not be representative, which could cause D3 RINs to be generated when the fuel is not derived from cellulosic biomass.

At the same time, there are also features of co-processing in a digester

[307] A predominately cellulosic feedstock is a feedstock with an adjusted cellulosic content, as defined in 40 CFR 80.1401, of greater than 75 percent.

[308] EPA's regulations also allow D3 RINS to be generated for renewable CNG/LNG produced from biogas from landfills.

[309] See Table 1 to 40 CFR 80.1426; 79 FR 42168 (July 18, 2014).

[310] 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.

[311] Karki et al. Bioresource Technology 330 (2021) 125001. DOI: 10.1016/j.biortech.2021.125001.

[312] 79 FR 42140 (July 18, 2014).

[313] For feedstocks that have been determined to be predominantly cellulosic, see 79 FR 42140 (July 18, 2014).

[314] 40 CFR 80.1426(f)(3)(vi).

[315] Dry mass, also referred to as total solids in the digester industry, includes ash, which consists of salts that are is left over after combusting the total solids. Due to the lack of organic matter, ash is generally considered to not contribute to methane production. The volatile solids term excludes the ash content, so it is generally regarded as a more accurate measure of the substance that is capable of producing methane.

[316] See comment submitted by Fulcrum BioEnergy, Inc., Docket Item No. EPA–HQ–OAR–2021–0324–0434.

that make it reasonable to consider a different regulatory approach to RIN apportionment. The feedstocks in question are generated as physically separate streams, so that mass, moisture content, and methane production potential of each feedstock can be determined before mixing. This possibility of measuring physically separated feedstocks individually is not contemplated by the current 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 in the food waste, which means that chemical analysis of the cellulosic content of the food waste feedstock and digestate is not required. In addition to the feedstocks being physically separate, mixing of typical feedstocks in anaerobic digestion does not lead to a decrease in biogas production relative to when they are processed together, reducing the risk of D3 RINs being generated from non-cellulosic feedstock.[317]

Based on the differences discussed above, we are proposing new and separate equations to determine feedstock energy for when predominantly cellulosic and non-predominantly cellulosic feedstocks are simultaneously converted in anaerobic digesters. The cellulosic feedstock energy equation is similar to the equation in 40 CFR 80.1426(f)(3)(vi), with a few modifications. The proposed equation uses a volatile solids measurement since non-volatile solids do not generally produce biogas, making this equation more accurate than the one in 40 CFR 80.1426(f)(3)(vi). We are also specifying that the feedstock energy used in the equation should be the energy content of biogas instead of the feedstock to avoid disproportionate RIN generation for higher energy feedstock and so that the equation that results is the energy content of the biogas which is used as the feedstock to the renewable fuel pathway. The non-predominantly cellulosic feedstock energy equation sets the non-predominantly cellulosic feedstock energy to be the difference between total biogas produced and cellulosic biogas as calculated by the cellulosic feedstock apportionment equation. We believe these updated equations would 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 proposing biogas producers keep records of feedstocks necessary to recompute apportionment calculations.

To support this proposed apportionment, we are proposing separate registration requirements to determine the converted fraction of the predominantly cellulosic feedstock used in an anerobic digester when it is simultaneously converted with a non-predominantly cellulosic feedstock. Instead of chemical data supporting a cellulosic converted fraction as required under the existing regulations, we are proposing that a facility producing biogas from anaerobic digestion be required at registration to 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;
- A description including any calculations demonstrating how the data were used to determine the cellulosic converted fraction; and
- The cellulosic converted fraction that will be used in the RIN apportionment.

Operational data used to determine the cellulosic converted fraction would 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 proposing a requirement that the registrant identify the conditions in its registration under which the facility would need to operate to properly apportion RINs. In specifying those processing conditions, we are proposing a requirement that parties 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 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.

We are not proposing to require registrants to submit data on whether their converted fraction determined from processing a single feedstock applies when processing multiple feedstocks because evidence from literature shows that cellulosic converted fractions generally do not decrease, and in some cases increase, when adding additional feedstocks such as food waste under identical processing conditions.[318] Our approach thus conservatively assumes that the cellulosic converted fraction is the same when processing a single feedstock and multiple feedstocks, which we believe would result in digester operators using a conservative estimate of the biogas produced from cellulosic feedstock when simultaneously processing it with non-cellulosic feedstock. The evidence from literature allows us to simplify the registration process while still providing us with the assurance that RINs are generated with the appropriate D-code.

Instead of providing operational data, we are also proposing to allow registrants an alternative 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 proposing 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.[319] 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,

[317] Karki et al. Bioresource Technology 330 (2021) 125001. DOI: 10.1016/j.biortech.2021.125001.

[318] Karki et al. Bioresource Technology 330 (2021) 125001. DOI: 10.1016/j.biortech.2021.125001.

[319] 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.

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.[320] Given the limited types of feedstocks, the limited number of digesters evaluated in this study, and the different goals behind the recommendations,[321] 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.[322] We welcome comments suggesting other default values of converted fractions based on other data sources, such as operational data. Comments presenting alternative converted fraction values should also contain information about the underlying data, discussion of why the underlying data is representative (for example, by describing the process by which data was selected) and how the converted fraction was derived from operational data, and a list of operational conditions on which the data was based.

We are proposing that the requirements discussed in this subsection only apply for processes using biogas from anaerobic digestion that simultaneously convert multiple feedstocks where at least one is not predominantly cellulosic. We are seeking comment on whether the proposed approach should be more limited, for example, to digesters processing separated food waste, or whether some aspects of these proposed changes could be applied more broadly, for example, to all simultaneous conversion of renewable feedstocks where one or more does not meet the minimum 75 percent cellulosic content requirement and when the feedstocks are produced separately and can be separately measured. Commenters should provide examples of how expanding or restricting the use of these proposed changes beyond pathways for the production of renewable CNG/LNG or renewable electricity from biogas produced in anaerobic digesters would be beneficial or problematic, using examples of specific production pathways and processes.

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 as renewable electricity. We are proposing that the different D-codes be tracked through product transfer documents from biogas producers, RNG producers, and renewable electricity generators as well as reporting of D-code information into EMTS. Under this proposed approach, biogas producers would 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.I) and renewable electricity (as discussed in Section VIII) would use this proportion to calculate the appropriate number of D3 and D5 RINs.

D. BBD Conversion Factor for Percentage Standard

In the proposal for the 2020–2022 standards, we proposed a change to the conversion factor used in the calculation of applicable percentage standards for BBD.[323] We did not finalize that proposed change in the final rulemaking which established the applicable standards for 2020–2022. We are now reproposing that change for implementation for compliance years 2023 and beyond, and are including data from 2021 in the proposed 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.[324] 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.

The formula for calculating the applicable percentage standards for BBD 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 for biodiesel, 1.5, as discussed in the 2007 RFS1 final rule.[325] The resulting formula[326] (incorporating the recent modification to the definitions of GE_i and DE_i)[327] 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

[320] Holliger et al. (2017) Frontiers in Energy Research, 5, 12. DOI: 10.3389/fenrg.2017.00012.

[321] When designing a digester and gas treatment system, one would like to maximize the amount of fuel or energy and using a slight overestimate of biogas production is less of a problem than in the RFS program, where overestimating cellulosic production of biogas would lead to invalidly generated RINs.

[322] See memo ''Calculation of cellulosic converted fraction values from biochemical methane potential,'' available in the docket for this action.

[323] 86 FR 72474 (December 21, 2021).

[324] See 75 FR 14670, 14682 (March 26, 2010).

[325] See 72 FR 23900, 23921 at Table III.B.4–1 (May 1, 2007).

[326] See 40 CFR 80.1405(c).

[327] See 85 FR 7016 (February 6, 2020).

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.

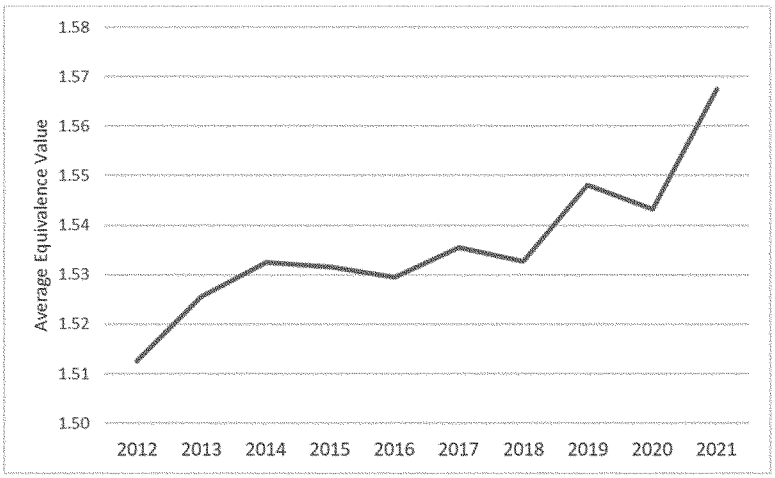
RDS_i = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

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 projected to be exempt in year i, in gallons, per §§ 80.1441 and 80.1442.

In the years following 2010 when the percent standard formula for BBD was first promulgated, advanced renewable diesel production has grown. Most renewable diesel has an Equivalence Value of 1.7, and its growing presence in the BBD pool means that the average Equivalence Value of BBD has also grown.[328]

Figure IX.D-1: Average Equivalence Value 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 2 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 Equivalence Value of BBD appears to have grown over time without stabilizing. This trend has continued and is consistent with the growth in facilities producing renewable diesel as discussed in DRIA Chapter 5.2. Based on the data shown in Figure IX.D–1, we believe that the factor used in the formula for calculating the percentage standard for BBD should be at least 1.57. We are therefore proposing to replace the factor of 1.5 in the percentage standard formula for BBD with a factor of 1.57.[329] For the final rule, we will consider additional data that may be available and may adjust this factor as appropriate. Note that we are not proposing to change any other aspect of the percentage standard formula for BBD.

E. Flexibility for RIN Generation

We are proposing minor edits for 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 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 and if the renewable fuel producer has not met all other applicable requirements, including registration, reporting, and recordkeeping requirements.[330] Our 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 the EPA. In light of this approach, we have determined that a more straightforward approach would be to allow, rather than require, RINs to be generated for qualifying renewable fuel. Thus, we are proposing that 40 CFR 80.1426(a)(1), (a)(2) and (b) state that RINs ''may only'' be generated if certain requirements are met. We are also proposing to remove

[328] Under 40 CFR 80.1415(b)(4), renewable diesel with a lower heating value of at least 123,500 Btu/gallon is assigned an Equivalence Value of 1.7. A minority of renewable diesel has a lower heating value below 123,500 BTU/gallon and is therefore assigned an Equivalence Value of 1.5 or 1.6 based on applications submitted under 40 CFR 80.1415(c)(2).

[329] While we are proposing to revise the factor of 1.5 in the percentage standard formula for BBD, we would include 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.

[330] 40 CFR 80.1426(a)(1)(iii).

the provisions for small volume renewable fuel producers at 40 CFR 80.1426(c)(2) and (c)(3) as well as 40 CFR 80.1455 because those provisions are no longer necessary. If any renewable fuel producer, regardless of size, has the flexibility to choose to generate RINs, then there is no longer a need to provide flexibility for small producers because they would only choose to generate RINs if it were economically beneficial to do so. We seek comment on our proposal to modify the RIN generation provisions to allow rather than require RIN generation.

F. Changes to Tables in 40 CFR 80.1426

We are proposing 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).[331] As they currently exist in the CFR, these tables are 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 means that they should be located at the very end of 40 CFR 80.1426. Currently, however, Tables 1 and 2 are located after 40 CFR 80.1426(f)(1)(vi), Table 3 is located in 40 CFR 80.1426(f)(3)(v), and Table 4 is located in 40 CFR 80.1426(f)(3)(vi)(A).

In order to conform with OFR's guidelines, we are proposing to move Tables 1 and 2 to the end of 40 CFR 80.1426, consistent with their current designation. Since we are not proposing to change 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) would remain accurate and valid. In contrast, for Tables 3 and 4, we are proposing to create new provisions within the regulations into which we would move and consolidate the formulas in these tables. Specifically, we would move and consolidate the five formulas currently in Table 3 into 40 CFR 80.1426(f)(3)(v), and would move and consolidate the five formulas currently in Table 4 into 40 CFR 80.1426(f)(3)(vi)(A). The formulas themselves would effectively 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 proposed change.

We seek comment on our proposal to move Tables 1 and 2 to the end of 40 CFR 80.1426 and to retain their current designations (''Table 1 to 40 CFR 80.1426'' and ''Table 2 to 40 CFR 80.1426''), to move and consolidate the formulas currently within Tables 3 and 4 into paragraphs 40 CFR 80.1426(f)(3)(v) and (vi)(A), respectively, and on whether any additional clarification or revisions are necessary to implement these moves. We reiterate that we are not proposing to revise or otherwise reopen the contents of Table 1 or Table 2 as part of this move, or to revise or otherwise reopen the formulas that are currently in Table 3 and Table 4, other than to move and consolidate them.

G. Prohibition on RIN Generation for Fuels Not Used in the Covered Location

We are proposing amendments to 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 our implementing regulations already limit RIN generation to renewable fuel produced for use in the United States, and these amendments are intended to address any perceived confusion on the part of stakeholders. The amendments specify that RINs cannot be generated on 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 our proposal reinforces that generating RINs for fuel not produced for use in the covered location is a prohibited activity. We seek comment on our proposed amendments to reiterate that parties cannot generate RINs for renewable fuel unless it was produced for use in the covered location.

H. Seeking Public Comment on Hydrogen Fuel Lifecycle Analysis

1. Background and Purpose

EPA has received multiple petitions pursuant to 40 CFR 80.1416 requesting cellulosic biofuel (D-code 3) RIN eligibility for new fuel pathways that use renewable natural gas (RNG) produced from biogas from anaerobic digesters or landfills as a feedstock to produce hydrogen fuel for use in fuel cell electric vehicles (FCEVs). The pathway petitions received to date have focused on the use of steam methane reforming (SMR), a process that reacts natural gas or RNG with high-pressure steam to produce hydrogen fuel.[332] Approximately 95 percent of hydrogen produced in the United States today is produced using SMR. The large majority of SMR facilities use natural gas feedstock, though there are variations of this process and differences in efficiencies across facilities. Although most hydrogen fuel is currently used in industrial processes such as petroleum refining and fertilizer production, there is interest in using hydrogen as a transportation fuel in light-duty, medium- and heavy-duty, and non-road vehicles.

In this section we are presenting estimates of lifecycle GHG emissions associated with the feedstock sourcing, production, transport, and use of hydrogen fuel produced from RNG through an SMR process for use as a transportation fuel. Clean Air Act section 211(o)(1)(B) defines advanced biofuel, of which cellulosic biofuel[333] is a subset, as ''renewable fuel, other than ethanol derived from corn starch, that has lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, that are at least 50 percent less than the baseline lifecycle greenhouse gas emissions.'' Thus, for a fuel to qualify as a cellulosic or advanced biofuel and be eligible to generate D-code 3 or D-code 5 RINs respectively, the public must have notice of and an opportunity to comment on EPA's lifecycle GHG assessment of that fuel. We are therefore requesting public comment on use of the lifecycle GHG estimates in this section and related topics in support of evaluating and resolving the pathway petitions for hydrogen fuel before the agency.

The estimates summarized below are from Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET)[334] model for hydrogen fuel produced from RNG through an average SMR process. We present GREET results here since it is a publicly available data source developed by a U.S. Department

[331] Office of the Federal Register, National Archives and Records Administration, ''Document Drafting Handbook,'' August 2018 Edition (Revision 1.4), January 7, 2022.

[332] Hydrogen Production: Natural Gas Reforming. Department of Energy, *https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.*

[333] Cellulosic biofuel is defined in Clean Air Act section 211(o)(1)(E) as ''renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.''

[334] Argonne Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model, *https://greet.es.anl.gov.*

of Energy laboratory that are similar to the pathway petitions EPA has received. EPA has often used GREET as one of the data sources for our lifecycle analysis assumptions in the past. The predeveloped pathways in GREET were similar in scope to the petitions that were submitted to EPA under claims of confidential business information, therefore presenting the GREET data allows for public comment without disclosing data that was claimed as confidential business information.

Based on the data and information we have received from petitioners to date, the lifecycle GHG emissions associated with hydrogen produced from RNG via SMR vary significantly based on the configuration of individual hydrogen production facilities and how hydrogen from individual facilities gets distributed to end users. While SMR production of hydrogen is well established, hydrogen use as a transportation fuel introduces new areas of significant variation and uncertainty that would be more difficult to address in a generalized lifecycle GHG analysis of hydrogen fuel (*e.g.,* whether hydrogen fuel is produced on-site or at larger centralized SMR facilities, or whether hydrogen fuel is compressed or liquified). Given these variations in a relatively nascent transportation fuel market and the lack of real-world data, we believe it is prudent as a first step towards approving hydrogen fuel pathways to take into account the GHG emissions associated with a specific facility's production and distribution of hydrogen fuel at this time. EPA's evaluation of individual petitions will be based on the petitioner's energy and mass balance data and, as we are requesting comment on here, the GHG emissions associated with the petitioners' fuel production processes and combined with data from GREET on emissions upstream from biogas sourcing as well as downstream associated with the distribution and use of the finished biofuel. Our intent is to use this combination of GREET data and pathway petition data to determine whether the fuel produced at an individual facility satisfies the CAA renewable fuel GHG reduction requirements. Due to the large number of possible configurations for producing transportation fuel from hydrogen, and varying energy requirements for producing gaseous and liquid hydrogen, we do not intend to promulgate a generally applicable pathway for hydrogen fuel to Table 1 to 40 CFR 80.1426 at this time.[335]

In this section, we also discuss and seek comment on key and novel aspects of using hydrogen fuel under the RFS program, including compression and pre-cooling of the hydrogen fuel, hydrogen fuel cell electric vehicle efficiency, and the global warming potential of fugitive hydrogen. We request comment on these topics, as they all have a potential impact on the lifecycle GHG emissions.

There are additional considerations beyond the lifecycle GHG emissions that may need to be resolved before RINs can be generated for hydrogen. These include registration, recordkeeping, and reporting requirements, product transfer documents, the party that would generate the RINs, the equivalence value that determines the number of RINs generated for a given quantity of hydrogen, and the definition of ''produced from renewable biomass'' that is discussed in Section IX.M. Following the notice and opportunity for public comment provided here, we believe we would be in a position to act on facility-specific hydrogen fuel pathway petitions submitted pursuant to 40 CFR 80.1416, in situations where no additional regulatory changes are needed to accommodate the generation of RINs for hydrogen fuel.

2. Hydrogen Fuel Steam Methane Reforming (SMR) Lifecycle Analysis

Evaluation of the lifecycle GHG emissions associated with hydrogen fuel under the RFS program must consider ''the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer,'' not merely the hydrogen fuel production step.[336]

In this analysis, we are considering hydrogen fuel produced in an SMR from RNG sourced from landfill biogas. The feedstock is biogas from landfills which we have previously evaluated as part of the RFS2 final rule lifecycle determination.[337] Therefore no new renewable feedstock production modeling is required. No direct or indirect land use change emissions were attributed to landfill biogas as a feedstock. Landfill biogas is a natural byproduct of the decomposition of organic material in landfills. It is composed of roughly 50 percent methane (the primary component of natural gas), 50 percent carbon dioxide (CO_2), and a small amount of non-methane organic compounds.[338] The landfill biogas is captured and upgraded to RNG to increase the concentration of methane and remove CO_2 along with other impurities. The upgraded pipeline specification RNG is then injected into a common carrier pipeline to transport the gas that is functionally identical to fossil natural gas towards facilities that can use the feedstock. In this case the pipeline transports the RNG to an SMR located offsite in order to produce hydrogen fuel.

While we describe a few variations of SMR processes below, consisting of different sizes, production capacities, and primary energy sources, these all share similarities in that they convert the RNG into hydrogen by subjecting it to high pressure and temperatures in the presence of a catalyst using energy supplied to the system to release and bond the embedded hydrogen molecules together found in the RNG and supplied water.[339] This two-step process includes the namesake steam-methane reforming reaction and a subsequent water-gas shift reaction that releases additional hydrogen from the water in the process. This process relies on RNG, fossil natural gas, or electricity to supply the energy for the steam methane reforming-with the most common energy source being fossil natural gas for larger and more centralized facilities. Natural gas or RNG can be used in SMRs for both the feedstock and also as the process energy to drive the reactions. While some of the hydrogen molecules are stripped from water in the process, there is no energy in the finished fuel that originates from the water molecules. The energy in the finished hydrogen fuel comes from both the feedstock and process energy used as inputs to the SMR, which relates to the ''produced from renewable biomass'' topic as discussed in Section IX.M.

[335] We anticipate that some refineries would wish to use hydrogen produced from RNG via SMR as a feedstock for producing other renewable fuels. We intend for the lifecycle GHG analysis for hydrogen in Section 9.H.2 to inform the broader evaluation of such renewable fuels produced at refineries.

[336] Clean Air Act section 211(o)(1)(H).

[337] March 2010 RFS2 rule (75 FR 14670).

[338] EPA Landfill Methane Outreach Program (LMOP), Basic Information about Landfill Gas, *https://www.epa.gov/lmop/basic-information-about-landfill-gas.*

[339] Hydrogen Production: Natural Gas Reforming, Department of Energy, Hydrogen and Fuel Cell Technologies Office, *https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.*

Once hydrogen fuel is produced in the SMR, it must be specially stored and transported for its end use as a transportation fuel. Hydrogen fuel differs from conventional liquid fuels due to the significant amount of energy required for concentration, transportation, and storage of the fuel. While hydrogen fuel is typically produced in a gaseous form, it requires compression at high pressure to maintain a reasonable storage or transportation volume and requires significant energy to perform that compression. Liquefaction of the hydrogen fuel to below −423 degrees Fahrenheit is another option for further reducing the volume and allowing for easier transportation of greater amounts of hydrogen fuel over long distances using cryogenic tanker trucks compared to gaseous tube trailers, but this comes at an even greater energy cost than gaseous hydrogen fuel compression.[340] Once delivered to a refueling station, hydrogen fuel is commonly gasified and pre-cooled to enable faster refueling of vehicles. These steps require energy, usually from electrically driven compressors. Argonne's GREET evaluates both the centralized and distributed [341] hydrogen fuel production and distribution scenarios.

The GREET model contains various pathway analyses for hydrogen produced through an SMR process. We present the following lifecycle estimates based on results from GREET that represent average hydrogen production scenarios using landfill biogas as the feedstock based on data from industry average SMR facilities. The steps include feedstock production, feedstock transportation, hydrogen fuel production, transportation of the finished fuel, and dispensing to vehicles at a hydrogen refueling station. We present three different scenarios below from GREET that most closely represent the various pathway petitions using an SMR that the agency has received. Facility specific GHG estimates would vary slightly from these GREET pathways based on factors such as process efficiency, energy inputs, and transport distances, among others.

All scenarios assume the feedstock is RNG sourced from landfill biogas.[342] GREET assumes electricity is used to upgrade and process the landfill biogas and approximately two percent of the methane is assumed to become fugitive during this process. The resulting upgraded RNG is compressed and injected into a common carrier natural gas pipeline for transportation to the SMR facility to be converted to hydrogen fuel.

The first two scenarios presented below represent lifecycle GHG emissions for large centralized SMR facilities that are meant to produce hydrogen in one location and transport it to hydrogen refueling stations for end-users, similar in concept to how petroleum refineries produce gasoline and transport the resulting fuel to gas stations. The first scenario represents gasifying the hydrogen fuel and the second scenario represents liquefaction of the hydrogen fuel, which as described above incurs a greater energy and GHG emissions burden compared to gasification. In both scenarios, the SMR process is assumed to use fossil natural gas for converting the RNG feedstock into hydrogen fuel and export excess steam for other industrial processes. GREET assumes natural gas as the energy input into the process. Therefore, when considering the SMR system as a whole, 59.4 percent of the energy comes from RNG as the feedstock and 40.6 percent of the energy comes from the fossil natural gas used to drive the process. The system has an overall average energy efficiency ratio of 71.9 percent, meaning it takes approximately 1.4 million Btu (mmBtu) of total natural gas (RNG and fossil natural gas) to produce 1.0 mmBtu of hydrogen fuel.

For compression and pre-cooling of hydrogen in all scenarios, the energy source is assumed to be electricity from the average U.S. electrical grid. Table IX.H.2–1 provides examples of the amount of electricity that GREET assumes for various steps of the finished hydrogen fuel transportation, delivery, and vehicle fueling process. We recognize that these values can vary based on factors such as fuel volumes delivered, transportation distance, and residence time of the hydrogen fuel that requires cooling, among others. The hydrogen fuel is assumed to be used in hydrogen fuel cell electric vehicles and therefore has no associated tailpipe GHG emissions.

TABLE IX.H.2–1—ELECTRICITY REQUIRED FOR HYDROGEN FUEL COMPRESSION AND PRE-COOLING FROM GREET 2021

[kWh/kg H_2]

	Compressor to load gaseous tube-trailer for H_2 delivery	H_2 compressor at vehicle refueling station	Pre-cool H_2 for vehicle refueling
Centralized Gaseous Hydrogen Fuel Production:			
Light-Duty FCEVs (700 bar H_2) [343]	1.30	1.98	0.30
Medium- and Heavy-Duty FCEVs (350 bar H_2)	.....	1.25	.....
Distributed Hydrogen Fuel Production:			
Light-Duty FCEVs (700 bar H_2)	N/A	3.11	0.30
Medium- and Heavy-Duty FCEVs (350 bar H_2)	.....	2.27	.....

[340] Liquid Hydrogen Delivery. Department of Energy, *https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery.*

[341] Centralized production refers to producing hydrogen fuel from larger facilities that can increase production efficiency but requires distribution through a network of gaseous or liquified hydrogen tube trailer or pipeline deliveries to hydrogen refueling stations. Distributed hydrogen fuel production refers to producing hydrogen fuel at the point of end-use such as at the refueling stations themselves. This is generally expected to have lower production efficiencies and requires the hydrogen fuel production inputs (*e.g.,* natural gas, electricity, water) to come to the distributed hydrogen fuel production site but eliminates the need to transport the finished hydrogen fuel to a separate location.

[342] While GREET's assumptions here use landfill biogas, EPA stated in the RFS Pathways II and Technical Amendments to the RFS 2 Standards final rule (79 FR 42128) that GHG lifecycle emissions for biogas generated at MSW landfills reasonably represent biogas from municipal wastewater treatment facility digesters, agricultural digesters, separated MSW digesters, and waste digesters as well. We would therefore use this proposed lifecycle assessment to represent any of those feedstocks as they have already been evaluated and approved in Table 1 to 40 CFR 80.1426. Biogas from waste digesters that does not meet the regulatory criteria as cellulosic feedstock used to generate hydrogen fuel would only be able to qualify for advanced (D5) or conventional biofuel (D6) RINs.

[343] Hydrogen fuel needs to be compressed to high pressures to reduce its volume for onboard storage tanks in vehicles. As light-duty vehicles are more space limited, they typically refill using gaseous hydrogen fuel compressed to 700 bar or approximately 10,000 psi. Heavy-duty vehicles can carry larger tanks and typically refill using hydrogen fuel compressed to 350 bar or approximately 5,000 psi. More energy is needed to achieve higher levels of compression.

In addition to the GREET default assumptions supported by industry data, we also present GREET results that make use of assumptions from NREL's Hydrogen Analysis (H2A) model in the table below. NREL assumes a similar 72.0 percent conversion efficiency for centralized steam methane reforming. H2A also assumes that a small percentage (approximately 1.2 percent) of the total energy to produce the hydrogen in centralized SMR comes from grid electricity, unlike the default GREET assumptions. We present both the default GREET results and those from GREET using NREL H2A assumptions in Table IX.H.2–2 below to show a range of values from the model.

TABLE IX.H.2–2—LIFECYCLE GHG EMISSIONS FOR PRODUCING GASEOUS AND LIQUID HYDROGEN FROM CENTRALIZED STEAM METHANE REFORMING (SMR) USING LANDFILL GAS AS FEEDSTOCK AND NATURAL GAS AS THE PREDOMINANT PROCESS ENERGY SOURCE

[$kgCO_2e$/mmBtu] [344]

	Gaseous hydrogen fuel		Liquid hydrogen fuel	
	GREET default assumptions	GREET using NREL H2A assumptions	GREET default assumptions	GREET using NREL H2A assumptions
Domestic & International Land Use Change	0.0	0.0	0.0	0.0
Feedstock Production & Transport	9.2	9.2	10.0	10.0
Fuel Production	11.4	25.8	39.0	53.6
Tailpipe	0.0	0.0	0.0	0.0
Lifecycle GHG Emissions	20.5	34.9	49.0	63.5

The third scenario shown below in Table IX.H.2–3 represents lifecycle GHG emissions for producing gaseous hydrogen fuel using a smaller-scale SMR for distribution directly at a refueling station (also referred to as distributed production or forecourt natural gas reforming). This configuration would be analogous to a gas station that produces its own gasoline onsite. This scenario still assumes the feedstock is renewable natural gas sourced from landfill biogas and it arrives at the distributed SMR via natural gas pipeline. The SMR process is assumed to use a mixture of grid-based electricity and fossil natural gas for converting the RNG feedstock into hydrogen fuel. GREET assumes the system has an overall average efficiency ratio of 74.2 percent while NREL's H2A model assumes the process is 71.4 percent efficient. The gaseous hydrogen is compressed and pre-cooled to allow for fast vehicle refueling, using electricity from average U.S. electrical grid as the energy source. As with the other scenarios, the hydrogen fuel is assumed to be used in hydrogen fuel cell electric vehicles and results in no tailpipe GHG emissions.

TABLE IX.H.2–3—LIFECYCLE GHG EMISSIONS FOR PRODUCING GASEOUS HYDROGEN FROM DISTRIBUTED STEAM METHANE REFORMING (SMR) USING LANDFILL GAS AS FEEDSTOCK AND NATURAL GAS AND GRID ELECTRICITY AS THE PROCESS ENERGY SOURCES

[$kgCO_2e$/mmBtu] [345]

	Gaseous hydrogen fuel	
	GREET default assumptions	GREET using NREL H2A assumptions
Domestic & International Land Use Change	0.0	0.0
Feedstock Production & Transport	12.2	12.2
Fuel Production	18.5	20.1
Tailpipe	0.0	0.0
Lifecycle GHG Emissions	30.7	32.3

We request comment on the lifecycle GHG estimates presented for hydrogen fuel produced from an SMR process based on information from the GREET model. We also invite comment on our intent to combine GREET data with information from pathway petitions submitted pursuant to 40 CFR 80.1416, with adjustments to account for aspects of each facility and how they plan to distribute hydrogen to end users. This would allow us to determine whether proposed pathways satisfy CAA lifecycle GHG emission reduction requirements for RFS-qualifying renewable fuels on a facility-specific basis. Based on the data presented here, hydrogen fuel produced from RNG in an SMR may qualify for either advanced (D-code 5) RINs or cellulosic (D-code 3) RINs when compared against the

[344] Results are presented from Argonne Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model where the model is set to use landfill gas as the source of natural gas for methane feedstock in the SMR process. GREET's default assumptions represent process energy to be 100 percent natural gas. To review the complete spreadsheet assumptions, see ''GREET1_2021rev1—Hydrogen Central SMR Scenarios.xlsm'' and ''GREET1_2021rev1—Hydrogen Central SMR Scenarios—H2A Assumptions.xlsm'' in the docket.

[345] Results are presented from Argonne Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model where the model is set to use landfill gas as the source of natural gas for methane feedstock in the SMR process. To review the complete spreadsheet assumptions, see ''GREET1_2021rev1—Hydrogen Distributed SMR Scenarios.xlsm'' and ''GREET1_2021rev1—Hydrogen Distributed SMR Scenarios—H2A Assumptions.xlsm'' in the docket.

petroleum baseline fuel.[346] However, EPA is not determining whether hydrogen fuel produced from RNG in an SMR meets any particular GHG reduction threshold at this time and we intend to evaluate petitions for hydrogen fuel and determine RIN eligibility on a case-by-case basis, in the context of specific proposed pathways.

3. Hydrogen Fuel Cell Electric Vehicle Efficiency

Similar to battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs) rely on electric motors in their drivetrains, which more efficiently convert fuel into useful work than internal combustion engines. FCEVs can drive approximately 1.5–2.5 times as far using gaseous hydrogen compared to conventional gasoline- or diesel-powered vehicles using an energy-equivalent amount of fuel. While the LCA estimates above from GREET are based on the energy content of hydrogen fuel and do not consider vehicle efficiency, it may be appropriate to calculate lifecycle GHG emissions for hydrogen fuel used in FCEVs by accounting for this increased vehicle fuel efficiency for hydrogen compared to conventional fuels such as diesel or gasoline. This would require the identification of an appropriate value or values to account for this significant difference in relative vehicle powertrain fuel efficiency in our lifecycle GHG calculations.[347]

One consideration in assessing hydrogen FCEV efficiency data is that values for this relatively nascent technology vary significantly across government sources and the peer-reviewed literature. Another consideration is that the varied vehicle duty cycles can yield significantly different vehicle fuel efficiencies relative to conventional gasoline and diesel vehicles (*e.g.,* passenger vehicles compared to long-haul truck freight delivery). Though not meant to be comprehensive, we present various examples of this kind of data below in Table IX.H.3–1. As the data comes presented in various formats, we have conformed the sources below to the same metric for better comparison using the Energy Economy Ratios (EERs) developed by the California Air Resources Board for the California Low Carbon Fuel Standard, which provide a relative ratio for efficiency between two vehicle powertrain/fuel technology combinations. A higher EER value represents a greater relative efficiency of hydrogen FCEVs compared to either gasoline or diesel equivalent technologies.

TABLE IX.H.3–1—EXAMPLE FUEL CELL ELECTRIC VEHICLE EFFICIENCY FACTORS

Source	Relative vehicle fuel efficiency factors comparing FCEVs to conventional vehicles	Details
California Air Resources Board (Low Carbon Fuel Standards)[348].	1.9	Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement) Energy Economy Ratio (EER) Values Relative to Diesel.
	2.5	Light/Medium-Duty Applications (Fuels used as gasoline replacement) Energy Economy Ratio (EER) Values Relative to Gasoline.
Argonne National Laboratory (GREET 2021 Well-to-Wheels Calculator)[349].	1.95	Vehicle fuel efficiency comparison between a modeled diesel passenger vehicle (3,553 btu/mile) divided by modeled hydrogen gas passenger vehicle (1,825 btu/mile).
	2.35	Vehicle fuel efficiency comparison between a modeled gasoline passenger vehicle (4,289 btu/mile) divided by modeled hydrogen gas passenger vehicle (1,825 btu/mile).
National Renewable Energy Laboratory Report: Spatial and Temporal Analysis of the Total Cost of Ownership for Class 8 Tractors and Class 4 Parcel Delivery Trucks (FastSIM)[350].	1.28	Comparison of current class 8 long haul (750 miles) modeled FCEV truck fuel efficiency (11 miles/diesel-gallon equivalent) divided by comparable diesel truck efficiency (8.6 mi/dge).
	1.54	Comparison of current class 4 parcel delivery modeled FCEV truck fuel efficiency (15.6 miles/diesel-gallon equivalent) divided by comparable diesel truck efficiency (10.1 mi/dge).

We can account for the relative efficiency of hydrogen FCEVs and the use of hydrogen fuel by combining the LCA estimates we present from GREET above in Section IX.H.2 that represent GHGs based on the energy content of the fuel, with the relative vehicle efficiency factors in Table IX.H.3–1. By dividing the lifecycle GHG emissions of the fuel by the relative vehicle fuel efficiency, we obtain new lifecycle GHG values, adjusted to represent the relative efficiency of the vehicle compared to either a gasoline or diesel vehicle using the same amount of fuel energy.

For a conservative estimate to illustrate this approach, we can use the lowest vehicle efficiency factor in Table

[346] While it may be reasonable to compare hydrogen fuel against either petroleum gasoline or diesel, as we expect most hydrogen fuel will be used in medium- and heavy-duty fuel cell electric vehicles, we have opted to compare hydrogen fuel against a diesel fuel baseline as the predominant fuel used currently for those vehicles.

[347] We similarly accounted for the relative increase in per mmBtu efficiency use of fuel for battery electric vehicle drivetrains as part of the RFS Pathways II and Technical Amendments to the RFS 2 Standards proposed rule (78 FR 36042). For that lifecycle GHG analysis, accounting for EV efficiency was considered but ultimately not deemed necessary to include for a pathway of renewable electricity from landfill gas due to the GHG percent reduction threshold already exceeding the 60 percent cellulosic biofuel target before considering vehicle efficiency.

[348] California Code of Regulations, Title 17, § 95486.1—Generating and Calculating Credits and Deficits Using Fuel Pathways, Table 5. EER Values for Fuels Used in Light- and Medium-Duty, and Heavy-Duty Applications.

[349] Argonne National Lab (2022) GREET WTW Calculator and Sample Results from GREET 1 2021, *https://greet.es.anl.gov/tools.*

[350] Hunter, C. et al. Spatial and Temporal Analysis of the Total Cost of Ownership for Class 8 Tractors and Class 4 Parcel Delivery Trucks. (2021). NREL/TP–5400–71796, *https://www.osti.gov/servlets/purl/1821615* doi:10.2172/1821615. Values taken from Appendix H: EPA Regulatory Cycle Fuel Economy, Figure H1.

IX.H.3–1, a value that represent Class 8 long-haul trucks from a recent NREL study of 1.28, meaning that it would be expected that FCEV Class 8 long-haul trucks would be approximately 1.28 times more efficient with an equal amount of hydrogen fuel energy compared to a similar diesel engine truck running on an energy-equivalent amount of diesel fuel. Representing the highest efficiency value in Table IX.H.3–1, California Air Resources Board provides a value of 2.5 that represents light- and medium-duty FCEVs that replace similar gasoline-powered vehicles both using an energy-equivalent amount of fuel. Table IX.H.3–2 shows both the unadjusted and newly adjusted lifecycle GHG values assuming a low vehicle efficiency factor of 1.28 and a high vehicle efficiency factor of 2.5.

TABLE IX.H.3–2—LIFECYCLE GHG EMISSIONS FOR PRODUCING HYDROGEN USING SMR WITH LANDFILL GAS FEEDSTOCK, AND ADJUSTED GHG EMISSIONS ACCOUNTING FOR FCEV FUEL EFFICIENCY, ASSUMING LOW AND HIGH VEHICLE EFFICIENCY FACTORS

[$kgCO_2e$/mmBtu]

	Centralized SMR: gaseous hydrogen fuel	Centralized SMR: liquid hydrogen fuel	Distributed SMR: gaseous hydrogen fuel
Lifecycle GHG Emissions (GREET Default Assumptions)	20.5	30.7	49.0
Adjusted Lifecycle GHG Emissions (Assuming Low Vehicle Efficiency Factor: 1.28)	16.0	24.0	38.2
Adjusted Lifecycle GHG Emissions (Assuming High Vehicle Efficiency Factor: 2.5)	8.2	12.3	19.6

We seek public comment on whether it is appropriate to account for the relative vehicle/powertrain efficiency of hydrogen FCEVs compared to conventional gasoline and diesel vehicles for the purpose of lifecycle GHG analysis of hydrogen as a RIN-generating fuel under the RFS program. Furthermore, we seek additional data associated with the relative efficiency of FCEVs compared to conventional vehicles and whether it would be appropriate to make a single average assumption across all vehicle types or if we should define and differentiate different vehicle groupings.

4. Global Warming Potential of Hydrogen

A Global Warming Potential (GWP) is a quantified measure of the globally averaged relative radiative forcing impacts of a particular GHG relative to carbon dioxide. Although hydrogen is not considered a direct greenhouse gas and the IPCC and UNFCCC have not identified and established a GWP associated with hydrogen,[351] we are aware of literature suggesting there are indirect radiative effects caused by the presence of emitted hydrogen in the troposphere.[352] While the LCA values above from GREET do not include a GWP for hydrogen, limited literature suggests that hydrogen released to the troposphere may affect ozone concentrations and prolong the lifetime of resident methane.[353] Due to its extremely small molecular size, it is expected there would be leakage of gaseous hydrogen during production, transportation, storage, and dispensing into vehicles. We seek data on the leakage and venting rates of hydrogen throughout its production, storage, distribution, and use. We also seek comment on additional data and sources of information related to the global warming potential of hydrogen to consider in evaluating the lifecycle GHG emissions of hydrogen as a transportation fuel under the RFS program.

Hydrogen is an evolving source of transportation fuel, and we seek to use the best available data and modeling information as we evaluate the RFS pathway petitions we have before us. We invite comment on the issues discussed above in the context of evaluating the lifecycle GHG emissions of hydrogen fuel from renewable biogas as a feedstock in support of resolving the pathway petitions before the agency. EPA is not addressing the question of whether hydrogen fuel produced from RNG in an SMR meets any GHG reduction threshold at this time and intends to evaluate petitions for hydrogen fuel as well as determine RIN eligibility on a case-by-case basis, in the context of facility-specific pathway petitions.

I. Biogas Regulatory Reform

1. Background

In Section VIII.A, we explain in detail the current regulatory provisions for biogas to renewable CNG/LNG. We also describe in Section VIII.D our reasons for concluding that the current regulatory provisions for biogas to renewable CNG/LNG are not an appropriate model for the design of the proposed eRINs program. We explain that challenges associated with implementing the existing program for biogas to renewable CNG/LNG largely arise from flexibility in the current regulations that allow for any party in the biogas production, distribution, and use chain (and even those outside of it) to generate RINs. This situation is particularly complex in the case where biogas is upgraded to RNG and then injected into the commercial pipeline system because there are potentially dozens of parties that would need to enter into contractual relationships for the movement, storage, and use of the RNG; and the RIN generator must demonstrate both at registration and prior to generating a RIN that each party in the chain produced, distributed, and/or used the RNG in a manner consistent with its use as transportation fuel.

Since promulgation of the existing regulatory provisions for biogas to renewable CNG/LNG in the RFS Pathways II rule,[354] many parties have asked EPA to accept registrations under the existing pathways for the generation of RINs for renewable electricity produced from biogas, and to approve pathways to allow the use of biogas as a biointermediate to produce various types of fuels (*e.g.,* steam methane

[351] Framework Convention on Climate Change; January 31, 2014; Report of the Conference of the Parties at its nineteenth session; held in Warsaw from 11 to 23 November 2013; Addendum; Part two: Action taken by the Conference of the Parties at its nineteenth session; Decision 24/CP.19; Revision of the UNFCCC reporting guidelines on annual inventories for Parties included in Annex I to the Convention; p. 2. (UNFCCC 2014). Available at: *http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf.*

[352] Derwent, R., et al. (2006). Global environmental impacts of the hydrogen economy. International Journal of Nuclear Hydrogen Production and Applications, 1(1), 57. *https://doi.org/10.1504/IJNHPA.2006.009869.*

[353] Forster, Piers, et al. (2018). Changes in Atmospheric Constituents and in Radiative Forcing. IPCC. p. 106. *https://www.ipcc.ch/site/assets/uploads/2018/02/ar4-wg1-chapter2-1.pdf.*

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

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 use of advanced and cellulosic renewable fuels. While we recognize the opportunity to increase the availability of advanced and cellulosic biogas-derived renewable fuels in support of the statutory goals, we also note that allowing biogas or contracted RNG to be used as an input to produce a fuel other than renewable CNG/LNG entails adding yet further layers of complexity to a system that is already complex to implement and oversee. We therefore believe that the existing regulatory requirements for renewable CNG/LNG must first be modified to ensure that biogas is not double-counted in a situation where biogas may have multiple uses. We do not believe that the current regulatory program is well-suited to avoid the double counting of RNG where RNG could be used under the RFS program for more than one use.

As clarification, biogas is the product from anaerobic digesters and landfills before any purification has occurred. After purification, the biogas becomes RNG. Both biogas and RNG can be compressed or liquified to produce renewable CNG or renewable LNG, respectively. Under our proposal, the biogas producer is the party that produces the biogas and the RNG producer is the party that upgrades the biogas into RNG and injects the RNG into the natural gas commercial pipeline system.

The potential expanded use of RNG to renewable electricity, coupled with the potential use of RNG as a biointermediate to produce renewable fuels, could make the program impracticable to oversee within the current regulatory structure. Since biogas may have multiple uses, we believe it would be crucial to take steps to minimize the potential for generating invalid or fraudulent RINs, including the double counting of RINs, should we accept registrations for the use of renewable electricity and/or approve additional pathways to allow the use of biogas as a biointermediate. We believe such measures are necessary because EPA would potentially be tracking and overseeing increased volumes of biogas, and as highlighted in Section VIII.D.4, 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 on a commercial pipeline system). 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. We also have concerns that the existing program's complexity would not be well-suited to cover the potentially hundreds of additional biogas and RNG production facilities that would come online as a result of the proposed eRINs program and allowing biogas and RNG to be used as a biointermediate.

Therefore, in order to better facilitate the potential expanded use of biogas and RNG for renewable electricity and other biointermediates, and to reduce the burden associated with implementing the current biogas to renewable CNG/LNG program, we are proposing to modify the existing compliance and enforcement provisions for biogas to renewable CNG/LNG. The proposed changes would provide a more comprehensive, yet streamlined, tracking and oversight program for biogas and RNG. We recently finalized regulations for other biointermediates.[355] At that time, we deferred taking action to address the use of biogas or RNG as a biointermediate so that we could comprehensively address the unique aspects of biogas for a variety of potential uses, including to produce renewable electricity for the purpose of generating eRINs, in a future rulemaking. This proposal, if finalized, would allow 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. The key elements of the biogas regulatory reforms we are now proposing 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 onto a commercial pipeline;
- A requirement that only 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 chain; and
- Specific provisions to address when biogas or RNG is used as renewable electricity or as a biointermediate.

We discuss each of these proposed key elements in more detail below. Furthermore, we are also proposing to remove regulatory provisions that would no longer be necessary should we finalize the proposed biogas regulatory reforms. For example, should EPA finalize this proposal, much of the documentation currently required to be submitted to EPA at registration would no longer be necessary to submit, including much of the documentation currently required to demonstrate the contractual relationships between each party in the biogas production and distribution chain. We note, however, that under our proposal the registration of biogas production facilities (*e.g.,* landfills and agricultural digesters) would still be maintained because those requirements are necessary to ensure that the biogas was produced from renewable biomass under an EPA-approved pathway consistent with the Clean Air Act.

We are not proposing to revisit or reopen the pathways for biogas established in the RFS Pathways II rule. We are also not proposing any additional pathways for biogas in this action. 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.

2. Biogas Under a Closed Distribution System

There are two approaches to generating RINs from biogas to renewable CNG/LNG under the existing regulations: (1) biogas in a closed, private, non-commercial distribution system that is compressed to renewable CNG/LNG, and (2) biogas upgraded to RNG, injected onto a commercial pipeline system, and then compressed to renewable CNG/LNG.[356] The focus of this proposed regulatory reform deals with RNG injected onto the natural gas commercial pipeline system. We are proposing only minor modifications to the existing regulatory provisions for biogas used to produce a renewable fuel when the biogas is produced, made into a renewable fuel, and used as transportation 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

[355] See 87 FR 39635–39651 (July 1, 2022).

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

an extended production, distribution, and use chain. As such, the focus of the proposed biogas regulatory reform provisions is centered on the movement of biogas that is upgraded to RNG and then injected onto the natural gas commercial pipeline system for later use as transportation fuel.

We are proposing that parties that generate RINs for biogas to renewable CNG/LNG via a closed distribution system would continue to operate under similar regulatory provisions to those currently in place. However, we note that to help ensure consistency in the regulatory requirements for all biogas-derived renewable fuels, we are proposing to move the provisions for biogas to renewable CNG/LNG via a closed distribution system into the newly proposed 40 CFR subpart E. It is not our intention to make significant changes to these regulatory requirements. However, we nevertheless seek comment on whether and how to streamline the regulatory requirements for biogas to renewable CNG/LNG via a closed distribution system.

We also note that under this proposal, to the extent that 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 would have to separately register with EPA, as discussed in Section VIII.L.1. We are proposing this requirement to ensure that biogas producers are treated consistently throughout the program and to help us identify how parties are related in the biogas production, distribution, and use 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.

3. RNG Producer as the RIN Generator

We are proposing that RNG producers would be the sole RIN generators, and that they would generate RINs for RNG they produce and inject into a commercial pipeline. Under the existing regulations, we allow for any party to generate RINs from biogas-derived renewable fuels, even parties that are not part of the biogas production or distribution 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.[357] 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 potential expansion in the use of biogas as a biointermediate, 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 the proposed 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 would effectively be tracked in EMTS from RNG injection through withdrawal for transportation use via the assignment and separation of RINs, as discussed in more detail in Section IX.I.4 below. This approach significantly reduces double counting concerns since a specific volume of RNG would have corresponding RINs assigned to it, and by specifying that the RINs could 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 would 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 injected into the commercial pipeline system.

We also considered designating other parties as the RIN generator. For example, we considered designating the party that produces or uses the renewable CNG as the RIN generator. However, if we proposed such an approach, then we would largely forgo any tracking benefits provided by following transfers of the assigned RIN for a volume of RNG because the RNG would have already traversed the entirety of the natural gas commercial pipeline system before the RIN was generated and assigned. This approach would not remedy the issue that would arise under the existing program with regard to double counting and tracking; *i.e.,* the RNG would have to be tracked via a complicated series of contractual relationships instead of electronically and the downstream party and EPA acting in its oversight capacity would have to go to great lengths to ensure that the RNG was not multiple counted before the RIN was generated.

We recognize that this proposed change could affect a number of parties that are currently registered to generate RINs for biogas to renewable CNG/LNG; however, we think this step is necessary to implement the other proposed changes discussed below that would greatly simplify the program while improving our ability to effectively oversee it. Furthermore, by making the RNG producer the RIN generator, we can greatly improve our ability to track the movement of the RNG via RINs assigned at the point of injection as discussed in Section IX.I.4.

We seek comment on our proposal to designate the RNG producer as the RIN generator for RNG injected into a commercial pipeline system. We also seek comment on whether we should consider designating a different party as the RIN generator.

4. Assignment, Separation, Retirement, and Expiration of RNG RINs

Under this proposal, we are proposing to revise the regulations to specify how parties would assign, separate, and retire RINs generated for RNG. Under the current biogas to renewable CNG/LNG regulations, RINs are generated after any party in the CNG/LNG generation/disposition chain demonstrates that a specific amount of RNG was used as transportation fuel.

For RIN assignment, we are proposing that the RNG producer or RNG importer, *i.e.,* the RIN generator, 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 same volume of RNG as the volume moves through the natural gas commercial pipeline system.[358] The purpose of this proposed requirement is to ensure that the RIN, as tracked through EMTS, would follow the transfer of title of the RNG as the RNG moves through the natural gas commercial pipeline system.

Regarding RIN separation, we are proposing that only the party that demonstrates that the RNG was actually used as transportation fuel would be eligible to separate the RINs generated for the RNG from the RNG itself. For example, the party that compresses the RNG into renewable CNG or renewable LNG and demonstrates that the renewable CNG/LNG is used as

[357] 79 FR 42128, 42144 (July 18, 2014).

[358] 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.

transportation fuel would be eligible to separate the RINs from the RNG. This is a different approach than currently taken under the existing regulations. At present, the party that generates the RINs from a volume of biogas immediately separates any RINs generated for that biogas 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 RNG's distribution chain, which necessitates tracking via contractual relationships, as discussed above, and forgoes any tracking capabilities of EMTS that could be leveraged by tracking assigned RINs for volumes of RNG as the RNG moves through the commercial pipeline system. Our proposed changes would allow for RINs assigned to a given volume of RNG to be tracked via EMTS as the RNG moves through the commercial pipeline system from injecting to withdrawal. Similarly, we are also proposing to clarify that the existing provisions that require obligated parties to separate assigned RINs when they take title to any assigned RINs would 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 to renewable CNG/LNG, we believe that having the party that has the documentation needed to demonstrate that the RNG was used as transportation fuel as renewable CNG or renewable LNG is the party best positioned to separate the RIN because they are also the party best positioned to demonstrate that the RNG is used as transportation fuel in the form of renewable CNG/LNG. This is analogous to the provisions that require parties blending denatured fuel ethanol (DFE) into gasoline to separate any assigned RINs for the denatured fuel ethanol at fuel terminals (*i.e.,* the point at which we believe it is reasonable to assume that the DFE will be used as transportation fuel).[359] Similarly, we believe that once a party has turned RNG into renewable CNG or renewable LNG, we can reasonably assume that the renewable CNG or renewable LNG would be used as transportation fuel.

To address the potential issue of double counting an RNG RIN where a party claims the RNG is used as renewable CNG/LNG and as renewable electricity, we are proposing that renewable electricity generators that use RNG to generate renewable electricity under the proposed eRINs program would have to retire the assigned RINs for the RNG they use to generate renewable electricity. As described in Section VIII.F.5.e, the renewable electricity generator would then transfer the RIN generation allotment for the renewable electricity generated from the RNG to the OEM for the subsequent generation of eRINs. Similarly, for RNG used as a biointermediate, we are proposing to require that the party that uses the RNG as a biointermediate retire the assigned RIN for the RNG used as a biointermediate, and then generate a separate RIN using the procedures for RIN generation for the new renewable fuel.

Under our proposal, RNG RINs would 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 before the annual compliance deadline for the compliance year following the year in which that RNG RIN was generated, the RNG RIN would expire after the subsequent year's compliance deadline has passed. For example, if a RIN is generated for RNG injected into the natural gas commercial pipeline in 2024, then that RNG RIN would 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, to produce renewable electricity, or as a biointermediate, then the RNG RIN would 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 are merely highlighting how the proposed biogas regulatory reform provisions would operate under the existing provisions. We also note that that this provision would 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 would 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 would help encourage parties to use RNG as transportation fuel under the RFS before the RIN expires.

The benefits of this proposed approach to both EPA and the regulated community are manifold. First, this approach would significantly increase the ability for the title to RNG to be tracked and overseen because the transfer of title to RNG would follow the assigned RIN and would be reported in EMTS. EPA and third parties would 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. EPA's proposed approach would greatly simplify the auditing process for both EPA and third parties allowing for increased program oversight.

Second, the proposed approach for RNG RINs would allow us to streamline the registration, reporting, and recordkeeping requirements for RNG and RNG RINs by utilizing EMTS for tracking. This would create a number of efficiencies. With regard to registration, it would eliminate the need for parties to submit contracts at registration. The requisite contractual chains can potentially involve dozens of parties and hundreds of CNG/LNG dispensers or CNG/LNG vehicle fleets. Each contract can be several hundred pages in length, and changing relationships between the parties involved often results in the need for RIN-generating parties to frequently update their registration information. The proposed approach would eliminate these inefficiencies. For reporting, since the RNG and RNG RINs would be tracked in EMTS, we would no longer need to 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, under the proposed approach, EMTS would electronically provide real-time data concerning how a given volume of RNG is transferred and ultimately used. This would eliminate the need for the existing provisions that require RIN generators to obtain documents from every party in the chain in the form of additional contracts, affidavits, or real-time electronic data. These proposed registration, reporting, and recordkeeping requirements would significantly streamline program implementation for EPA and reduce the compliance burden on regulated parties.

[359] 40 CFR 80.1429.

Third, our proposed approach minimizes the potential for a given volume of RNG to be counted more than once. To date, we have not had to address double counting because we have only accepted registrations for converting RNG to renewable CNG/LNG. However, if we finalize the proposed eRINs program and/or allow for the use of biogas as a biointermediate, then double counting would be a concern since RNG could have multiple uses within the RFS program, including converting RNG to renewable CNG/LNG, using RNG to generate renewable electricity under the proposed eRINs program, or using RNG as a biointermediate to produce a renewable fuel other than renewable CNG/LNG or renewable electricity.

We believe our proposed approach mitigates the risk of counting a given volume of RNG more than once because we are proposing to clearly specify the point in the process when RNG RINs may be generated (*i.e.,* at the point where RNG is injected into the commercial pipeline system) and the point in the process when RNG RINs may be separated (*i.e.,* when the RNG is demonstrated to be used as a transportation fuel). Because the RNG may only be injected into the pipeline once and because an assigned RNG RIN may only be separated once, this specificity significantly reduces 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.

5. Proposed Regulatory Provisions for Biogas Regulatory Reform

To assist in the implementation of the treatment of RNG RINs under this proposal, we are proposing to require that specific parties in the RNG disposition/generation chain participate in the RFS program and meet certain regulatory requirements. Under this biogas regulatory reform proposal, we are proposing specific regulatory requirements for 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); and
- The party that demonstrates that the RNG was used as transportation fuel in the form of renewable CNG/LNG, used to generate renewable electricity, or used as a biointermediate to produce a renewable fuel other than renewable CNG/LNG or electricity (the RNG RIN separator).

Like the eRINs proposal described in Section VIII.F, regulatory requirements for each of these key parties is necessary to ensure that the biogas is produced and converted to RNG consistent with CAA and regulatory requirements, and the RNG is used as transportation fuel consistent with Clean Air Act and regulatory requirements. Specifying the requirements applicable to each party would enable us 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. Below, we discuss the specific regulatory requirements we are proposing for each party in the RNG disposition/generation chain.

a. Proposed Requirements for Biogas Producers

Under the biogas regulatory reform proposal, biogas producers would be required to comply with the same proposed regulatory requirements described in Section VIII.F and Section VIII.L because it is our intent to regulate all biogas producers in the same manner regardless of how their biogas may be used under the RFS program. In summary, biogas producers would need to register as described in Section VIII.L.1, submit reports as described in Section VIII.L.2, keep records as described in Section VIII.L.4, comply with PTD requirements for biogas as described in Section VIII.L.3, and undergo an annual attest engagement as described in Section VIII.O.2. The information we are proposing to collect from biogas producers is modelled off of what we currently collect from RIN generators as it relates to biogas production, with the key difference in our proposed approach versus the current regulatory approach being that, under our proposed approach, the biogas producers are responsible for complying with the requirements related to biogas production, as opposed to these requirements being placed on RIN generators.

b. Proposed Requirements for RNG Producers

We are proposing that RNG producers would register as described in Section VIII.L.1. Specifically, RNG producers would demonstrate at registration the RNG production capacity of their facility, how their facility is connected to the natural gas commercial pipeline system, and how they would meet the applicable sampling, testing, and measurement requirements to ensure that RNG meets applicable pipeline specifications as described in Section VIII.L.1. Like other RIN generators, RNG producers would be required to undergo an initial third-party engineer review as well as three-year registration updates which would include a new third-party engineer review.

We are also proposing that RNG producers would be required to submit quarterly reports on the amount of RNG they produced and injected into the natural gas commercial pipeline system. These reports would include information related to the volume and energy content of the injected RNG. We note that these proposed reports are intended to replace existing reporting requirements that RIN generators for biogas to renewable CNG/LNG must submit on a quarterly basis.[360] We are proposing to remove the existing regulatory requirements related to demonstrating that contracts or affidavits were obtained from parties in the RNG distribution chain, since this tracking would now be done via EMTS, as described in Section IX.I.4. We believe this would greatly simplify the quarterly reporting requirements related to RNG when compared to the existing biogas to renewable CNG/LNG regulatory provisions.

As part of this biogas regulatory reform proposal, we are proposing recordkeeping requirements related to RNG production, injection, and RIN generation. For RNG production, RNG producers would be required to 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 would be 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.[361] For RNG RIN generation, RNG producers would be required to 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 Clean Air Act requirements and applicable regulatory requirements, and that the appropriate number of RINs were

[360] RFS0601: Renewable Fuel Producer Supplemental report.

[361] For specific cases where RNG that is trucked to an interconnect, we are proposing the RNG producer measure when loading and unloading each truck.

generated for the RNG injected into the natural gas commercial pipeline system. Since we are proposing to track the movement of assigned RNG RINs in EMTS, we would no longer require that the RIN generator (*i.e.,* RNG producer under this proposed 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 would no longer be needed since EMTS would memorialize the necessary information pertaining to the transfer of the assigned RINs.

We are proposing that transfers of title for RNG would be accompanied by PTDs, consistent with transfers of title of renewable fuels elsewhere under the RFS program. Like PTDs for renewable fuels, the proposed PTDs for RNG would include the name and address 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 proposing that RNG producers would 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) would also apply to transfers of title for the RINs assigned to the RNG. We do not believe any changes to the RIN PTD provisions are necessary, but we seek comment on whether any additional RIN PTD language is needed concerning transfers of assigned RNG RINs.

We are proposing that RNG producers undergo an annual attest engagement like other RIN generators under 40 CFR 80.1464(b). We are also proposing additional procedures that are specific to the production and injection of RNG into the natural gas commercial pipeline system. These proposed attest engagement provisions would verify that records related to the appropriate measurement of RNG injection is consistent with the measurement requirements for RNG described in Section VIII.O.2, and would verify that pipeline injection statements match the amount of RNG reported by RNG producers in quarterly reports is consistent. Attest auditors would also confirm that the correct number of RINs were generated in EMTS compared to the underlying records. The purpose of these proposed attest engagement procedures for RNG producers is to help ensure that RNG RINs were validly generated consistent with EPA's regulatory requirements for RNG. We note that the annual attest engagement procedures for EPA's fuels program would apply to RNG producers like other parties required to undergo an annual attest engagement under EPA's fuels program (*e.g.,* obligated parties and renewable fuel producers). For example, RNG producers would have to identify in their registration information their independent attest auditor, and the independent attest auditor would electronically submit the annual attest engagement report directly to EPA using forms and procedures prescribed by EPA. We seek comment on the proposed annual attest engagement provisions for RNG producers.

c. Proposed Requirements for Parties That Own and Transact RNG RINs

We are proposing 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) would have to 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, used to generate renewable electricity, or used as a biointermediate to produce renewable fuel would be allowed to separate the RNG RIN. In other words, parties that simply transact assigned RNG RINs would not be allowed to separate RINs, and we would intend to design EMTS to prevent them from doing so. As described in more detail in Section IX.I.4, this provision is necessary to ensure that RNG is used as transportation fuel consistent with the Clean Air Act and applicable regulatory requirements.

With the exception of the limitation on RNG RIN separation, we note that we are not otherwise proposing to modify the requirements for parties that own and transact RNG RINs; we are simply highlighting how parties that solely own and transact RNG RINs would operate in the context of the proposed biogas regulations. As such, we will treat any comments on the current regulatory requirements for parties that own and transact RINs as beyond the scope of this action.

d. Proposed Requirements for RNG RIN Separators

Because parties that separate RNG RINs (''RNG RIN separators'') are key to ensuring that RNG is used as transportation fuel, we are proposing additional requirements for RNG RIN separators to ensure that RNG RINs are separated only when allowed. We would expect that the RNG RIN separators would be parties that operate compression equipment to turn RNG into renewable CNG/LNG, dispensers that dispense renewable CNG/LNG into CNG/LNG vehicles, or parties that operate CNG/LNG vehicle fleets; however, under our proposal, we would allow only the party that has the documentation to demonstrate that the RNG was used as transportation fuel in the form of renewable CNG/LNG.

We are proposing that RNG RIN separators would be required to register with EPA prior to RNG RIN separation, submit periodic reports to EPA on RNG RIN separation activities, maintain records, and undergo an annual attest audit. These requirements would apply to any party that separates RINs from RNG but would not include those parties that retire RNG RINs for renewable electricity generation (*i.e.,* renewable electricity generators) and for using biogas as a biointermediate. We also note that, because RNG RIN separators would also own the RINs they are separating and would be able to transact them, the RNG RIN separator would be subject to all other regulatory requirements that apply to owning RINs under the RFS program generally. This includes additional reporting, recordkeeping, PTD, and annual attest engagement requirements. We are not intending to repropose the current regulatory requirements for RIN owners under the RFS program; instead, we are merely highlighting that these requirements would apply to RNG RIN separators. Accordingly, we will treat any comments received on the regulatory requirements for RNG RIN separators as beyond the scope of this action.

The proposed registration requirements for RNG RIN separators would include provision of all the company information currently required from any party that registers under EPA's fuels program, which includes the RFS program.[362] Additionally, in the case of RNG to renewable CNG/LNG, we are proposing that RNG RIN separators would describe at registration their capabilities to compress RNG into renewable CNG/LNG (*i.e.,* convert RNG into renewable CNG/LNG) and their distribution and dispensing capabilities. The purpose of this requirement is to ensure that the RNG RIN separator can convert RNG into renewable CNG/LNG to be used as transportation fuel consistent with the Clean Air Act and applicable regulatory requirements. We note that we currently collect such information from the RIN generator under the current biogas to renewable CNG/LNG regulations; however, under this proposal, such information would instead come directly from the RNG RIN

[362] See 40 CFR 1090.800 and 1090.805.

separator—the party we believe is best positioned to demonstrate that the RNG was converted to renewable CNG/LNG and used as transportation fuel. For renewable electricity generators and parties that use biogas as a biointermediate, the registration requirements for renewable electricity generators described in Section VIII and the requirements for renewable fuel producers under 40 CFR 80.1450 would convey such information.

We are not proposing to require a third-party engineering review for RNG RIN separators. We believe that RNG compression technology and verifying CNG/LNG dispensers is straightforward and that a third-party engineering review would be unnecessarily burdensome. We note that if a party is required to undergo a third-party engineering review because of a different activity, *e.g.,* renewable electricity generation, that party would still need to undergo a third-party engineering review, if required. We seek comment on whether we should require that RNG RIN separators undergo a third-party engineering review as part of their registration requirements.

For periodic reporting, we are proposing that RNG RIN separators submit quarterly reports related to their RNG RIN separation activities. For RNG to renewable CNG/LNG, these reports would denote which facilities/dispensers converted RNG to renewable CNG/LNG and 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 would also serve as the basis for attest auditors and EPA to verify RNG RIN separation activities. We are also proposing to utilize these periodic reports to update the dispensing locations associated with the RNG RIN separator, and we are proposing to require that RNG RIN separators update their CNG/LNG dispensers quarterly. This would eliminate the need for such information to be included in RIN generators' registration information, as required by existing regulations. We seek comment on the proposed quarterly reporting requirements and whether any additional reports are needed to help ensure that RNG is converted to renewable CNG/LNG or used as transportation fuel.

Under this proposal, RNG RIN separators would also be required to submit additional information related to the separation transaction in EMTS. Under the current regulations, we have established a series of codes to identify the reason that a RIN is separated, consistent with the regulatory requirements that allow for RIN separation.[363] To implement the proposed requirements for eRINs and biogas regulatory reform, we would require 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, for use to generate renewable electricity, or for use as a biointermediate. These proposed changes to EMTS would help track the use of RNG under the RFS program, which we believe will improve program oversight. We seek comment on whether any additional functionality in EMTS would be needed to ensure that RNG RINs are properly separated.

We are also proposing that RNG RIN separators would have to maintain records related to their RNG RIN separation activities. For RNG to renewable CNG/LNG, this would include 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 are currently maintained by the RIN generator and under this proposal would instead be maintained by the RNG RIN generator. We believe such 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. We seek comment on whether there are any additional recordkeeping requirements necessary for RNG RIN separators.

We are proposing specific annual attest engagement procedures to verify RNG RIN separation, and we note that these proposed annual attest engagement procedures would be in addition to those currently required for RINs separated under 40 CFR 80.1464. Specifically, we are proposing that an independent attest auditor 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 would be required to be flagged in the annual attest engagement report. These proposed annual attest engagement provisions are necessary to ensure that RNG RINs would only be separated when consistent with applicable regulations. We note that the annual attest engagement procedures for EPA's fuels program would also apply to RNG RIN separators.[364] For example, an RNG RIN separator would have to identify in their registration information their independent attest auditor, and the independent attest auditor would electronically submit the annual attest engagement report directly to EPA using forms and procedures prescribed by EPA.

6. RFS QAP Under Biogas Regulatory Reform

Similar to the proposed eRINs program, we are not proposing to require that biogas producers and RNG producers participate in the RFS QAP. As we noted in Sections VIII.N and IX.I.4, we believe our proposed biogas regulatory reforms would address the issues of double counting of RNG use (*e.g.,* a party claims an amount of RNG as renewable CNG/LNG and as renewable electricity), such that a requirement that biogas producers and RNG producers participate in the RFS QAP is not necessary. We note, however, that should we not finalize the proposed biogas regulatory reform provisions, we intend to require that all participants in both the eRINs and RNG disposition/generation chain participate in the RFS QAP program to help avoid the generation of fraudulent and invalid RINs, including ensuring that RNG is not double counted.

While we are not proposing to require RFS QAP participation, under this proposal, in order to generate a Q–RIN for RNG, both the biogas producer and the RNG producer would be required to be audited by the same independent third-party auditor. We believe that the existing RFS QAP regulatory requirements sufficiently cover the production of biogas and RNG because almost all RINs generated for biogas and RNG under the current program are verified by an independent third-party auditor; therefore, we are not proposing any changes to the RFS QAP provisions for biogas and RNG producers. However, we note that, under our proposal, the parties that transact the assigned RNG RIN and the RNG RIN separator would not need to be included as part of the RFS QAP. This approach

[363] See 40 CFR 80.1429.

[364] See 40 CFR 80.1464 and 1090.1800.

is consistent with the current regulatory treatment of RINs generated for ethanol and biodiesel, and we are not proposing to modify how the RFS QAP considers RIN separations in this action. We note that, as described in Section IX.I.5.d, we are requiring that RNG RIN separators undergo annual attest engagements, which we believe should provide sufficient third-party oversight.

7. RNG Used as Renewable Electricity or a Biointermediate

We are proposing provisions to address situations in which RNG is used to make renewable electricity or RNG is used as a biointermediate. Specifically, we are proposing that renewable electricity generators and renewable fuel producers would be required to retire the RINs assigned to a given volume of RNG prior to using that volume to either generate renewable electricity or produce renewable fuel. For renewable electricity, as described in Section VIII.F.5, the renewable electricity generator could then generate renewable electricity covered by a RIN generation agreement and transfer the data for the renewable electricity generated under the RIN generation agreement to the light-duty OEM, which could then generate eRINs for the amount of renewable electricity used by its fleet. In cases where RNG is used as a biointermediate to produce a different renewable fuel, the applicable RIN generation procedures would vary depending on what fuel is made from the RNG.

We believe our proposed approach would allow for multiple uses of RNG without imposing strict limits on the number of parties that produce or distribute RNG. By assigning RINs to the RNG injected into the commercial pipeline and using EMTS to track the transfer of the assigned RINs between parties that produced the RNG and use the RNG, we believe we can provide flexibility in the use of RNG while maintaining adequate oversight. We believe requiring retirement of the RNG RIN 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 retired.

We seek comment on the proposed approach to require the retirement of assigned RINs when a party uses RNG to make renewable electricity or uses RNG as a biointermediate.

8. RNG Imports and Exports

For imported RNG, we are proposing to maintain the existing regulatory structure whereby either the importer of the RNG or the foreign RNG producer may generate the RINs. Under the RFS program, either the foreign renewable fuel producer may generate RINs (provided certain additional requirements are met) or the importer of the renewable fuel may generate RINs. Under the existing program, approximately 10 percent of all D3 RINs are generated from imported Canadian biogas and, to date, RINs for foreign biogas have only been generated by an importer. Under this proposal, we would maintain the flexibility that either the foreign renewable fuel producer (in this case, the foreign RNG producer) may generate the RIN or an importer may generate the RIN. The sole difference between the proposal and the existing regulations would be that instead of any foreign party in the biogas production and distribution chain, only a foreign RNG producer may be a RIN-generating foreign producer consistent with the approach outlined for domestic biogas production described above. In the case where a foreign RNG producer generates a RIN, the foreign RNG producer would be required to satisfy the additional regulatory requirements for RIN-generating foreign producers at 40 CFR 80.1466 (*i.e.,* submit to U.S. jurisdiction, comply with inspection requirements, and post a bond).

Based on existing registrations for foreign biogas, we do not believe that any changes to existing registrants would be necessary because RNG importers have already served as the RIN generator in all current registrations for Canadian RNG. We seek comment on our proposed approach to dealing with imported biogas used to make biogas-derived renewable fuel. We also note that we describe in more detail how foreign RNG and foreign renewable electricity would be treated under the proposed eRINs program in Section VIII.P.

For exported biogas, RNG, and renewable CNG and renewable LNG, we are not proposing to treat those exports any differently than other exported renewable fuels under the current regulations. 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 proposal, since a RIN would be generated for RNG at the point of injection into a commercial pipeline system, any party that exports the RNG outside of the covered location would incur an exporter RVO under 40 CFR 80.1430 and would be required to satisfy that RVO by retiring the appropriate number and type(s) of RINs. We seek comment on this proposed approach to handling exports of RNG and whether any additional regulatory provisions for RNG exports are necessary.

9. Implementation Date

We recognize that the proposed biogas regulatory reforms would necessitate a transition period for parties that are already generating RINs for biogas under the existing provisions. To allow for this transition, we are proposing an implementation date of January 1, 2024, for the biogas regulatory reforms. Beginning on January 1, 2024, all RNG introduced into the commercial pipeline system would be subject to the RIN generation, assignment, and separation provisions as discussed in Section XI.I.4. Until that time, RINs for the biogas to renewable CNG/LNG pathway must be generated using the existing regulatory provisions. Since most affected parties are currently registered with EPA (*e.g.,* the biogas production facilities and parties that transact RNG RINs), we believe this is a sufficient amount of time for parties to update their registrations to meet the new regulatory requirements. We seek comment on whether additional time is necessary for this transition.

We also recognize that there may be a significant volume of stored RNG that parties are intending to use as renewable CNG/LNG under the existing regulations, and that parties may not be able to use all of that volume prior to January 1, 2024. Therefore, we are proposing to allow parties to use all stored biogas in accordance with existing regulations to generate RINs prior to January 1, 2025. We believe this would provide enough time for parties with stored biogas to utilize their existing inventories and to begin complying with the new regulations. We seek comment on whether the January 1, 2025 deadline provides sufficient time for parties to use stored RNG produced under the existing regulations.

10. Biogas/RNG Storage Prior to Registration

We are proposing to address situations in which biogas or RNG is produced and stored prior to EPA's acceptance of a biogas or RNG producer's registration submission. Specifically, we are proposing that biogas or RNG may be stored on site (*i.e.,* at a storage facility co-located at the biogas or RNG production facility [365])

[365] ''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

Continued

prior to EPA's acceptance of a registration submission, provided that certain conditions are met, as discussed below. In order to ensure equal treatment of all parties, we are also proposing that these storage provisions would also apply to all other biointermediates and renewable fuels.

Under the RFS1 program, we issued guidance [366] stating that parties may assign RINs for renewable fuels that had left the renewable fuel production facility because the RFS1 regulations required that RINs be assigned to renewable fuels at the point of production and did not specifically define what ''point of production'' meant. This was acceptable for the RFS1 program 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 definition of renewable fuel under the RFS1 program).

Under the RFS2 program, in general, we have not allowed 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 (*i.e.,* the renewable fuel has left the renewable fuel production facility). The reason we have not allowed this is because EPA may determine that the fuel was not produced consistently with EPA's regulatory requirements and therefore, not be eligible for RIN generation. However, we have allowed parties to generate RINs for biogas and RNG that was produced prior to EPA acceptance of the RIN generator's registration 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 have allowed biogas/RNG to be stored prior to registration in large part due to the length of time it has taken EPA to review and accept registrations for biogas to renewable CNG/LNG as a result of the existing registration requirements.

As explained in Section IX.I.4, under this proposal we would no longer require that biogas and RNG producers demonstrate that there are contracts between each party in the biogas/RNG production, distribution, and use chains in order to demonstrate transportation use. Therefore, we believe it is no longer necessary 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.

We would, however, continue to allow for the storage onsite of biogas/RNG, as well as all renewable fuels and biointermediates, produced prior to EPA acceptance of a registration submission if certain conditions are met. Specifically, we would allow for storage onsite if 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; and
- 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 storage 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; so long as the producer does not modify their facility, the biogas and RNG produced at these facilities should be able to be utilized to generate RINs. These products would have to be produced in accordance with the applicable regulatory requirements. We are proposing that the biogas or RNG producer must maintain custody of the product because once the product has left their custody, the potential ability of the producer to remedy issues with the product is greatly diminished; this could also result in other parties downstream becoming liable for the product not meeting applicable regulatory requirements. After EPA has accepted the biogas or RNG producer's registration, the stored products could then be used to produce renewable fuel or for the generation of RINs, as applicable.

For renewable electricity, we are proposing that renewable electricity placed on the commercial electric grid serving the contiguous U.S. prior to EPA's acceptance of a renewable electricity generator's registration does not meet these requirements and may not be stored for purposes of RIN generation because we are not aware of a case where the renewable electricity generator could store the renewable electricity on site. We seek comment on all aspects of allowing biogas, RNG, biointermediates, and renewable fuels to be stored prior to registration.

J. Separated Food Waste Recordkeeping Requirements

Under the Clean Air Act, qualifying renewable fuel must be produced from renewable biomass.[367] To ensure that RIN-generating renewable fuels satisfy this requirement, EPA's 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.'' [368] In addition to the generally applicable requirements, EPA's 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.

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

under the control of the same person (or persons under common control).''

[366] Questions and Answers on the Renewable Fuel Standard Program. Page 7. *https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1001T9Z.pdf.*

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

[368] 40 CFR 80.1454(d).

(2) a separated food waste plan.[369] 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 the provision to submit the location of every facility from which separated food waste is collected as a registration requirement and to simply rely on the corresponding recordkeeping requirement;[370] at that time, we noted that renewable fuel producers are also required to retain this information under the recordkeeping requirements under 40 CFR 80.1454.[371]

EPA finalized the proposed removal of the requirement to provide the location of every facility from which separated food waste is collected as part of the information required for registration in 2020.[372] We 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.'' [373] To emphasize that this requirement remains 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(s) 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.'' [374]

Although we emphasize that the requirement for 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 has existed at 40 CFR 80.1454(d) since 2010, we are also aware there are parties that may have suggestions for how to better apply this requirement specifically to separated food waste feedstocks. We are therefore requesting comment on the separated food waste-specific recordkeeping requirement in 40 CFR 80.1454(j)(1)(ii).[375] In particular, we seek comment on how renewable fuel producers using separated food waste as feedstocks can 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 are sufficient to verify that the feedstocks meet the definition of renewable biomass.

EPA has also been engaged in conversations with third party feedstock suppliers, independent auditors, and renewable fuel producers on this topic. Based on these conversations, we are proposing a specific, optional approach to satisfying the applicable recordkeeping requirement on which we are requesting comment, in addition to the general request for comment on approaches above.

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 supplier. While the current 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 proposing an option to allow independent auditors to verify records held by the feedstock supplier by leveraging the biointermediates provisions of the RFS program. While most of our conversations to date have addressed this issue in the context of used cooking oil collection, we believe this proposed option could also be useful for and apply adequately well to third-party collectors of separated yard waste, separated food waste, and separated municipal solid waste.

We are proposing an option under which, in lieu of renewable fuel producers needing to hold the records demonstrating the locations from which the feedstocks were collected, feedstock suppliers could voluntarily comply with the parts of the biointermediates provision relevant to demonstrating that the feedstock used to produce renewable fuel is renewable biomass. If a renewable fuel producer and feedstock supplier opt into this alternative requirement, then the following requirements would need to be met (as described in the proposed 40 CFR 80.1479): the feedstock supplier would need to register with the EPA and must keep all applicable records of feedstock collection; both the renewable fuel producer and feedstock supplier would need to participate in the QAP program using the same QAP provider; and product transfer documents would need to be supplied for feedstocks after leaving the feedstock supplier that include the volume, date, location at time of transfer, and transferor and transferee information. The feedstock suppliers and the renewable fuel producers that process those feedstocks would also be subject to the same liability provisions that apply to biointermediate producers and renewable fuel producers that process biointermediates.

Since the feedstock suppliers are not substantially altering the feedstock before transferring the feedstock, we believe fewer requirements would be necessary than for biointermediates to provide sufficient oversight of the feedstock and renewable fuel production process. Specifically, we are proposing that the feedstock supplier would not need to supply an engineering review, separated food waste plans, separated yard waste plans, or separated MSW plans as a part of registration. However, the renewable fuel producer will still need to supply these documents as part of their registration. Title transfer PTDs and transfer limits would also not be required. In addition, the feedstock would not be considered a biointermediate, so the feedstock supplier could sell feedstock to a biointermediate producer which could sell a biointermediate to a renewable fuel facility. In this situation, all three

[369] 40 CFR 80.1450(1)(vii)(B).

[370] 81 FR 80828, 80902–03 (November, 16, 2016).

[371] *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.'').

[372] 85 FR 7016, 7078 (Feb. 6, 2020).

[373] *Id.* at 7062.

[374] *RFS Power Coalition* v. *U.S. EPA,* No. 20–1046 (D.C. Cir.), Doc. #1882940 at 38–39, filed Jan. 29, 2021.

[375] We are not requesting comment on or reopening the requirement at 40 CFR 80.1454(d).

entities (feedstock supplier, biointermediate production facility and renewable fuel production facility) would need to use the same QAP provider.

We have designed this proposed option to be consistent with the California Air Resources Board's (CARB) approach for verification of similar feedstocks under their low carbon fuel standard (LCFS) program, given that many producers participate in both LCFS and RFS. Under CARB's LCFS program, multiple parties may serve as ''joint applicants'' to demonstrate that LCFS credits were validly created for fuels produced from ''specified source feedstocks'' like used cooking oil and animal fats.[376] Under CARB's LCFS program, applying as joint applicants allows each entity to maintain control of confidential data for the portions of the LCFS pathway they submit.[377] However, in order to ensure that LCFS credits are valid, CARB's LCFS program requires that ''(1) [e]ach joint applicant is subject to all requirements for pathway application, attestations, validation and verification, recordkeeping, pursuant to this subarticle, for the portion of the pathway they control[; and] (2) [a] single entity designated to submit data on behalf of multiple entities within a pathway does not relieve any other entity in the pathway from responsibility for ensuring that the data submitted on its behalf is accurate.'' [378] CARB's LCFS requirements then set up a structure similar to our proposal whereby the party must either maintain (1) ''delivery records that show shipments of feedstock type and quantity directly from the point of origin to the fuel production facility'' or (2) ''information from material balance or energy balance systems that control and record the assignment of input characteristics to output quantities at relevant points along the feedstock supply chain between the point of origin and the fuel production facility.'' [379] Under the second option, joint applicants under CARB's LCFS program must collectively maintain records of the type and quantity of feedstock obtained from each supplier, including feedstock transaction records, feedstock transfer documents, weighbridge tickets, bills of lading or other documentation for all incoming and outgoing feedstocks; maintain records used for material balance and energy balance calculations; and ensure CARB staff and verifier access to audit feedstock suppliers to demonstrate proper accounting of attributes and conformance with certified CI data.[380] CARB's LFCS regulations note that different entities may assume responsibility for different portions of the chain-of-custody, but that all entities must meet the chain of custody requirements collectively.[381] The chain-of-custody requirements, including the underlying records, are verified annually by an independent third party.[382]

As noted above, we have designed our proposed option to be consistent with the LCFS approach, taking into consideration the unique statutory and regulatory structure of the RFS program. Under our proposal, we would essentially allow renewable producers the same choice as LCFS credit generators: either the renewable fuel producer would have to maintain records from the point of origin (*e.g.,* restaurants) demonstrating that the feedstock is renewable biomass, or the feedstock suppliers would maintain the records for the feedstock from the point of origin and have the QAP auditors verify the chain-of-custody. We would not require that underlying records be transmitted between the feedstock supplier and the renewable fuel producer, but rather that the feedstock supplier and the renewable fuel producer would collectively have to demonstrate the chain-of-custody for the feedstock back to the origin of the renewable biomass. Under our proposal, the QAP auditors would verify the chain of custody, which is similar to CARB's annual verification process.

We believe that by allowing renewable fuel producers to opt into these limited additional requirements, more renewable fuel can be produced under the RFS program. We are requesting comments on this proposal and are specifically interested in the perspective of renewable fuel producers, independent auditors, and feedstock suppliers about how this alternative recordkeeping requirement would fit within their current business practices.

K. Definition of Ocean-Going Vessels

We are proposing to amend the definition of ''fuel used in ocean-going vessels'' to ensure that obligated parties are including diesel fuel in their RVOs in a consistent manner and as required by the CAA. Fuel used in ocean-going vessels is explicitly excluded from the CAA's definition of ''transportation fuel,'' [383] and does not need to be included in RVO calculations.[384] Our regulations define 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.'' [385] The term ''ocean-going vessels'' referenced in sub-prong (3), however, is not further defined in the regulations.

In the preamble promulgating the RFS2 regulations, we stated:

> With respect to fuels for use in ocean-going vessels, [the Energy Independence and Security Act (EISA)] specifies that 'transportation fuels' do not include such fuels. We are 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). Thus, fuel for use in ocean-going vessels, or that an obligated party can verify as having been used in an ocean-going vessel, will be excluded from the renewable fuel standards.[386]

This statement made clear that vessels powered by C3 marine engines are ocean-going vessels and that fuel supplied to those vessels do not need to be included in obligated parties' RVO calculations. The reference to ''and some Category (C2) marine engines'' is further explained in the Response to Comments document accompanying the final RFS2 regulations, where we stated:

> With respect to the comments that EPA should not allow the term ''ocean-going vessel'' to include Category 2 engines, we note that Category 1 and Category 2 engines/vessels are generally subject to the NRLM diesel fuel standards. Since NRLM diesel fuel would not be considered part of ''fuels for use in ocean-going vessels'', this means that the vast majority of fuel used by Category 1 and Category 2 engines would be considered part of ''transportation fuels''. However, our recent rulemaking to establish new standards for Category 3 engines included a provision that would effectively allow Category 1 and 2 auxiliary engines installed on Category 3 vessels (*i.e.,* those vessels powered by Category 3 engines) to utilize fuels other than NRLM. This allowance is to reduce the burden that could potentially be caused by requiring that these Category 1 and 2

[376] Cal. Code Regs. tit. 17, § 95488.

[377] Cal. Code Regs. tit. 17, § 95488(b).

[378] Cal. Code Regs. tit. 17, § 95488(b).

[379] Cal. Code Regs. tit. 17, § 95488.8(g).

[380] Cal. Code Regs. tit. 17, § 95488.8(g)(1)(B)(1) through (3).

[381] Cal. Code Regs. tit. 17, § 95488.8(g)(1)(B).

[382] Cal. Code Regs. tit. 17, §§ 95491.1(a)(2) and 95491.1(c)(2)(I).

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

[384] 40 CFR 80.1407(f)(8).

[385] 40 CFR 80.1401.

[386] 75 FR 14670, 14721 (March 26, 2010).

auxiliary engines burn 15 ppm diesel fuel—which could result in a Category 3 vessel needing to carry three different types of fuel onboard. Thus, to the extent that these engines use residual fuel or ECA marine fuel, their fuel would also not be considered ''transportation fuels''.[387]

In other words, the reference to ''and some Category (C2) marine engines'' in the preamble to the final RFS2 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 are proposing 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.'' 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 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. Auxiliary engines are often used for purposes other than propulsion. 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 are also proposing to modify 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 and the flexibilities to certify diesel fuel for multiple purposes as allowed under Fuels Regulatory Streamlining. Specifically, we are proposing to remove the restriction that fuel that meets the requirements of MVNRLM diesel fuel cannot be ECA marine fuel as this exclusion in the definitions conflicts with the designation provisions in 40 CFR part 1090. We note that we are not proposing to change the treatment of certified NTDF under the RFS program in this action.

Under the current definitions for MVNRLM diesel fuel and ECA marine fuel, the definitions exclude 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 must include the designated MVNRLM diesel fuel in their RVO calculations even if the fuel is designated and used as ECA marine fuel.

On February 6, 2020, EPA promulgated regulations to allow refiners and importers to exclude certified non-transportation 15 ppm distillate fuel or certified NTDF from their RVO calculations if certain conditions were met. The definition of certified NTDF includes 15 ppm fuel that is designated as ECA marine fuel. Since the NTDF regulations allow parties to exclude ECA marine fuel that is also certified NTDF from their RVO compliance calculations, we are also 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.

Under EPA's fuel quality regulations in 40 CFR part 1090, we allow diesel fuel manufacturers to apply multiple designations to a batch of diesel fuel so long as all applicable regulatory requirements are met for each designation. A party downstream of the diesel fuel manufacturer may then determine how that batch of diesel fuel is ultimately used consistent with market demand. For example, a diesel fuel manufacturer can designate a diesel fuel batch that meets the ULSD standards as ULSD, ECA marine fuel, and heating oil, and then a terminal operator may use such fuel for any of those uses so long as all applicable regulatory requirements are met.

Under the certified NTDF provisions, in order for diesel fuel to be considered certified NTDF and thus eligible for exclusion from an obligated party's RVO, the diesel fuel must have been certified as meeting the ULSD standards, designated as certified NTDF, designated 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), and not been designated as ULSD or 15 ppm MVNRLM diesel fuel.

This means that regardless of whether a diesel fuel manufacturer designates a batch of fuel for a non-transportation use, if a diesel fuel manufacturer designates the batch as ULSD or MVNRLM diesel fuel, the batch must be included in their RVOs. Together, these provisions provide significant flexibility regarding the designation, distribution, and use of distillate fuels that meet the ULSD standards.

L. Bond Requirement for Foreign RIN-Generating Renewable Fuel Producers

The current bond requirement applicable to foreign RIN-generating renewable fuel producers and Foreign RIN owners was developed in the RFS 1 rule[388] 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. 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 in the past twelve months, RINs in all categories have consistently sold above $1.00 per RIN.[389] The increased value of RINs makes a bond requirement of $0.01 per RIN insufficient to deter potential noncompliance nor is it 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 believe it is necessary to raise the bond requirement to more accurately reflect the current value of RINs so that bonds can serve their intended purposes. We are proposing raising the bond requirement from $0.01 per RIN to $0.30 per RIN, and we are seeking comment on whether this increase is significant enough for the bond to serve its intended purposes.

The existing regulation at 40 CFR 80.1466(h) allows either direct payment to the U.S. Treasury in the calculated amount of a bond or the posting of a surety bond to fulfill the foreign bond requirement. EPA cannot easily process direct payments to the U.S. Treasury made by check, nor can EPA easily refund such payments to the payor. Therefore, EPA proposes to remove direct payment to the U.S. Treasury as an option. We seek comment on how this change affects RIN-generating foreign producers and foreign RIN owners and if there are other options that would provide adequate security, accountability, and ease of use for the EPA, RIN-generating foreign producers, and foreign RIN owners.

[387] U.S. EPA, Renewable Fuel Standards Program (RFS2) Summary and Analysis of Comments, at 3–198–3–200. (February 2010).

[388] 72 FR 24007 (May 1, 2007).

[389] See RFS pricing data available at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.*

M. Definition of Produced From Renewable Biomass

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.'' 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). In the 2020–2022 RFS Annual Rule, 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 this rule, we are re-proposing the definition of ''produced from renewable biomass'' that was in the 2020–2022 RFS Annual Rule, as well as seeking comment on alternative definitions or ways that renewable fuel producers could demonstrate that the fuel they produce meets this statutory requirement.[390]

As described in the 2020–2022 RFS Annual Rule, we believe a definition of ''produced from renewable biomass'' is needed 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 would reduce confusion on this issue. In particular, we want to 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.

In comments on the proposed definition of ''produced from renewable biomass'' in the 2020–2022 RFS Annual Rule commenters identified two primary ways that renewable fuels could meet this statutory requirement. Some commenters supported the proposed definition wherein the energy in the finished fuel is derived from renewable biomass. Other commenters suggested an alternative in which a fuel would be deemed to have been produced from renewable biomass if the mass or molecules in the fuel were from renewable biomass.

The CAA does not define the term ''produced from renewable biomass,'' and we believe that this phrase allows for multiple interpretations, including that renewable fuels must contain energy from renewable biomass or that they must contain mass from renewable biomass. The case for defining produced from renewable biomass as containing energy from renewable biomass is primarily based on the fact that the fundamental purpose of transportation fuel is to provide motive energy to vehicles and engines. Thus, the source of the energy in the finished fuel should be the criterion for determining whether that fuel was produced from qualifying renewable biomass. It is also consistent with the statutory definition that renewable fuel must ''be used to replace or reduce the quantity of fossil fuel present in a transportation fuel.'' Fuel that derives its energy from fossil fuel (a subset of non-renewable feedstocks) is replacing one form of fossil fuel for another, not reducing the quantity of fossil fuel present in a transportation fuel.

Conversely, the case for defining produced from renewable biomass as containing mass from renewable biomass is based on the term ''produced'' and the fact that fuels must also reduce lifecycle GHG emission to qualify as a renewable fuel under the RFS program. As provided in comments on EPA's proposed definition in the 2020–2022 RFS Annual Rule, the definition of ''produced'' is to ''make or manufacture from components or raw materials.''[391] According to this definition it is the components or raw materials (*i.e.,* the mass that comprise a fuel) that determine from what it is produced. Commenters also noted that to qualify as a renewable fuel the fuel must reduce lifecycle GHG emissions by at least 20 percent. These parties claim that the lifecycle GHG emission requirement effectively addresses the sources of energy used to produce renewable fuels and prevents the qualification of fuels that rely on excessive amounts of non-renewable energy sources that would increase GHG emissions in the transportation sector.

To inform our consideration of these two potential definitions of produced from renewable biomass, we also considered how various fuels would be impacted by applying one or the other. The vast majority of renewable fuel pathways that are currently approved under the RFS program would continue to qualify as renewable fuels under either definition of produced from renewable biomass. The majority of these fuels, such as ethanol, biodiesel, CNG/LNG, etc. contain little or no energy or mass from non-renewable biomass. Further, for fuels such as denatured ethanol or biodiesel that do contain energy or mass from non-renewable biomass we have generally accounted for the non-renewable portion of the fuel in the number of RINs generated per gallon of fuel produced.[392] However, the application of the ''produced from renewable biomass'' requirement is less clear for some newer fuel technologies that are being developed by stakeholders.

For some emerging renewable fuel production technologies, these two different definitions of produced from renewable biomass produce very different results. Two examples that illustrate the importance of this definition are hydrogen produced from biogas and e-fuels (fuels made from CO_2, water, and electricity). For a fuel production process where hydrogen is produced from biogas from a qualifying source (*e.g.,* from a landfill or agricultural digester) and biogas is used as both the feedstock and energy source to produce hydrogen in a steam methane reformer (SMR), all of the energy in the hydrogen comes from renewable biomass. Conversely, because half of the mass of hydrogen produced through the SMR process are from water, which does not meet the statutory definition of renewable biomass, only half of the mass is from renewable biomass.

The implications for e-fuels are even more significant, as the definition of produced from renewable biomass would determine not how many RINs could be generated, but whether the fuels qualified as renewable fuel at all. For e-fuels produced using CO_2 from qualifying renewable biomass, such as that produced when fermenting corn starch to ethanol, and wind or solar electricity providing the energy, none of the energy in the finished fuel is from renewable biomass despite the fact that most of the mass in the fuel is from renewable biomass. Theoretically, e-

[390] Any comments submitted on this matter in the 2020–2022 RVO action must be re-submitted to the docket for this rule to be considered. Any comments that are not re-submitted to the docket for this action will not be considered.

[391] See definition of ''produce.'' *Oxford Languages Dictionary. https://languages.oup.com/google-dictionary-en.*

[392] The renewable content of a renewable fuel is also addressed in the calculation of its Equivalence Value under 40 CFR 80.1415. In the specific case of ethanol, the denaturant that is added to ethanol is considered to be renewable despite the fact that it is not produced from renewable biomass in order to maintain consistency with the program's original expectations. This issue is discussed in the 2007 rulemaking which established the RFS program. 72 FR 23920 (May 1, 2007). Similarly, we have accounted for the methanol used to produce biodiesel (which is generally produced from non-renewable natural gas) in the equivalence value for biodiesel.

fuels produced using CO_2 from qualifying biomass and electricity generated using natural gas or coal could also qualify as a renewable fuel if the definition of produced form renewable biomass required that the mass of the fuel come from renewable biomass, but it is very unlikely that such fuels would meet the GHG reduction threshold to qualify as renewable fuel. For e-fuels produced using CO_2 from sources other than renewable biomass, such as CO_2 captured from the air or a coal power plant, and electricity generated using qualifying biogas, all of the energy in the fuel is from renewable biomass but none of the mass of the fuel is from renewable biomass.

As the examples listed here demonstrate, under either interpretation of what it means for a fuel to be produced from renewable biomass there are situations where a fuel would only be partially produced from renewable biomass. These are cases where some of the energy or the mass in the finished fuel is from renewable biomass and the remainder is not. In comments on the 2020–2022 RFS Annual Rule NPRM several parties raised concerns that our proposed definition of produced from renewable biomass would disqualify fuels from being considered renewable fuel, and thus eligible to generate RINs, if even a portion of the fuel was not produced from renewable biomass. These commenters often noted that such a strict interpretation would disqualify fuels such as biodiesel and renewable diesel that contain some non-renewable content. This was not the intent of the definition of produced from renewable biomass that we proposed in that action, nor our intent in this re-proposal. While we do not believe that fuel producers should be able to generate RINs for the portion of the finished fuel that is not derived from renewable biomass, we are not proposing to completely disqualify fuels that contain any portion of non-renewable biomass. Rather, such fuels are subject to equations in the regulations for the RFS program that determine the portion of the fuel that is produced from renewable biomass and can only generate RINs for this portion of the fuel. We note that as part of this proposal to define ''produced from renewable biomass'' we are also proposing new regulations for determining the renewable content of fuels that are produced from both renewable biomass and feedstocks that are not renewable biomass, fuels that contain process energy that is not derived from renewable biomass, and fuels that are produced through multiple pathways with different D codes. These new regulations are discussed in greater detail at the end of this section.

Further examples of how different fuel types would qualify under the two potential definitions, including fuels that are produced from both renewable and non-renewable biomass, are shown in Table IX.M–1. In this table the term feedstock is used to refer to the source or sources of the mass in the finished fuel. The energy in the finished fuel could come exclusively from the feedstock (if the process of converting the feedstock is exothermic) or could come from both the feedstock and the process energy (if the process of converting the feedstock is endothermic). Ethanol and biodiesel are examples of fuels where all of the energy in the fuel comes from the feedstock. In these cases, the source of the process energy has no impact on whether a fuel is produced from renewable biomass, but the source of the process energy does impact the lifecycle GHG emissions of the fuel. Hydrogen produced through an SMR process is an example where some of the energy in the fuel comes from the process energy. In situations where some of the energy in the fuel comes from the process energy whether the process energy is renewable biomass or not impacts the degree to which the finished fuel is produced from renewable biomass if we define produced from renewable biomass based on the energy in the finished fuel. For example, because a portion of the energy in hydrogen produced using an SMR process comes from the process energy, hydrogen produced using this process would generate a greater number of RINs if the process energy is from qualifying biogas (renewable biomass) than if the process energy is from natural gas (not renewable biomass). We note that the fuels and values in this table are only illustrative and do not represent determinations as to the eligibility of a fuel or the percentage of a fuel that would be produced from renewable biomass under these respective definitions.

TABLE IX.M–1—RENEWABLE CONTENT OF VARIOUS FUELS UNDER DIFFERENT DEFINITIONS OF PRODUCED FROM RENEWABLE BIOMASS

[Illustrative examples]

Fuel	Feedstock	Process energy	Definition of ''produced from renewable biomass''	
			Energy from renewable biomass (%)	Mass from renewable biomass (%)
Ethanol	Corn Starch	Natural Gas	100	100
Biodiesel	Soybean Oil and Methanol	Natural Gas	95	95
CNG/LNG	Biogas	Grid Electricity	100	100
Hydrogen (SMR)	Biogas and Water	Biogas	100	50
Hydrogen (SMR)	Biogas and Water	Natural Gas	65	50
Hydrogen (Electrolysis)	Water	Biogas Electricity	100	0
Hydrogen (Electrolysis)	Water	Wind/Solar Electricity	0	0
Electricity	Biogas	Biogas	100	N/A
eFuel	Renewable Biomass CO_2	Wind/Solar Electricity	0	90
eFuel	Renewable Biomass CO_2	Coal/Natural Gas Electricity	0	90
eFuel	Non-Renewable Biomass CO_2 (Air Capture or Fossil CO_2).	Biogas Electricity	100	0

In this rule, we are proposing to add a definition of ''produced from renewable biomass'' to the regulations at 40 CFR 80.2. We propose that produced from renewable biomass means that the energy in the finished fuel or

biointermediate must come from renewable biomass.[393] We recognize that this is not the only potentially reasonable definition of produced from renewable biomass, and that the choice of this definition could have a significant impact on the development of some fuel production technologies with the potential to significantly reduce GHG emissions from the transportation sector. We are therefore requesting comment on an alternative definition: that produced from renewable biomass would mean that the mass of the finished fuel or biointermediate must come from renewable biomass. We note that one potential challenge with this definition is that electricity, for which we are proposing regulations to enable the generation of RINs when the electricity is generated from qualifying biogas or renewable natural gas and used as transportation fuel, contains no mass from the biogas or renewable natural gas. We therefore seek comment on how electricity, which EPA determined in 2010 could meet the statutory definition of renewable fuel, would be treated in the RFS program if this alternative definition were finalized.[394]

In response to the proposed definition of produced from renewable biomass in the 2020–2022 RFS Annual Rule we also received comments saying that EPA should interpret this phrase as broadly as possible. Parties making these comments generally argued that EPA should seek to leverage the incentives provided by the RFS program to reduce GHG emissions to the greatest extent possible, and that a broad definition of produced from renewable biomass would best achieve this aim. Several of these parties also stated that given the existence of multiple potentially reasonable interpretations of this phrase EPA should allow any fuel that can demonstrate that it is produced from renewable biomass under any reasonable interpretation to be eligible to generate RINs under the RFS program. We are therefore requesting comment on an approach that would allow fuels to qualify as renewable fuel under the RFS program if producers can demonstrate that either the molecules contained in the fuel or the energy in the fuel was sourced from renewable biomass.[395]

We are also including an alternative set of draft regulations in a technical memorandum [396] that would be consistent with defining produced from renewable biomass such that the mass in the finished fuel or biointermediate must come from renewable biomass. We would intend to adopt these alternative proposed regulations if we finalized this alternative definition of produced from renewable biomass. Were we to finalize a definition of produced from renewable biomass allowing fuels to qualify under the RFS program if the producer could demonstrate that either the mass or the energy in the fuel are sourced from renewable biomass, we anticipate that we would finalize regulations consistent with the proposed regulatory changes, but we would also include the unique elements from the alternative regulations.

Consistent with the proposed definition of produced from renewable biomass (that the energy in the finished fuel or biointermediate must come from renewable biomass), we are proposing modifications to the existing regulatory previsions in 40 CFR 80.1426(f)(3) for determining the number of RINs that can be generated for fuels produced from multiple pathways with different D codes. These proposed changes would ensure that the RINs of different D codes are generated proportional to the energy in the fuel that came from the corresponding pathways.[397] For example, if a renewable fuel producer simultaneously converted waste sugary beverages (*i.e.,* separated food waste qualifying for D5 RINs) with corn starch (*i.e.,* feedstock qualifying for D6 RINs) to produce ethanol via fermentation, these proposed changes would base RIN generation by pathway on the relative proportion of energy in the final fuel attributed to the feedstocks by D code. If 10 percent of the energy in the ethanol came from separated food waste, then 10 percent of the RINs would be generated under the D5 pathway.

We are also proposing changes to regulatory provisions related to co-processed fuels to ensure that they would be consistent with the proposed definition of produced from renewable biomass. The existing regulations contain the following definition in 40 CFR 80.1401:

> *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.

This definition states that the feedstocks used to produce a fuel determine whether the fuel is co-processed or not, which in turn determines whether the fuel producers must generate fewer RINs than they otherwise would if the fuel had not been produced from co-processing to account for the feedstock that does not qualify as renewable biomass. As with the definition of produced from renewable biomass, this definition for co-processed may be reasonable for many of the existing pathways, where nearly all of the energy and molecules in the fuel come from the feedstocks. However, with the narrow focus on the feedstocks used to produce a fuel this definition of co-processed does not reflect the fact that for other potential pathways such as hydrogen and e-fuels a portion of the energy in the fuel comes from the process energy. Thus, to be consistent with our proposed definition of produced from renewable biomass, we are also proposing to change the definition of co-processed to a definition of co-processed fuel or co-processed intermediate to mean a fuel or intermediate that contains energy from both renewable biomass and non-renewable biomass.

We are also proposing new regulatory provisions and modifications to the existing regulatory provisions in 80.1426(f)(4) for determining the number of RINs that can be generated for fuels that are co-processed that would be consistent with the proposed revision to the definition of co-processed. These proposed changes would provide greater clarity on the required methods for determining the number of RINs that can be generated for co-processed fuels. The proposed changes also add a new formula for cases where a portion of the energy in the fuel comes from the process energy, rather than from the feedstocks. We are also proposing to update the registration requirements in 80.1450(b)(1)(xviii) and recordkeeping requirements in 80.1454(b)(3)(ix) to ensure that the equations used for determining the number of RINs are used appropriately and that sufficient records exist for oversight and enforcement.

We note that under this proposal, we believe that most producers would be largely unaffected because they either

[393] Because biointermediates, like renewable fuels, must be produced from renewable biomass to qualify in the RFS program we are proposing that the definition of produced from renewable biomass apply to both finished fuels and biointermediates.

[394] See Section VIII.A.1 for a further discussion of this topic.

[395] The fuel would also have to meet the other requirements for qualifying as a renewable fuel, including being used to replace or reduce the quantity of fossil fuel present in a transportation fuel and meeting the GHG reduction requirements.

[396] Draft Regulations for the Alternative Definition of Produced from Renewable Biomass. Memorandum from EPA to Docket EPA–HQ–OAR–2021–0427.

[397] We believe this change addresses a comment on 2020–2022 RFS rule that suggested that the current RIN apportionment equations biased higher energy density feedstocks. See Docket Item No. EPA–HQ–OAR–2021–0324–0434.

do not co-process renewable biomass with non-renewable biomass feedstocks or have already been registered for co-processing and would continue to use their currently registered method of determining the number of RINs to be generated from a co-processed fuel. However, under this proposal, we believe that renewable diesel produced via hydrotreating would be affected because some of the energy in the fuel comes from hydrogen, which in many cases is produced from natural gas. Under the proposed approach, they would generate RINs based on the portion of the energy in the renewable diesel that is from renewable biomass.

Recognizing that this would be a change from current RIN generation procedures, we seek comment on potential ways to address this situation. One option is to maintain the proposal (which would result in renewable diesel producers using hydrogen produced from natural gas generating slightly fewer RINs than under the current regulations) and, in a future action, allow for parties to replace the hydrogen with renewable hydrogen (*i.e.,* hydrogen produced from biogas that is produced from renewable biomass) for RIN generation. Some parties have discussed the possibility of using renewable hydrogen as a substitute for the fossil-derived hydrogen for the generation of advanced or cellulosic RINs based on the energy in the renewable diesel produced from the renewable hydrogen. We believe that the existing regulations do not currently accommodate the generation of such RINs in part because the RIN generation procedure for renewable diesel is to assume that 100 percent of the renewable diesel came from the non-hydrogen feedstocks.[398] This proposal would allow parties that wished to replace fossil-derived with renewable hydrogen the opportunity to generate additional RINs proportional to the amount of energy in the renewable diesel that came from renewable hydrogen.

Another option would be to adjust the equivalence value for RIN generation for renewable diesel to account for the fact that a portion of the energy in the fuel was not produced from renewable biomass. We could do this in two ways. First, we could increase the minimum level of energy per gallon needed to qualify for the existing equivalence value for renewable diesel (1.7) to account for the non-renewable portion of the co-processed fuel. Under this option, the minimum amount of energy per gallon needed to qualify for the 1.7 RINs per gallon equivalence value would need to be increased from 123,500 Btu/gallon to account for the non-renewable portion of the co-processed renewable diesel. Alternatively, we could lower the equivalence value itself from 1.7 RINs per gallon to 1.6 RINs per gallon to accommodate the non-renewable portion of the co-processed fuel, and adjust the minimum quantity of BTUs per gallon necessary to qualify for this equivalence value accordingly. The second option is similar to the approach we took with biodiesel to deal with the fact that some of the energy in biodiesel is a result of non-renewable methanol to produce the biodiesel.[399]

We request comment on these proposed regulatory changes, as well as the draft regulations for the alternative proposed definition of produced from renewable biomass.

N. Limiting RIN Separation Amounts

We are proposing to limit the assignment to and separation of RINs for a gallon of renewable fuel (including RNG) to the equivalence value of the renewable fuel. Under the current RFS regulations, parties are allowed to assign and separate RINs to a volume of renewable fuel up to 2.5 RINs per gallon.[400]

This proposed change is necessary for the proposed biogas regulatory reform provisions to ensure that only the RINs generated for and assigned to the specific volume of RNG injected into the natural gas commercial pipeline system are separated after the RNG has been used as transportation fuel. Without this proposed change, it would be possible for parties to assign additional RINs to the volume of RNG, which may be inadvertently or improperly separated by downstream parties. This issue arises from how RINs are transacted in EMTS. By default, EMTS separates RINs in a RIN-owner's account on a first in, first out basis; *i.e.,* when a party separates RINs, it separates the first RINs received in their account, not necessarily the RINs that were generated from the specific volume of renewable fuel. Each party that transacted the inadvertently separated RIN would have a potential violation which would be unnecessarily burdensome on industry. We did not foresee this occurrence when we originally promulgated the regulations and set up EMTS, but now recognize it as an issue. An alternative to limiting RIN assignment and separation to the equivalence value of the fuel would be to redesign EMTS which would take significant resources and time and likely disrupt current RIN transaction processes by industry. Such an effort would also likely delay the implementation date of the biogas regulatory reform provisions and consequently the eRINs proposal.

We also believe this change could help bring transparency to RIN assignment and separation practices for other renewable fuels. We are aware of practices where renewable fuel producers, in coordination with an obligated party, use the separation provisions of 40 CFR 80.1429(b)(2) to separate RINs assigned to volumes of renewable fuel so that a renewable fuel producer can obtain both the separated RINs and RIN-less renewable fuels and then later assign RINs from other producers to the fuel or sell the fuel without RINs. This process, sometimes called ''RIN-flashing,'' can lead to parties that transact RINs or fuel to be less aware of who made the fuel or generated the RINs. One of the regulatory mechanisms that parties use to move these separated RINs is the ability to assign more RINs to a volume of renewable fuel than were able to be generated for the fuel using the equivalence value. Again, we did not foresee parties using the regulations in this manner when we promulgated them and the process of ''RIN-flashing,'' which undermines the ability of parties to ascertain the origin and validity of fuels and RINs, is contrary to our intent. By setting the separation limit to the equivalence value, parties would not be able to move excess separated RINs with a volume of renewable fuel and would be disincentivized from engaging in so-called RIN-flashing.

Imposing the proposed limitation of RIN assignment and separation to be based on the equivalence value of the renewable fuel would also help EPA implement the RFS program because we could establish a single set of rules that apply to all RINs instead of having separate sets of rules that apply to RNG RINs and to non-RNG RINs. This would also facilitate EPA to implement the proposed eRINs program and biogas regulatory reform provisions in the proposed timeframes.

We understand that this change would likely require parties that currently transact RINs to make adjustments to their RIN assignment and separation practices. As such, we are proposing that this change would go into effect on January 1, 2024. We seek comment on our proposal to limit separations to the equivalence value of the renewable fuel.

[398] See 40 CFR 80.1426(f)(2).

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

[400] See 40 CFR 80.1426(b).

O. Technical Amendments

We are proposing to make 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 IX.O–1.

TABLE IX.O–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, 80.24, and 80.1415 through 80.1478	Removing all references to ''the Administrator'' and replacing them with ''EPA''.
80.1401, 80.1408, and 1090.1015	Amending the definition of certified non-transportation distillate fuel (NTDF) at 40 CFR 80.1401 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.
80.1401 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.

X. 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

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. EPA prepared an analysis of potential costs and benefits associated with this action. This analysis is presented in the DRIA, available in the docket for this action.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for 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 2722.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

We are proposing compliance provisions necessary to ensure that the production, distribution, and use of biogas, renewable electricity, and RINs are consistent with Clean Air Act requirements under the RFS program. These proposed compliance provisions include registration, reporting, product transfer documents (PTDs), and recordkeeping requirements. The information requirements are under 40 CFR part 80, subpart M, 40 CFR part 1090, and proposed subpart E. Interested parties may wish to review the following related ICRs: Fuels Regulatory Streamlining (Final Rule), OMB Control Number 2060–0731, expires January 31, 2024, and Renewable Fuel Standard (RFS) Program (Renewal), OMB Control Number 2060–0725, submitted for renewal on August 31, 2022, and pending OMB approval.

Respondents/affected entities: Biogas producers; renewable energy generators; renewable electricity RIN generators (RERGs); renewable natural gas (RNG) producers; RNG importers; producers of biogas-derived renewable fuel in a closed distribution system; RNG RIN separators; and third parties; including third party engineers, attest auditors, QAP providers.

Respondent's obligation to respond: Mandatory, under 40 CFR parts 80 and 1090.

Estimated number of respondents: 10,454.

Frequency of response: On occasion, monthly, quarterly, or annually.

Total estimated burden: 181,794 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $22,422,240, all purchased services, and which includes $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than February 28, 2023.

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.

With respect to eRIN regulatory program discussed in Section VIII, participation in the proposed renewable electricity program would be purely voluntary. We do not believe that a small biogas producer, renewable electricity generator, or light-duty OEM would choose to take advantage of the proposed eRIN program unless there is

sufficient economic incentive for them to do so. No party would be compelled to produce or use biogas or renewable electricity, and as such, any costs associated with these provisions would also be purely voluntary. Also, the proposed eRIN program would create new opportunities for small entities that may be able to build smaller operations or develop previously uneconomical projects. These entities would likely not be able to otherwise participate in the RFS program. With respect to the other amendments to the RFS regulations, this action proposes to make corrections and modifications to those regulations that would make compliance more straightforward. As such, we do not anticipate that there would be any significant adverse economic impact on directly regulated small entities as a result of the proposed provisions.

The small entities directly regulated by the annual percentage standards associated with the RFS volumes are small refiners that produce gasoline or diesel fuel, which are defined at 13 CFR 121.201. To evaluate the impacts of the volume requirements on small entities, we have conducted a screening analysis [401] 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.[402] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchase separated RINs. The costs of the RFS program are thus being passed on to consumers in the 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 small entities can take advantage of. 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 SBREFA panel or through comments, but we did not adopt them, in part because we had serious concerns regarding our authority to do so.

In sum, this proposed rule would 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 would contain 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 the proposed rule are discussed in Section IV and in the DRIA.

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, 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 an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children.

Children are more susceptible than adults to many air pollutants because of differences in physiology, higher per body weight breathing rates and consumption, rapid development of the brain and bodily systems, and 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.

Infants and children breathe at much higher rates per body weight than adults, with infants under one year of age having a breathing rate up to five times that of adults.[403] In addition, children breathe through their mouths more than adults and their nasal passages are less effective at removing pollutants, which leads to a higher deposition fraction in their lungs.[404]

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.[405] Exposure at a young age to these carcinogens could lead to a higher risk of developing cancer later in life.

The biofuel volumes associated with this rulemaking may reduce GHGs, potentially mitigating the impacts of climate change on children. In addition, to the extent increased use of renewable diesel resulting from this rule reduces end-use emissions, there may be public

[401] See DRIA Chapter 10.

[402] For a further discussion of the ability of obligated parties—including small refiners—to recover the cost of RINs, see ''April 2022 Denial of Petitions for RFS Small Refinery Exemption,'' EPA–420–R–22–005, April 2022 and ''June 2022 Denial of Petitions for RFS Small Refinery Exemption,'' EPA–420–R–22–011, June 2022.

[403] U.S. Environmental Protection Agency. (2009). Metabolically-derived ventilation rates: A revised approach based upon oxygen consumption rates. Washington, DC: Office of Research and Development. EPA/600/R–06/129F. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=202543.*

[404] Foos, B.; Marty, M.; Schwartz, J.; Bennet, W.; Moya, J.; Jarabek, A.M.; Salmon, A.G. (2008) Focusing on children's inhalation dosimetry and health effects for risk assessment: An introduction. J Toxicol Environ Health 71A: 149–165.

[405] 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.*

health benefits for children, particularly those who live or go to school near roads. Analysis conducted by EPA indicates that millions of Americans live within a few hundred yards of a truck route.[406] However, emissions data for vehicles running on renewable diesel fuel are too limited at present to draw any conclusions about potential air quality impacts.

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 proposes 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) & Incorporation by Reference

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 National Standards Institute (ANSI), American Petroleum Institute (API), American Public Health Association (APHA), and ASTM International (ASTM). A detailed discussion of these test methods and standards can be found in Section VIII. The standards and test methods may be obtained through the ANSI website (*www.ansi.org*) or by calling ANSI at (212) 642–4980, the API website (*www.api.org*) or by calling API at (202) 682–8000, the APHA website (*www.standardmethods.org*) or by calling APHA at (202) 777–2742, and the ASTM website (*www.astm.org*) or by calling ASTM at (877) 909–2786. ANSI, API, APHA, and ASTM routinely update many of their reference documents. If an updated version of any of reference documents included in this proposal is published, we will consider referencing that updated version in the final rule. (In addition to the standards and test methods listed below, ASTM D975, ASTM D1250, ASTM D4442, ASTM D4444, ASTM D6751, ASTM D6866, and ASTM E870 are also referenced in the regulatory text of this proposed rule. They were approved for IBR for the sections referenced as of July 1, 2022, and no changes are being proposed. ASTM E711 is also referenced in the regulatory text of this proposed rule. It was approved for IBR for the section referenced as of July 1, 2010, and no changes are being proposed.)

TABLE X.I1—STANDARDS AND TEST METHODS TO BE INCORPORATED BY REFERENCE

Organization and standard or test method	Description
ANSI C12.20–2015, Electricity Meters 0.1, 0.2, And 0.5 Accuracy Classes, February 17, 2017.	Standard for measuring the flow of electrical power, including physical aspects of the meter as well as performance criteria.
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, April 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—Natural Gas Fluids Measurement Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, September 2012.	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—Natural Gas Fluids Measurement Section 3—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 14.3.3–2021, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, November 2013.	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—Natural Gas Fluids Measurement Section 3—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, September 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 2540, Solids In: Standard Methods For the Examination of Water and Wastewater, approved 2015, revised 2020.	Standard describing how to measure the total solids, volatile solids, and other solid properties of wastewater sludge and similar substances.
ASTM D3588–98(2017)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

[406] U.S. EPA (2022). Estimation of Population Size and Demographic Characteristics among People Living Near Truck Routes in the Conterminous United States. Memorandum to Docket.EPA–HQ–OAR–2019–0055.

TABLE X.I1—STANDARDS AND TEST METHODS TO BE INCORPORATED BY REFERENCE—Continued

Organization and standard or test method	Description
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 D7164–21, 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.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations, and Low-Income Populations

EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). 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 DRIA Chapter 9.

This proposed rule would reduce GHG emissions, which would benefit minority populations, low-income populations, and indigenous populations. The manner in which the market responds to the provisions in this proposed rule could also have non-GHG impacts. Replacing petroleum fuels with renewable fuels will 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.

XI. 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 proposes to amend 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.

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.

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: *http://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.

Audited party means a party that pays for or receives services from an independent third party under this part.

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.

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 § 80.3).

Biodiesel distillation bottoms means the heavier product from distillation at a biodiesel production facility that does not meet the definition of biodiesel.

Biogas or *raw biogas* means a mixture of biomethane, inert gases, and impurities that is produced through the anaerobic digestion of renewable biomass prior to any treatment to remove inert gases and impurities or adding non-biogas components.

Biogas closed distribution system means the infrastructure contained between when biogas is produced, used to produce a biogas-derived renewable fuel, and when the biogas-derived renewable fuel is used as transportation fuel within a discrete location or series of locations that does not include placement of 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, renewable electricity, 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 that a renewable fuel producer uses to produce a renewable fuel other than renewable CNG/LNG or renewable electricity.

Biointermediate means any feedstock material that is intended for use to produce renewable fuel and meets all of 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 or renewable electricity.

(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.

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, hemi-cellulose, or lignin that has lifecycle greenhouse gas emissions that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.

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).

Charging efficiency means the average fraction of energy stored in an EV's or PHEV's battery relative to the energy obtained from the electricity distribution system.

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.

Conterminous electricity distribution system means the major and minor alternating current (AC) power grids that supply electricity to or within the covered location (excluding Hawaii).

Continuous measurement means the automated measurement of specified parameters of biogas, natural gas, or electricity as follows:

(1) For in-line GC meters, automated measurement must occur at least once every 15 minutes.

(2) For flow meters, automated measurement must occur at least once every 6 seconds.

(3) For all other meters, automated measurement must occur at least once every 2 seconds.

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 or *CG* means any gasoline that has been certified under 40 CFR 1090.1000(b) and is not RFG.

Co-processed cellulosic diesel is any renewable fuel that meets the definition of cellulosic biofuel 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) 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.

Co-processed fuel or *co-processed intermediate* means a fuel or intermediate that was partially produced from renewable biomass by any of the following:

(1) The simultaneous processing of renewable biomass with non-renewable feedstock in the same unit.

(2) The use of heat or electricity that is not from renewable biomass and is converted to energy in the fuel or intermediate.

(3) The commingling of renewable fuel or biointermediate with non-renewable material and for which the volume of renewable fuel or biointermediate cannot be separately measured during the production process.

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.

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.

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) and (2) 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.

Electrical vehicle miles traveled (eVMT) means the average annual vehicle miles travelled for an EV or average annual miles traveled in the all-electric mode of a PHEV.

Electric generating unit (EGU) means a combustion unit that produces electricity.

Electric vehicle (EV) has the meaning given in 40 CFR 86.1803–01.

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 subpart:

(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 or *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 or a biointermediate 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).

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.

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 electricity generator means any person who owns, leases, operates, controls, or supervises a renewable electricity generation facility outside of the United States.

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 subpart 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 or *BOB* has the meaning given in 40 CFR 1090.80.

Gasoline treated as blendstock or *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 60 degrees Fahrenheit and 1 atmosphere of pressure, 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.

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.

LDV/T has the meaning given in 40 CFR 86.1803–01.

Light-duty truck has the meaning given in 40 CFR 86.1803–01.

Light-duty vehicle has the meaning given in 40 CFR 86.1803–01.

Liquefied petroleum gas or *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.

Model has the meaning given in 40 CFR 86.1803–01.

Model year has the meaning given in 40 CFR 86.1803–01.

Motor vehicle has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550(2)).

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 § 80.1450(b)(1)(v)(C).

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 § 80.3) 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 primarily (*i.e.,* ≥75%) propelled by engines meeting the definition of ''Category 3'' in 40 CFR 1042.901.

Original equipment manufacturer (OEM) has the meaning given in 40 CFR 86.1803–01.

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.

Plug-in hybrid electric vehicle (PHEV) has the meaning given in 40 CFR 86.1803–01.

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.

Produced from renewable biomass means that the energy in the finished fuel or biointermediate comes from renewable biomass.

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 or *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 or *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 or *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 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 and is covered under a RIN generation agreement under § 80.135.

Renewable electricity data mean the information that describes the monthly renewable electricity generation for a renewable electricity generation facility covered by a RIN generation agreement.

Renewable electricity generation facility means any facility where renewable electricity is produced.

Renewable electricity generator means any person who owns, leases, operates, controls, or supervises a renewable electricity generation facility.

Renewable electricity RIN generator (RERG) means any OEM of electric and plug-in hybrid electric LDV/Ts registered to generate RINs for renewable electricity.

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 subpart.

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 or RNG that goes through the process of liquefaction in which it is cooled below its boiling point for use as transportation fuel, and which 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 contains at least 90 percent biomethane content.

(3) It meets the specifications for the natural gas commercial pipeline system submitted and accepted by EPA under § 80.145(f)(6).

(4) It is used or will be used in the covered location as transportation fuel or to produce a renewable fuel.

RERG's fleet means the RERG's electric and plug-in hybrid electric LDV/T fleet.

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 generation agreement means the exclusive, bilateral, contracted ability of a RERG to generate RINs for all of the renewable electricity generated at a renewable electricity generation facility.

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 § 80.140.

RNG producer means any person who owns, leases, operates, controls, or supervises an RNG production facility.

RNG production facility means a location where biogas is upgraded to RNG.

RNG RIN separator means any person registered to separate RINs for RNG under § 80.140(d).

RNG used as a feedstock means any RNG used to produce renewable fuel (including renewable electricity) under § 80.140.

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 (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 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.

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 biogas that has undergone treatment to remove inert gases or impurities and is used in a biogas closed distribution system.

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.

Vehicle fuel economy means the average kWh consumed per mile by an EV or PHEV when operating in all electric mode.

Verification status means a description of whether biogas, renewable electricity, 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. Revise § 80.3 to read as follows:

§ 80.3 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 National Standards Institute (ANSI), 25 West 43rd Street, 4th Floor, New York, NY 10036; (212) 642–4980; *www.ansi.org.*

(1) ANSI C12.20–2015, Electricity Meters 0.1, 0.2, And 0.5 Accuracy Classes, February 17, 2017 (ANSI C12.20); IBR approved for § 80.165(c).

(2) [Reserved]

(b) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001–5571; (202) 682–8000; *www.api.org.*

(1) API MPMS 14.1–2016, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, April 2016 (''API MPMS 14.1''); IBR approved for § 80.165(b).

(2) API MPMS 14.3.1–2012, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, September 2012 (''API MPMS 14.3.1''); IBR approved for § 80.165(a).

(3) API MPMS 14.3.2–2016, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 3—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 § 80.165(a).

(4) API MPMS 14.3.3–2021, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids-Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, November 2013 (''API MPMS 14.3.3''); IBR approved for § 80.165(a).

(5) API MPMS 14.3.4–2019, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 3—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, September 2019 (''API MPMS 14.3.4''); IBR approved for § 80.165(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 § 80.165(a).

(c) American Public Health Association (APHA), 1015 15th Street NW, Washington, DC 20005; (202) 777–2742; *https://www.standardmethods.org.*

(1) SM 2540, Solids In: Standard Methods For the Examination of Water and Wastewater, approved June 10, 2020 (''SM 2540''); IBR approved for § 80.165(d).

(2) [Reserved]

(d) 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(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 § 80.165(b).

(4) 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).

(5) 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).

(6) 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 § 80.165(b).

(7) 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 § 80.165(b).

(8) 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.

(9) 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 §§ 80.165(b); 80.1426(f); 80.1430(e).

(10) ASTM D7164–21, On-line/At-line Heating Value Determination of Gaseous Fuels by Gas Chromatography, approved April 1, 2021 (''ASTM D7164''); IBR approved for § 80.165(a).

(11) 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 § 80.165(b).

(12) ASTM E711–87 (R2004), 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).

(13) 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).

§ 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 § 80.9 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.

Subpart B—Controls and Prohibitions

§ 80.24 [Amended]

■ 7. Amend § 80.24 by, in paragraph (b), removing the text ''the Administrator'' and adding, in its place, the text ''EPA''.

■ 8. Add subpart E, consisting of §§ 80.100 through 80.195, to read as follows:

Subpart E—Biogas-Derived Renewable Fuel

Sec.
80.100 Scope and application.
80.105 Biogas producers.
80.110 Renewable electricity generators.
80.115 Renewable electricity RIN generators.
80.120 RNG producers, RNG importers, and biogas closed distribution system RIN generators.
80.125 RNG RIN separators.
80.130 Parties that produce renewable fuel from biogas used as a biointermediate or RNG used as a feedstock.
80.135 RINs for renewable electricity.
80.140 RINs for RNG.
80.142 RINs for renewable CNG/LNG from a biogas closed distribution system.
80.145 Registration.
80.150 Reporting.
80.155 Recordkeeping.
80.160 Product transfer documents.
80.165 Sampling, testing, and measurement.
80.170 RNG importers and foreign biogas producers, RNG producers, renewable electricity generators, and RERGs.
80.175 Attest engagements.
80.180 Quality assurance program.
80.185 Prohibited acts and liability provisions.
80.190 Affirmative defense provisions.
80.195 Potentially invalid RINs.

§ 80.100 Scope and application.

(a) *Applicability.* (1) The provisions of this subpart E apply to all biogas, renewable electricity, and RNG used to produce a biogas-derived renewable fuel, and RINs generated for a biogas-derived renewable fuel.

(2) This subpart also specifies requirements for any person that engages in activities associated with the production, distribution, transfer, or use of biogas, renewable electricity, RNG, 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.* (1) RERGs must only generate RINs for renewable electricity used in vehicles in the RERG's fleet that are registered in a state in the covered location (excluding Hawaii).

(2) Only renewable electricity that is used as transportation fuel in the covered location (excluding Hawaii) is eligible for the generation of RINs for renewable electricity. Renewable electricity is deemed to be eligible for use as transportation fuel in the covered location if the renewable electricity is introduced into the conterminous electricity distribution system that serves the covered location (excluding Hawaii).

(3) 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 January 1, 2024, unless otherwise specified. Parties required to register under § 80.145 may register with EPA beginning on the effective date of the final rule.

(2) *Generation of RINs for renewable electricity.* RERGs must only generate RINs for renewable electricity produced from biogas or RNG produced on or after January 1, 2024.

(3) *Generation of RINs for RNG.* RNG producers must generate RINs for RNG produced on or after January 1, 2024, as specified in § 80.140.

(4) *Generation of RINs for renewable CNG/LNG.* (i) For biogas or RNG produced on or before December 31, 2023, biogas closed distribution system RIN generators must generate RINs for renewable CNG/LNG as specified in § 80.1426(f)(10) and (11), as applicable.

(ii) For biogas produced on or after January 1, 2024, biogas closed distribution system RIN generators must generate RINs for renewable CNG/LNG as specified in § 80.142.

(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 January 1, 2024.

§ 80.105 Biogas producers.

(a) *General requirements.* (1) Any biogas producer that produces biogas for use to produce RNG, renewable electricity, 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.

(5) The transfer and batch segregation limits specified in § 80.1476(g) do not apply.

(b) *Registration.* The biogas producer must register with EPA under §§ 80.145, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The biogas producer must submit reports to EPA under §§ 80.150 and 80.1451, as applicable.

(d) *Recordkeeping.* The biogas producer must create and maintain records under §§ 80.155 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 § 80.160.

(f) *Sampling, testing, and measurement.* (1)(i) A biogas producer must continuously measure the volume of biogas, in Btu, prior to transferring biogas outside of the biogas production facility.

(ii) A biogas producer must continuously measure the volume of biogas, in Btu, from each digester subject to § 80.1426(f)(3)(vi) prior to mixing with any other biogas.

(iii) A biogas producer with separate digesters at a biogas production facility that produces biogas qualified to be used to produce biogas-derived renewable fuel eligible to generate RINs multiple D codes must continuously measure the volume of biogas, in Btu, at all the following:

(A) At the output of each digester.

(B) As each mixture of biogas from multiple digesters leaves the facility.

(iv) A biogas producer must measure total solids and volatile solids for a representative sample of each cellulosic feedstock for each digester subject to § 80.1426(f)(3)(vi) at least once per calendar month.

(2) All sampling, testing, and measurements must be done in accordance with § 80.165.

(g) *Foreign biogas producer requirements.* A foreign biogas producer must meet all requirements that apply to a biogas producer under this part, as well as the additional requirements for foreign biogas producers specified in § 80.170.

(h) *Attest engagements.* The biogas producer must submit annual attest engagement reports to EPA under §§ 80.175 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 § 80.180.

(j) *Batches.* (1) A batch of biogas is the total volume of biogas produced at a biogas production facility under a single batch pathway for the calendar month, in Btu, as determined under paragraph (j)(3) of this section.

(2) 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.).

(3)(i) The batch volume of biogas for each batch pathway must be calculated as follows:

$$V_{BG,p} = V_{BG} * \frac{FE_p}{FE_{total}}$$

Where:

$V_{BG,p}$ = The batch volume of biogas for batch pathway p, in Btu.

V_{BG} = The total volume of biogas produced, in Btu, per paragraph (j)(3)(ii) of this section.

FE_p = Sum of feedstock energies from all feedstocks used to produce biogas under batch pathway p, in Btu, per § 80.1426(f)(3)(vi).

FE_{total} = Sum of feedstock energies from all feedstocks used to produce biogas, in Btu, per § 80.1426(f)(3)(vi).

(ii) The total volume of biogas produced must be calculated as follows:

$$V_{BG} = V_G * R$$

Where:

V_{BG} = The total volume of biogas produced, in Btu.

V_G = The total volume of gas produced at the biogas production facility for the calendar month, in Btu, as measured under § 80.165.

R = The renewable fraction of the gas produced at the biogas production facility for the calendar month. For gas produced only from renewable feedstocks, R is equal to 1. For 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).

(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) Production of renewable electricity via a biogas closed distribution system.

(iii) As a biointermediate via a biogas closed distribution system.

(iv) Production of RNG.

(2) For each biogas production facility that produces biogas in a biogas closed distribution system used to produce renewable electricity:

(i) The biogas producer must only supply biogas to a single renewable electricity generation facility.

(ii) The biogas producer must not inject biogas into a natural gas commercial pipeline system.

(3) 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 to a single renewable fuel production facility.

(4) If the biogas producer operates a municipal wastewater treatment facility digester, the biogas producer must not introduce any feedstocks into the digester that do not contain at least 75% average adjusted cellulosic content.

§ 80.110 Renewable electricity generators.

(a) *General requirements.* (1) Any renewable electricity generator that produces renewable electricity must comply with the requirements of this section.

(2) The renewable electricity generator must also comply with all other applicable requirements of this part and 40 CFR part 1090.

(3) If the renewable electricity generator meets the definition of more than one type of regulated party under this part or 40 CFR part 1090, the renewable electricity generator must comply with the requirements applicable to each of those types of regulated parties.

(4) The renewable electricity generator must comply with all applicable requirements of this part, regardless of whether the requirements are identified in this section.

(b) *Registration.* The renewable electricity generator must register with EPA under §§ 80.145, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The renewable electricity generator must submit reports to EPA under § 80.150.

(d) *Recordkeeping.* The renewable electricity generator must create and maintain records under § 80.155.

(e) *PTDs.* On each occasion when the renewable electricity generator transfers renewable electricity generation data to a RERG, the transferor must provide to the transferee PTDs under § 80.160.

(f) *Measurement.* (1)(i) A renewable electricity generator must continuously measure the volume of natural gas, in Btu, withdrawn from the natural gas commercial pipeline system.

(ii) A renewable electricity generator must continuously measure the volume of electricity, in kWh, produced at the renewable electricity generation facility.

(2) All measurements must be done in accordance with § 80.165.

(g) *Foreign renewable electricity generator requirements.* A foreign renewable electricity generator must meet all requirements that apply to a renewable electricity generator under this part, as well as the additional requirements for foreign renewable electricity generators specified in § 80.170.

(h) *Attest engagements.* The renewable electricity generator must submit annual attest engagement reports to EPA under § 80.175 using procedures specified in 40 CFR 1090.1800 and 1090.1805.

(i) *QAP.* Prior to the generation of Q–RINs for renewable electricity, the renewable electricity generator must meet all applicable requirements specified in § 80.180.

(j) *Retirement of RINs for RNG.* A renewable electricity generator that produces renewable electricity from RNG must retire RINs for RNG as specified in § 80.140.

(k) *Batches.* (1) A batch of renewable electricity is the total volume of renewable electricity produced at a renewable electricity generation facility under a single batch pathway for the calendar month, in kWh, as determined under paragraph (k)(3) of this section.

(2) The renewable electricity generator must assign a number (the ''batch number'') to each batch of renewable electricity 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.).

(3) The batch volume of renewable electricity for each batch pathway must be calculated as follows:

(i) For renewable electricity produced from biogas:

$$V_{RE,p} = V_{RE} * \frac{V_{BG,p}}{V_{BG}}$$

Where:

$V_{RE,p}$ = The batch volume of renewable electricity for batch pathway p, in kWh.

V_{RE} = The total volume of renewable electricity produced, in kWh, per paragraph (k)(3)(iii) of this section.

$V_{BG,p}$ = The total volume of biogas used to produce renewable electricity under

batch pathway p, in Btu, per § 80.105(j)(3)(i).

V_{BG} = The total volume of biogas used to produce renewable electricity, in Btu, per § 80.105(j)(3)(ii).

(ii) For renewable electricity produced from RNG:

$$V_{RE,p} = V_{RE} * \frac{RIN_{RNG,p}}{RIN_{RNG}}$$

Where:

$V_{RE,p}$ = The batch volume of renewable electricity for batch pathway p, in kWh.

V_{RE} = The total volume of renewable electricity produced, in kWh, per paragraph (k)(3)(iii) of this section.

$RIN_{RNG,p}$ = The total number of RINs for RNG that were retired by the renewable electricity generator corresponding to the volume of RNG used to produce renewable electricity under batch pathway p.

RIN_{RNG} = The total number of RINs for RNG that were retired by the renewable electricity generator corresponding to the volume of RNG used to produce renewable electricity.

(iii) The total volume of renewable electricity produced must be calculated as follows:

$$V_{RE} = (V_E - V_{EGU}) * \left(\frac{FE_{RNG}}{FE_{FS}}\right)$$

Where:

V_{RE} = The total volume of renewable electricity produced, in kWh.

V_E = The total volume of electricity produced at the renewable electricity generation facility for the calendar month, in kWh, as measured under § 80.165.

V_{EGU} = The total volume of electricity used by EGUs at the renewable electricity generation facility for the calendar month, in kWh.

FE_{RNG} = The total higher heating value of the RNG used to produce electricity, in Btu. For purposes of this equation, FE_R is equal to the number of RINs retired for RNG under § 80.140(e) for the calendar month multiplied by 85,200 Btu.

FE_{FS} = The total higher heating value of the feedstocks used to produce electricity, in Btu, as measured under § 80.165.

(l) *Limitations.* (1) For each renewable electricity generation facility, the renewable electricity generator must only produce renewable electricity from one of the following:

(i) Biogas in a biogas closed distribution system.

(ii) RNG.

(2) For each renewable electricity generation facility, the renewable electricity generator must only enter into a RIN generation agreement with a single RERG, except as specified in § 80.135(a)(1)(iii)(B).

(3) Renewable electricity produced from biogas in a biogas closed distribution system may only be used for RIN generation if biogas is the only feedstock used to produce electricity at the renewable electricity generation facility during that month.

§ 80.115 Renewable electricity RIN generators.

(a) *General requirements.* (1) Any RERG must comply with the requirements of this section.

(2) The RERG must also comply with all other applicable requirements of this part and 40 CFR part 1090.

(3) If the RERG meets the definition of more than one type of regulated party under this part or 40 CFR 1090, the RERG must comply with the requirements applicable to each of those types of regulated parties.

(4) The RERG must comply with all applicable requirements of this part, regardless of whether they are identified in this section.

(b) *Registration.* The RERG must register with EPA under §§ 80.145, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The RERG must submit reports to EPA under §§ 80.150, 80.1451, and 80.1452, as applicable.

(d) *Recordkeeping.* The RERG must create and maintain records under §§ 80.155 and 80.1454.

(e) *PTDs.* On each occasion when the RERG transfers RINs to another party, the transferor must provide to the transferee PTDs under § 80.1453.

(f) *Foreign RERG requirements.* A foreign RERG must meet all requirements that apply to a RERG under this part, as well as the additional requirements for foreign RERGs specified in § 80.170.

(g) *Attest engagements.* The RERG must submit annual attest engagement reports to EPA under §§ 80.175 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 renewable electricity, the RERG must meet all applicable requirements specified in § 80.180.

(i) *Batches.* (1) A batch of RINs for renewable electricity is the total number of RINs generated under § 80.135 for a renewable electricity generation facility under a single batch pathway for the quarter.

(2) The RERG must assign a number (the ''batch number'') to each batch of RINs as specified in § 80.1425.

§ 80.120 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 §§ 80.145, 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 §§ 80.150, 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 §§ 80.155 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 §§ 80.160 and 80.1453, as applicable.

(f) *Sampling, testing, and measurement.* (1)(i) An RNG producer must continuously measure the volume of RNG, in Btu, 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 continuously measure the volume of RNG, in Btu, 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 but does not produce RNG must continuously measure the volume of biogas, in Btu, after such upgrading has been conducted.

(2) All sampling, testing, and measurements must be done in accordance with § 80.165.

(g) *Foreign RNG producer, RNG importer, and foreign biogas closed distribution system RIN generator requirements.* (1)(i) A foreign RNG producer must meet all requirements that apply to an RNG producer under this part, as well as the additional requirements for foreign RNG producers specified in § 80.170.

(ii) A foreign RNG producer must either generate RINs under § 80.140 or enter into a contract with an RNG importer as specified in § 80.170(e).

(2) An RNG importer must meet all requirements that apply to an RNG importer specified in § 80.170(i).

(3) A foreign biogas closed distribution system RIN generator must meet all 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 § 80.170 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 §§ 80.175 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 § 80.180.

(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, 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)(i) The batch volume of RNG for each batch pathway must be calculated as follows:

$$V_{RNG,p} = V_{RNG} * \frac{FE_p}{FE_{total}}$$

Where:

$V_{RNG,p}$ = The batch volume of RNG for batch pathway p, in Btu.

V_{RNG} = The total volume of RNG produced, in Btu, per paragraph (j)(4)(ii) of this section.

FE_p = Sum of feedstock energies from all feedstocks used to produce RNG under batch pathway p, in Btu, per § 80.1426(f)(3)(vi).

FE_{total} = Sum of feedstock energies from all feedstocks used to produce RNG, in Btu, per § 80.1426(f)(3)(vi).

(ii) The total volume of RNG produced must be calculated as follows:

$$V_{RNG} = V_{NG} * R$$

Where:

V_{RNG} = The total volume of RNG produced, in Btu.

V_{NG} = The total volume of natural gas produced at the RNG production facility for the calendar month, in Btu, as measured under § 80.165.

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).

§ 80.125 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.* The RNG RIN separator must register with EPA under §§ 80.145, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The RNG RIN separator must submit reports to EPA under §§ 80.150, 80.1451, and 80.1452, as applicable.

(d) *Recordkeeping.* The RNG RIN separator must create and maintain records under §§ 80.155 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) An RNG RIN separator must continuously measure the volume of natural gas, in Btu, withdrawn from the natural gas commercial pipeline system.

(2) All measurements must be done in accordance with § 80.165.

(g) *Attest engagements.* The RNG RIN separator must submit annual attest engagement reports to EPA under §§ 80.175 and 80.1464 using procedures specified in 40 CFR 1090.1800 and 1090.1805.

§ 80.130 Parties that produce biogas-derived renewable fuel from biogas used as a biointermediate or RNG used as a feedstock.

(a) *General requirements.* (1) Any renewable fuel producer that uses biogas as a biointermediate or RNG as a feedstock to produce a biogas-derived renewable fuel 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 §§ 80.145, 80.1450, and 40 CFR part 1090, subpart I, as applicable.

(c) *Reporting.* The renewable fuel producer must submit reports to EPA under §§ 80.150, 80.1451, and 80.1452, as applicable.

(d) *Recordkeeping.* The renewable fuel producer must create and maintain records under §§ 80.155 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 §§ 80.160 and 80.1453.

(f) *Measurement.* (1) A renewable fuel producer must continuously measure the volume of biogas or natural gas, in Btu, withdrawn from the natural gas commercial pipeline system, as applicable.

(2) All measurements must be done in accordance with § 80.165.

(g) *Attest engagements.* The renewable fuel producer must submit annual attest engagement reports to EPA under §§ 80.175 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 § 80.180.

§ 80.135 RINs for renewable electricity.

(a) *General RIN generation provisions*—(1) *RIN generation agreements.* (i) Only a RERG may generate RINs for renewable electricity.

(ii) A RERG must only generate RINs for renewable electricity represented by a RIN generation agreement obtained from a registered renewable electricity generator.

(iii)(A) Except as specified in paragraph (a)(1)(iii)(B) of this section, for each renewable electricity generation facility, a renewable electricity generator must contract the RIN generation agreement to only one RERG and identify the RERG in the renewable electricity generator's registration information submitted under § 80.145.

(B) A renewable electricity generator may only change the designated RERG for RIN generation agreement for a renewable electricity generation facility once per calendar year unless EPA, in its sole discretion, allows the renewable electricity generator to change the designated RERG more frequently.

(iv) A RERG may have RIN generation agreements from multiple renewable electricity generation facilities and from multiple renewable electricity generators.

(v) A RERG must not transfer any RIN generation agreement to any other party.

(2) *RIN generation timing.* (i) A RERG must only generate RINs quarterly.

(ii) A RERG must generate RINs no later than 30 days after the end of the quarter for which they are generating the RINs.

(iii) The generation year for RINs generated for renewable electricity is the calendar year in which the renewable electricity was generated.

(3) *Renewable electricity allocation.* A RERG may allocate renewable electricity data for the generation of RINs in any manner as long all the following conditions are met:

(i) The total number of RINs generated does not exceed the total number of RINs determined under paragraph (c)(1) of this section.

(ii) The number of RINs generated under each batch pathway for a particular renewable electricity generation facility does not exceed the number of RINs determined under paragraph (c)(2) of this section.

(iii) Any unallocated renewable electricity for one quarter may not be used for RIN generation in another quarter.

(b) *Requirements for renewable electricity from biogas or RNG.* (1) Except as specified in paragraph (b)(2) of this section, RINs for renewable electricity produced from biogas or RNG may only be generated if all the following requirements are met:

(i) The biogas was produced by a biogas producer meeting the requirements specified in § 80.105, if applicable.

(ii) The RNG was produced by an RNG producer meeting the requirements specified in § 80.120, if applicable.

(iii) The renewable electricity was produced from biogas or RNG by a renewable electricity generator meeting the requirements specified in § 80.110.

(2) A RERG may generate RINs for renewable electricity regardless of whether the renewable electricity generator, biogas producer, or both have had their registration(s) accepted under § 80.145 if all the following requirements are met:

(i) The renewable electricity generator and biogas producer each submitted a registration request under § 80.145 with a third-party engineering review report to EPA on or before December 31, 2023.

(ii) Neither the biogas producer nor renewable electricity generator substantially alters their facilities after the third-party engineering review site visit.

(iii) The biogas was produced after the third-party engineering review site visit.

(iv) The renewable electricity generator entered into a RIN generation agreement with the RERG on or before December 31, 2023.

(v) The renewable electricity was produced between January 1, 2024, and April 30, 2024.

(vi) The biogas producer, renewable electricity generator, and RERG meet all applicable requirements under this subpart for the biogas, renewable electricity, and RINs.

(vii) EPA accepts the registrations for the biogas producer and renewable electricity generator on or before April 30, 2024.

(c) *RIN generation equations.* (1) The total number of RINs a RERG is eligible to generate for each quarter must be calculated as follows:

$$eRIN_Q = \frac{MIN\left(EL_{FLEET,Q} \middle| EL_{PRO,Q}\right)}{EqV_{RE}}$$

Where:

$eRIN_Q$ = The total number of RINs the RERG is eligible to generate for quarter Q.

MIN = A minimization function that takes the lesser of the two subsequent values in parentheses.

$EL_{FLEET,Q}$ = The total volume of electricity that was used by the RERG's fleet for quarter Q, in kWh, per paragraph (c)(1)(i) of this section.

$EL_{PRO,Q}$ = The total volume of renewable electricity eligible for RIN generation produced by all renewable electricity generation facilities for which the RERG has obtained RIN generation agreements for quarter Q, in kWh, per paragraph (c)(1)(ii) of this section.

EqV_{RE} = The equivalence value for renewable electricity, in kWh per RIN, per § 80.1415(b)(6).

(i) *Calculating RINs using the RERG's fleet.* The total volume of electricity that was used in the RERG's fleet for each quarter must be calculated as follows:

$$EL_{FLEET,Q} = \left(\frac{PHEV_Q * eVMT_{PHEV} * FE_{PHEV} + EV_Q * eVMT_{EV} * FE_{EV}}{QPY}\right)$$

Where:

$EL_{FLEET,Q}$ = The total volume of electricity that was used in the RERG's fleet for quarter Q, in kWh.

$PHEV_Q$ = The number of PHEVs in the RERG's fleet for quarter Q, as reported to EPA under § 80.150.

$eVMT_{PHEV}$ = The estimated annual distance traveled in the all-electric mode of an average PHEV in the RERG's fleet, in miles per year, per paragraph (c)(1)(i)(A) of this section.

FE_{PHEV} = The vehicle fuel economy for an average PHEV, in kWh per mile. For purposes of this equation, FE_{PHEV} is equal to 0.32.

EV_Q = The number of EVs in the RERG's fleet for quarter Q, as reported to EPA under § 80.150.

$eVMT_{EV}$ = The estimated annual distance traveled for an average EV, in miles per year. For purposes of this equation, $eVMT_{EV}$ is equal to 7,200.

FE_{EV} = The vehicle fuel economy for an average EV, in kWh per mile. For purposes of this equation, FE_{EV} is equal to 0.32.

QPY = The number of quarters per year. For purposes of this equation, QPY is equal to 4.

(A) The estimated annual distance traveled in the all-electric mode of an average PHEV in the RERG's fleet must be calculated as follows:

$$eVMT_{PHEV} = VMT_{PHEV} * \frac{\sum_{i=1}^{nP} n_{i,Q} UF_i}{\sum_{i=1}^{nP} n_{i,Q}}$$

Where:

$eVMT_{PHEV}$ = The estimated annual distance traveled in the all-electric mode of an average PHEV in the RERG's fleet, in miles per year.

VMT_{PHEV} = The estimated annual distance traveled for an average PHEV, in miles per year. For purposes of this equation, VMT_{PHEV} equals 11,500.

nP = The number of PHEV groups with distinct make, model, model year, and trim in the RERG's fleet, as reported to EPA under § 80.150.

$n_{i,Q}$ = The number of PHEVs of a particular make, model, model year, and trim in the RERG's fleet designated with i (the ''particular PHEV'') for quarter Q, as reported to EPA under § 80.150.

UF_i = The utilization factor of the particular PHEV, per paragraph (c)(1)(i)(B) of this section.

(B) The utilization factor of a particular PHEV must be calculated as follows:

(*1*) Determine the all-electric range of the PHEV as specified in 40 CFR 600.210–12(a)(4).

(*2*)(*i*) If the all-electric range of the PHEV is less than or equal to 10 miles, then UF_i equals 0.

(*ii*) If the all-electric range of the PHEV is greater than or equal to 100 miles, then UF_i equals 0.867.

(*iii*) If the all-electric range of the PHEV is greater than 10 miles and less than 100 miles, then UF_i must be calculated as follows:

$$UF_i = 0.379 * \ln(R_{EV,i}) - 0.878$$

Where:

UF_i = The utilization factor of the PHEV.

$R_{EV,i}$ = The all-electric range of the PHEV, in miles, per 40 CFR 600.210–12(a)(4).

(ii) *Calculating RINs using quarterly renewable electricity produced.* The volume of renewable electricity eligible for RIN generation produced by each renewable electricity generation facility for which the RERG has obtained a RIN generation agreement for each batch pathway for each quarter must be calculated as follows:

$$EL_{PRO,Q,i,p} = PRO_{Q,i,p} * (1 - Loss_{LINE}) * CE$$

Where:

$EL_{PRO,Q,i,p}$ = The volume of renewable electricity eligible for RIN generation produced by renewable electricity generation facility i for batch pathway p for quarter Q, in kWh.

$PRO_{Q,i,p}$ = The volume of renewable electricity produced by renewable electricity generation facility i for batch pathway p for quarter Q, in kWh.

$Loss_{LINE}$ = The assumed fraction of renewable electricity loss from the transmission of the renewable electricity expressed as a proportion. For purposes of this equation, $Loss_{LINE}$ equals 0.053.

CE = The assumed fraction of renewable electricity retained during the charging of the EV or PHEV expressed as a proportion. For purposes of this equation, CE equals 0.85.

(2) For each quarter, the maximum number of RINs a RERG is eligible to generate under each batch pathway for a particular renewable electricity facility must be calculated as follows:

$$eRIN_{max,Q,i,p} = \frac{EL_{PRO,Q,i,p}}{EqV_{RE}}$$

Where:

$eRIN_{max,Q,i,p}$ = The maximum number of RINs that a RERG is eligible to generate under batch pathway p for renewable electricity facility i for quarter Q.

EqV_{RE} = The equivalence value for renewable electricity, in kWh per RIN, per § 80.1415(b)(6).

$EL_{PRO,Q,i,p}$ = The volume of renewable electricity eligible for RIN generation produced by renewable electricity generation facility i for batch pathway p for quarter Q, in kWh, per paragraph (c)(1)(ii) of this section.

(d) *RIN separation.* A RERG must separate RINs generated for renewable electricity under § 80.1429(b)(5)(i).

(e) *RIN retirement.* A party must retire RINs generated for renewable electricity if any of the conditions specified in § 80.1434(a) apply and must comply with § 80.1434(b).

§ 80.140 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) RINs for RNG must be transacted 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 § 80.145.

(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 § 80.165 to determine the heating value of RNG for the generation of RINs.

(6) The number of RINs generated for a batch 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 an RNG batch under batch pathway p, in gallon-RINs.

$V_{RNG,p}$ = The batch volume of RNG for batch pathway p, in Btu, per § 80.120(j)(4)(i).

EqV_{RNG} = The equivalence value for RNG, in Btu 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, must not be greater than the lesser of the total loading or unloading volume measurement for the month, in Btu, as required under § 80.165(a)(1).

(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) No party may assign any other RIN to a volume of RNG except as specified in paragraph (c)(1) of this section.

(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) A party must only separate a RIN from RNG if all the following requirements are met:

(i) The party withdrew the RNG from the natural gas commercial pipeline system.

(ii) The party produced or oversaw the production of the renewable CNG/LNG from the RNG.

(iii) The party measured the volume of RNG used to produce the renewable CNG/LNG using the procedures specified in § 80.165.

(iv) The party has the following documentation demonstrating that the volume of renewable CNG/LNG was used as transportation fuel:

(A) If the party 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 party is relying on documentation from a downstream party, all the following:

(*1*) A written contract with the downstream party for the sale or use of the renewable CNG/LNG as transportation fuel.

(*2*) Records from the downstream party demonstrating the date, location, and volume of renewable CNG/LNG sold or used as transportation fuel.

(*3*) An affidavit from the downstream party confirming that the volume of renewable CNG/LNG was used as transportation fuel and for no other purpose.

(v) The volume of RNG was only used to produce renewable CNG/LNG that is used as transportation fuel and for no other purpose.

(vi) No other party used the information in paragraphs (d)(1)(i) through (v) of this section to separate RINs for the RNG.

(2) 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.

(3) A party must only separate a number of RINs equal to the total volume of RNG (where the Btu are converted to gallon-RINs using the conversion specified in § 80.1415(b)(5)) that the party demonstrates are used as renewable CNG/LNG under paragraph (d)(1) 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) 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 would expire under § 80.1428(c) and must retire the expired, assigned RINs by March 31 of the subsequent year. For example, if an RNG producer assigns RINs for RNG in 2024, the RINs expire if they are not separated under paragraph (d) of this section by December 31, 2025, and must be retired by March 31, 2026.

(3) Any party that uses RNG as a feedstock or as process heat under § 80.1426(f)(12) or (13) must retire any assigned RINs for the volume of RNG within 5 business days of such use of the RNG.

§ 80.142 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) RINs must be transacted as specified in § 80.1452.

(b) *RIN generation.* (1) Renewable CNG/LNG producers must generate RINs using the applicable requirements for RIN generation in § 80.1426.

(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).

§ 80.145 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) Renewable electricity generators.

(3) RERGs.

(4) RNG producers.

(5) Biogas closed distribution system RIN generators.

(6) RNG RIN separators.

(7) Renewable fuel producers using biogas as a biointermediate or RNG as a feedstock.

(b) *General registration requirements*—(1) *New registrants.* (i) Except as allowed under § 80.135(b)(2), 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.* Parties registered to produce renewable CNG/LNG under an approved pathway before the effective date in § 80.100(d)(1) are deemed registered under this subpart E, except as follows:

(i) If the information in the existing registration is incorrect, the party must update their registration as specified in § 80.1450(d).

(ii) If the information in the existing registration does not meet all the requirements in § 80.145(f), then the party must update their registration to meet all requirements in § 80.145(f) by November 1, 2024.

(iii)(A) Except as specified in paragraph (b)(2)(iii)(B) of this section, the party's three-year engineering review updates must include all of the information required in paragraphs (c) through (h) of this section, as applicable.

(B) A biogas closed distribution system RIN generator 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) A biogas producer, renewable electricity generator, or RNG producer under paragraph (c), (d), or (f) of this section, respectively, must undergo all the following:

(A) A third-party engineering review as specified in § 80.1450(b)(2).

(B) A three-year engineering review update as specified in § 80.1450(d)(3).

(ii) Third-party engineering reviews 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).

(4) *Registration updates.* (i) Except as specified in § 80.1450(d)(2), 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) or (2), as applicable.

(C) A change of ownership is submitted under 40 CFR 1090.820.

(ii) Information specified in paragraphs (d)(4)(ii) and (i) of this section must be updated according to the schedule 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 paragraphs (b) and (i) of this section, a biogas producer must submit all the following information for each biogas production facility:

(1) All applicable company and facility information under 40 CFR 1090.805.

(2) Information to establish the biogas production capacity for the biogas production facility, in Btu, including 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 biogas production facility, if available.

(ii) Documents demonstrating the biogas production facility's nameplate capacity.

(iii) Information describing the biogas production facility's electricity production for each of the last three calendar years prior to the registration submission, if available.

(3) A description of how the biogas will be used (*e.g.,* RNG, renewable CNG/LNG, or renewable electricity).

(4) Information related to biogas measurement as follows:

(i) A description of how biogas will be measured under § 80.165(a), including the specific standards that the meters are operated under.

(ii) A description of the biogas production process, including a process flow diagram that includes metering type(s) and location(s).

(iii) If the biogas producer is unable to continuously measure biogas, the biogas producer may request the approval by EPA of an alternative sampling protocol as long as the biogas producer demonstrates that the alternative sampling protocol properly measures the heating value of the biogas, as applicable.

(5) 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 the physical process from biogas production to dispensing of renewable CNG/LNG as transportation fuel, including major equipment (*e.g.,* tanks, pipelines, flares, separation equipment, compressors, and dispensing infrastructure).

(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 that is expected to use the CNG/LNG as transportation fuel.

(6) For biogas in a biogas closed distribution system used to produce renewable electricity, all the following additional information:

(i) Identifying information for the renewable electricity generator that the biogas producer will supply.

(ii) A process flow diagram of the physical process from biogas production to entering the renewable electricity generation facility, including major equipment (*e.g.,* feedstock retrieval, tanks, pipelines, flares, separation equipment, and compressors).

(iii) A description of the physical process from biogas production to entering the renewable electricity generation facility, including the biogas closed distribution system and explaining how the biogas is introduced into a biogas closed distribution system connected to the renewable electricity generation facility.

(7) For biogas used as a biointermediate, all the following additional information:

(i) All information specified in § 80.1450(b)(1)(ii)(B).

(ii) [Reserved]

(8) 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.

(9) 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).

(10) For biogas produced in a municipal wastewater treatment plant digester, all the following information:

(i) 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).

(ii) [Reserved]

(11) 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).

(12) For biogas produced in other waste digesters, all the following information:

(i) A separated MSW plan specified in § 80.1450(b)(1)(viii), as applicable.

(ii) A separated yard waste plan specified in § 80.1450(b)(1)(vii)(A), as applicable.

(iii) Crop residues information specified in § 80.1450(b)(1)(xv), as applicable.

(iv) A separated food waste plan or biogenic waste oils/fats/greases plan specified in § 80.1450(b)(1)(vii)(B), as applicable.

(v) If the waste digester simultaneously converts cellulosic and non-cellulosic feedstocks, registration information specified in § 80.1450(b)(1)(xiii)(C).

(vi) 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).

(d) *Renewable electricity generator.* In addition to the information required under paragraphs (b) and (i) of this section, a renewable electricity generator must submit all the following information for each renewable electricity generation facility:

(1) All applicable company and facility information under 40 CFR 1090.805.

(2) A description whether the renewable electricity generation facility will be using biogas or RNG to generate renewable electricity and, if using biogas, a description of their relationship to each biogas producer.

(3) Information to establish the renewable electricity generation facility's renewable electricity generation capacity, including all 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 renewable electricity generation facility, if available.

(ii) Documents demonstrating the renewable electricity generation facility's nameplate capacity.

(iii) Information describing the renewable electricity generation facility's electricity production for each of the last three calendar years prior to the registration submission, if available.

(iv) The construction date of the renewable electricity generation facility.

(4) Information related to each the renewable electricity generation facility's design, as follows:

(i) A diagram of the physical layout of the renewable electricity generation facility that identifies and assigns a unique identifier for each EGU and shows all connections to the biogas production facility and the conterminous electricity distribution system.

(ii) A description of the type, rating, electricity production capacity, manufacturer, and electrical consumption capacity of each EGU at the renewable electricity generation facility.

(iii) A description, including any applicable equations, that identifies the measurement locations on the diagram specified in paragraph (d)(4)(i) of the section and identifies other documentation that will be used to determine the volume, in kWh, and D code eligibility of renewable electricity.

(iv) A demonstration that the renewable electricity generation facility has installed measurement capabilities that meet the requirements of § 80.165(c), as applicable.

(5) Identification of the RERG that the renewable electricity generator has a RIN generation agreement as specified in § 80.135, if available.

(6) The information specified in paragraph (i) of this section.

(e) *RERG.* In addition to the information required under paragraph (b) of this section, a RERG must submit all the following information:

(1) All applicable company information under 40 CFR 1090.805.

(2) A description of the qualifying pathways.

(3) A description of the RERG's fleet by make, model, model year, and trim, representing the fleet at the time of registration, including all the following information for each vehicle:

(i) Whether the vehicle is an EV or PHEV.

(ii) For PHEVs, the all-electric range of the vehicle, in miles, as determined under § 80.135(c)(1)(i)(B)(*1*).

(iii) The total number of vehicles registered in a state in the covered location (excluding Hawaii).

(4) A description of the relationship to each renewable electricity generator from which the RERG has a RIN generation agreement under § 80.135(a)(1).

(f) *RNG producer.* In addition to the information required under paragraphs (b) and (i) of this section, an RNG producer must submit all the following information for each RNG production facility:

(1) All applicable company and facility information under 40 CFR 1090.805.

(2) All applicable information in § 80.1450(b)(5)(ii).

(3) Annual volume totals of the RNG produced, in Btu, at the RNG production facility for each of the last three calendar years.

(4) The natural gas commercial pipeline system name, location, and pipeline interconnect specifications into which the RNG will be injected.

(5) Information related to biogas and RNG measurement, as follows:

(i) A description of how biogas and RNG will be continuously measured.

(ii) Metering type(s) and location(s) must be included as part of the process flow diagram submitted under § 80.1450(b)(1)(i).

(iii) If the RNG producer is unable to continuously measure biogas, the RNG producer may request the approval by EPA of an alternative sampling protocol as long as the RNG producer demonstrates that the alternative sampling protocol properly measures the heating value of the biogas or RNG, as applicable.

(6) For RNG, information related to the RNG quality, including all the following:

(i) 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).

(ii) Documentation of any waiver provided by the natural gas commercial pipeline system for any parameter of the RNG that does not meet the pipeline specifications.

(iii) A certificate of analysis from an independent laboratory for a representative sample of the raw biogas produced at the biogas production facility as specified in § 80.165(b)(1).

(iv) A certificate of analysis from an independent laboratory for a representative sample of the RNG as specified in § 80.165(b)(1).

(v) If the RNG is blended with non-renewable natural gas 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 natural gas as specified in § 80.165(b)(1).

(vi) A summary table with the results of the certificates of analysis under paragraphs (f)(4)(iii) through (v) of this section and the pipeline specifications under paragraph (f)(4)(i) of this section converted to the same units.

(vii) Certificates of analysis, including the major and minor gas components specified in § 80.165(b)(1).

(viii) EPA may approve an RNG producer's request of an alternative analysis in lieu of the certificates of analysis required under paragraphs (f)(4)(iii) through (v) 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 parameters required by the pipeline specification.

(ix) A sampling protocol meeting the requirements in § 80.165(b)(1) that accurately represents the average composition of the biogas.

(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 § 80.140(b)(7).

(9) For a foreign RNG producer, all the following additional information:

(i) The applicable information specified in § 80.170.

(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 § 80.170(e).

(g) *RNG RIN separator.* In addition to the information required under paragraph (b) of this section, an RNG RIN separator must submit all the following information:

(1) Information specified in 40 CFR 1090.805.

(2) An initial list of locations of any dispensing stations where the RNG RIN separator supplies or intends to supply renewable CNG/LNG for use as transportation fuel.

(3) Description of process and equipment used to compress RNG into renewable CNG/LNG.

(h) *Renewable fuel producer using biogas as a biointermediate or RNG as a feedstock.* In addition to the information required under paragraph (b) of this section, a renewable fuel producer using biogas as a biointermediate or RNG as a feedstock must submit all the following:

(1) All applicable information in § 80.1450(b).

(2) For biogas, documentation demonstrating a direct connection between the biogas producer and the renewable fuel production facility.

(i) *Emissions-related information.* (1) The following parties must submit all the information specified in paragraph (i)(2) of this section for each pollutant specified in paragraph (i)(3) of this section, if available.

(i) Biogas producers, for each landfill or digester at the biogas production facility.

(ii) Renewable electricity generators, for each EGU at the renewable electricity generation facility.

(iii) RNG producers, for each RNG production facility.

(2)(i) The annual emission rate of each pollutant and a description of how the emission rate was measured or determined.

(ii) The regulatory level (*e.g.,* federal, state, local) and citation of the most stringent emission standard for each pollutant.

(iii) The emission rate or emission reduction specified by the most stringent emission standard for each pollutant.

(iv) Copies of National Pollutant Discharge Elimination System Forms 2A, 2B, and 2C.

(3)(i) *Air pollutants.* (A) Carbon dioxide.

(B) Carbon monoxide.

(C) Methane.

(D) Nitrous oxides.

(E) $PM_{2.5}$.

(F) PM_{10}.

(G) Sulfur dioxide.

(ii) *Water pollutants.* (A) Solid effluent.

(B) Liquid effluent.

(C) All pollutants that the party is required to monitor under any National Pollutant Discharge Elimination System permit.

§ 80.150 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).

(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 designated use of the biogas (*e.g.,* biointermediate, renewable electricity, renewable CNG/LNG, or RNG).

(5) The volume of the batch supplied to the downstream party, in Btu and scf, as measured under § 80.165(a).

(6) The associated pathway information, including D code, production process, and feedstock information.

(7) The EPA-issued company and facility IDs for the RNG producer, renewable electricity generator, biogas closed distribution system RIN generator, or renewable fuel producer that received the batch of the biogas.

(c) *Renewable electricity generators.* A renewable electricity generator must submit monthly reports to EPA containing all the following information for each batch of renewable electricity:

(1) Batch number.

(2) Production date (end date of the calendar month).

(3) Description of each batch or portion of a batch of biogas used to

produce the batch of renewable electricity batch, including all the following information:

(i) The biogas batch number.

(ii) The EPA-issued company and facility IDs for the biogas producer that produced the biogas.

(iii) The volume of biogas used as feedstock, in Btu, as measured under § 80.165(a).

(iv) The associated D code of the biogas.

(v) The verification status of the biogas.

(vi) The date or period that the biogas was transferred.

(4) Description of each batch or portion of a batch of RNG used to produce the batch of renewable electricity batch, including all the following information:

(i) The RNG batch number.

(ii) The EPA-issued company and facility IDs for the RNG producer that produced the RNG.

(iii) The volume of natural gas used as feedstock, in Btu, as measured under § 80.165(a).

(iv) The number of RINs retired for the RNG under § 80.140(e).

(v) The associated D code of the RNG.

(vi) The verification status of the RNG.

(vii) The date or period that the RNG was transferred.

(5) Total volume of electricity, in kWh, produced at the renewable electricity generation facility.

(6) Total volume of electricity, in kWh, used by EGUs at the renewable electricity generation facility.

(7) The EPA-issued company and facility IDs for each RERG that received the renewable electricity data representing the batch.

(8) Total volume of renewable electricity, in kWh, described in the renewable electricity data transferred to each RERG.

(d) *RERGs.* A RERG must submit quarterly reports to EPA containing all the following information:

(1) Volume of renewable electricity, in kWh, used to generate RINs for renewable electricity, including all the following information:

(i) The EPA-issued company and facility IDs for each renewable electricity generator and each renewable electricity generation facility.

(ii) For each renewable electricity generation facility, the volume of renewable electricity, in kWh, used to generate RINs for renewable electricity by D code and verification status.

(2) For quarterly RIN generation, a description of the RERG's fleet by make, model, model year, and trim, representing the fleet at the start of the quarter, including all the following information for each vehicle:

(i) Whether each vehicle is an EV or PHEV.

(ii) For PHEVs, the all-electric range of the vehicle, in miles, as determined under § 80.135(c)(1)(i)(B)(*1*).

(iii) The total number of vehicles registered in a state in the covered location (excluding Hawaii).

(3) For future adjustment of the RIN generation parameters, a description of the RERG's fleet by make, model, model year, and trim, representing the fleet at the start of the quarter, including all the following information for each vehicle for which the OEM received vehicle telematic data during the quarter:

(i) The total number of vehicles registered in a state in the covered location (excluding Hawaii).

(ii) Vehicle fuel economy, in kWh per mile.

(iii) Charging efficiency, as a percentage.

(iv) One of the following:

(A) eVMT, in average all-electric miles per vehicle.

(B) Average quarterly charging information, in kWh.

(4) All applicable information in § 80.1451(b)(1)(ii), (2), and (3).

(e) *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, produced and injected into the natural gas commercial pipeline system as measured under § 80.165.

(ii) [Reserved]

(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 volume of the batch, in Btu and scf, as measured under § 80.165(a).

(v) The associated pathway information, including D code, production process, and feedstock information.

(vi) The EPA-issued company and facility IDs for the RNG importer that will generate RINs for the batch.

(f) *Biogas closed distribution system RIN generators.* A biogas closed distribution system RIN generator must submit quarterly reports to EPA containing all the following information:

(1) The type and volume of biogas-derived renewable fuel, in Btu, produced from biogas.

(2) The total volume of biogas, in Btu, used to produce the biogas-derived renewable fuel as measured under § 80.165.

(3) The name(s) and location(s) of where the biogas-derived renewable fuel is used or sold for use as transportation fuel.

(4) The volume of biogas-derived renewable fuel, in Btu, 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).

(g) *RNG RIN separators.* An RNG RIN separator must submit quarterly reports to EPA containing all the following information:

(1) Name and location of the natural gas commercial pipeline system where the RNG was withdrawn.

(2) Volume of RNG, in Btu, withdrawn from the natural gas commercial pipeline system during the reporting period by location.

(3) Volume of renewable CNG/LNG, in Btu, produced during the reporting period.

(4) The locations where renewable CNG/LNG was dispensed as transportation fuel.

(5) The volume of renewable CNG/LNG, in Btu, dispensed as transportation fuel at each location.

(h) *Retirement of RINs for RNG.* A party that retires RINs for RNG used as a feedstock 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, 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 to produce renewable electricity or as a feedstock.

(4) For each facility, the volume of renewable electricity, in kWh, or biogas-derived renewable fuel, in Btu, produced from the withdrawn RNG.

(5) The number of RINs for RNG retired during the reporting period by D code and verification status.

§ 80.155 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 §§ 80.150, 80.175, 80.1451, and 80.1452 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 §§ 80.145, 80.170, and 80.1450 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 §§ 80.160 and 80.1453.

(iv) *Subpart M records.* Any applicable record required under § 80.1454.

(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, testing, and measurement results relied upon under § 80.165, including any results and maintenance 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 related to potentially invalid RINs under § 80.195.

(ix) *Foreign parties.* Any records related to foreign parties under § 80.170.

(2) *Length of time records must be kept.* The records required under this section and § 80.160 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 renewable electricity generator, RNG producer, or renewable fuel producer.

(2) Documents supporting the volume of biogas, in Btu and scf, produced for each batch.

(3) Documents supporting the composition and cleanup of biogas produced for each batch.

(4) Documentation supporting the use of each process heat source and supporting the amount of each source used in the production process for each batch.

(5) In addition to any applicable recordkeeping requirement for the use of renewable biomass to produce biogas under § 80.1454, information and documentation showing that the biogas came from renewable biomass.

(i) 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.

(ii) For municipal wastewater treatment 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.

(iii) For biogas produced from separated yard waste, separated food waste, or biogenic waste oils/fats/greases, documents required under § 80.1454(j)(1).

(iv) For biogas produced from separated municipal solid waste, documents required under § 80.1454(j)(2).

(6) For biogas produced in digesters simultaneously converting cellulosic and non-cellulosic feedstock, all the following:

(i) Documents for each delivery of feedstock to the biogas production facility, demonstrating the mass of each feedstock delivered, type of feedstock delivered, and name of feedstock supplier.

(ii) Process operational data for the types of data specified at registration under § 80.1450(b)(1)(xiii)(C)(*4*) or (*5*), as applicable.

(iii) Documents for each batch demonstrating volatile solids and total solids measurements of feedstocks.

(7) Copies of all records and notifications related to the identification of potentially inaccurate or non-qualifying biogas volumes under § 80.195(b).

(c) *Renewable electricity generators.* In addition to the records required under paragraph (a) of this section, a renewable electricity generator must keep all the following records:

(1) Contracts, PTDs, affidavits required under this part, and all other commercial documents with any biogas producer, RNG producer, RIN owner, or RERG, as applicable.

(2) Documents supporting the volume of biogas or natural gas (including both RNG and non-renewable natural gas), in Btu and scf, used to produce electricity in monthly increments received from any source.

(3) Documents supporting the monthly volume of electricity, in kWh, produced from biogas or natural gas (including both RNG and non-renewable natural gas).

(4) Documents supporting the process heat source for production process and the amount of each source used in the production process in a given month.

(5) Records related to continuous measurement, including types of equipment used, metering process, maintenance and calibration records, and documents supporting adjustments related to error correction.

(6) Documents supporting the volume of electricity, in kWh, used by EGUs at the renewable electricity generation facility.

(7) Documents supporting RIN retirements for RNG used to produce renewable electricity.

(8) Information and documents supporting that the renewable electricity was produced from biogas or RNG.

(9) Information and documents related to participation in any QAP program, including contracts between the renewable electricity generator and the QAP provider, records related to verification activities under the QAP, and copies of any QAP-related submissions.

(10) Copies of any applicable air permits over the past 5 years issued by EPA, a state, a local air pollution control agency, or a foreign governmental agency that governs the renewable electricity generation facility.

(d) *RERGs.* In addition to the records required under paragraph (a) of this section, a RERG 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 the renewable electricity.

(iv) Documents demonstrating the make, model, model year, and trim of all

vehicles in the RERG's fleet included in RIN generation under § 80.135.

(v) Documentation of any calculation relied upon for RIN generation.

(vi) Documentation describing how the RERG allocated renewable electricity used to generate RINs by facility, D code, and verification status.

(vii) Contracts, PTDs, affidavits, agreements required under this part, and all other commercial documents with any renewable electricity generator.

(viii) Copies of renewable electricity data received from any renewable electricity generator.

(2) All documents specified in § 80.1454(b), as applicable.

(3) Information and documentation related to participation in any QAP program, including contracts between the RERG and the QAP provider, records related to verification activities under the QAP, and copies of any QAP-related submissions.

(4) All documents supporting the values used in the calculations in § 80.135(c)(1)(i).

(e) *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 raw biogas, in Btu and scf, respectively, received at each RNG production facility.

(vi) Volume of RNG, in Btu and scf, produced at each RNG production facility.

(vii) Pipeline injection statements describing the volume of RNG, in Btu and scf, 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) Process heat source for production process.

(7) Records related to continuous measurement, including types of equipment used, metering process, maintenance and calibration records, and documents supporting adjustments related to error correction.

(8) 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.

(9) 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 § 80.140(b)(7).

(10) Summaries comparing raw biogas to treated biogas, including from certificates of analysis from independent laboratories and from meters on site.

(11) Documents supporting the amount of methane and other gases released into the atmosphere at the facility.

(f) *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.

(g) *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, withdrawn from the natural gas commercial distribution system.

(2) Documentation demonstrating that RNG withdrawn from the natural gas commercial distribution system was used to produce renewable CNG/LNG.

(3) Documentation indicating the volume of renewable CNG/LNG, in Btu, dispensed as transportation fuel from each dispensing location.

(4) Copies of all documentation required under § 80.140(d)(1)(iv), as applicable.

(h) *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) Documentation supporting the volume of biogas, in Btu and scf, that was used as a biointermediate from each biointermediate production facility.

(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, withdrawn from the natural gas commercial distribution system.

(ii) Documentation supporting the retirement of RINs for RNG used as a feedstock (*e.g.,* contracts, purchase orders, invoices).

(j) *RNG importers and non-RIN generating foreign RNG producers.* In addition to the records required under paragraph (a) of this section, an RNG importer or non-RIN generating foreign RNG producer must keep all the following records:

(1) Copies of all reports submitted under § 80.170(i)(2).

(2) [Reserved]

§ 80.160 Product transfer documents.

(a) *General requirements*—(1) *PTD contents.* On each occasion when any person transfers title of any biogas, renewable electricity data, 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 for biogas and RNG and kWh for renewable electricity data) 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 as renewable electricity, ''This volume of biogas is designated and intended for use to produce renewable electricity.''

(ii) 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.''

(iii) For biogas designated for use to produce RNG, ''This volume of biogas is designated and intended for use to produce renewable natural gas.''

(iv) For biogas designated for use as a biointermediate, the applicable language found at § 80.1453(f)(1)(vi).

(v) For biogas designated for use as process heat under § 80.1426(f)(12), ''This volume of biogas is designated and intended for use as process heat.''

(c) *PTD requirements for custodial transfers of RNG.* Whenever 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)(1) 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.* Whenever custody 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)(1) 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 § 80.170(e).

(4) The name, EPA-issued company and facility IDs, and address of the transferee.

§ 80.165 Sampling, testing, and measurement.

(a) *Biogas and RNG continuous measurement.* Any party required to continuously measure the volume of biogas or RNG under this subpart must use all the following:

(1) In-line GC meters compliant with ASTM D7164 (incorporated by reference, see § 80.3), 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 § 80.3).

(ii) API MPMS 14.12 (incorporated by reference, see § 80.3).

(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 § 80.3).

(2) Perform all the following measurements on each representative sample:

(i) Methane, carbon dioxide, nitrogen, and oxygen using EPA Method 3C.

(ii) Hydrogen sulfide and total sulfur using ASTM D5504 (incorporated by reference, see § 80.3).

(iii) Siloxanes using ASTM D8230 (incorporated by reference, see § 80.3).

(iv) Moisture using ASTM D4888 (incorporated by reference, see § 80.3).

(v) Hydrocarbon analysis using EPA Method 18.

(vi) Heating value and relative density using ASTM D3588 (incorporated by reference, see § 80.3).

(vii) Additional components specified in pipeline specifications or specified by EPA as a condition of registration under § 80.145 or § 80.1450.

(viii) Carbon-14 analysis using ASTM D6866 (incorporated by reference, see § 80.3).

(c) *Renewable electricity.* Any party required to continuously measure the volume of renewable electricity under this subpart must use ANSI C12.20 (incorporated by reference, see § 80.3).

(d) *Digester feedstock.* Any party required to measure total solids and volatile solids of a digester feedstock under this subpart must use Part G of SM 2540 (incorporated by reference, see § 80.3).

(e) *Third parties.* Samples required to be obtained under this subpart may be collected and analyzed by third parties.

§ 80.170 RNG importers and foreign biogas producers, RNG producers, renewable electricity generators, and RERGs.

(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 § 80.170(b)(4) and (c) as part of their registration under § 80.145.

(2) *Bond posting.* A foreign party that generates RINs must meet the 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 § 80.140.

(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 § 80.155.

(*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.

(g) *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 (c)(1) 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.

(h) *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 80.170, 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.''

(i) *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, injected into the natural gas commercial pipeline system as specified in § 80.165.

(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 (h) of this section.

(ii) The name of the foreign non-RIN generating RNG producer, containing the information specified in paragraph (h) 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, 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 (i)(1) and (2) of this section for five years from the date of creation.

§ 80.175 Attest engagements.

(a) *General provisions.* (1) The following parties must arrange for annual attestation engagement using agreed-upon procedures:

(i) Biogas producers.

(ii) Renewable electricity generators.

(iii) RERGs.

(iv) RNG producers.

(v) RNG importers.

(vi) Biogas closed distribution system RIN generators.

(vii) RNG RIN separators.

(viii) 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, renewable electricity generation 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 the biogas producer's registration information submitted under §§ 80.145 and 80.1450 and all reports submitted under §§ 80.150 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) Report the date of the last engineering review conducted under §§ 80.145(b)(3) and 80.1450(b), as applicable. 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 §§ 80.150 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 as follows:

(i) Obtain records related to measurement under § 80.155(a)(1)(vi).

(ii) Identify and report the name of the method(s) used for measuring the volume of biogas, in Btu and in scf, and report as a finding any method that is not specified in § 80.165 or the biogas producer's registration.

(iii) Identify whether maintenance and calibration records were kept and 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 § 80.150.

(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 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 § 80.160 and report as a finding any exceptions.

(c) *General procedures for renewable electricity generators.* An attest auditor must conduct annual attestation audits for renewable electricity generators using the following procedures:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of the renewable electricity generator's registration information submitted under § 80.145 and all reports submitted under § 80.150.

(ii) For each renewable electricity generation 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) Report the date of the last engineering review conducted under § 80.145(b)(3). 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 renewable electricity generator submitted all reports required under § 80.150 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 or RNG received as follows:

(i) Obtain copies of records documenting the source and volume of biogas or RNG, in Btu and scf, received by the renewable electricity generator. Report the number of parties the renewable electricity generator received biogas or RNG from and the total volume of biogas or RNG, in Btu and scf, received separately from each party.

(ii) Obtain copies of records showing the volume of biogas or RNG, in Btu and scf, used to produce renewable electricity. Report as a finding the total volume of biogas or RNG, in Btu and scf, used to produce renewable electricity.

(iii) Obtain copies of records showing whether non-renewable feedstocks were used to produce renewable electricity. Report as a finding if any RINs were generated for electricity produced from the non-renewable feedstocks.

(3) *Measurement method review.* The auditor must review measurement methods as follows:

(i) Obtain records related to measurement under § 80.155(a)(1)(vi).

(ii) Identify and report the name of the method(s) used for measuring the volume of renewable electricity, in kWh, and report as a finding any method that is not specified in § 80.165 or the renewable electricity generator'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 § 80.150.

(ii) Compare the reported volume for each batch to the measured volume and report as a finding any exceptions.

(5) *Testing of renewable electricity data transfers.* The auditor must review renewable electricity data transfers as follows:

(i) Obtain the associated PTD for each batch of renewable electricity 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 kWh, 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 § 80.160 and report as a finding any exceptions.

(5) *Renewable electricity batches from RNG.* If RNG was used to produce renewable electricity, the auditor must review renewable electricity batches as follows:

(i) Obtain copies of records demonstrating the number and types of RINs retired for RNG under § 80.140(e).

(ii) Verify that the proper volume of renewable electricity was produced under § 80.110(k)(3) for each batch as follows:

(A) Calculate the total volume of renewable electricity the renewable electricity generator is eligible to produce for the month using the equations in § 80.110(k)(3). Compare this value to the batch report and report as a finding any difference.

(B) Calculate the maximum volume of renewable electricity the renewable electricity generator is eligible to produce for the month using the equations in § 80.110(k)(3). Compare this value to the batch report and report as a finding if the maximum volume of renewable electricity was less than the volume of renewable electricity produced.

(d) *General procedures for RERGs.* An attest auditor must conduct annual attestation audits for RERGs using the following procedures:

(1) *Registration and EPA reports.* The auditor must review registration and EPA reports as follows:

(i) Obtain copies of the RERG's registration information submitted under § 80.145 and all reports submitted under § 80.150.

(ii) Confirm that the RERG'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 RERG submitted all reports required under §§ 80.150 and 80.1451 for activities performed during the compliance period and report as a finding any exceptions.

(2) *Renewable electricity RIN generation.* The auditor must perform the following procedures for quarterly RIN generation:

(i) Obtain copies of all the following:

(A) PTDs containing the renewable electricity data provided to the RERG under § 80.160(a)(1)(iii).

(B) Records used to calculate the RERG's fleet under §§ 80.150(d)(2)(i) and (iii).

(C) Records used to calculate the electric range of PHEVs by make, model, model year, and trim under § 80.150(d)(2)(ii).

(D) RIN generation information submitted under § 80.1452.

(ii) Using the values obtained in paragraph (d)(2)(i) of this section, verify that the proper number of RINs were generated under § 80.135 for each batch as follows:

(A) Calculate the total number of RINs the RERG is eligible to generate for the quarter using the equations in § 80.135(c)(1). Compare this value to the number of RINs the RERG generated for the quarter and report as a finding any difference.

(B) Calculate the maximum number of RINs the RERG is eligible to generate for the quarter using the equations in § 80.135(c)(2). Compare this value to the number of RINs the RERG generated for the quarter and report as a finding if the maximum number of RINs was less than the number of RINs generated.

(e) *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 the RNG producer or importer's registration information submitted under §§ 80.145 and 80.1450 and all reports submitted under §§ 80.150 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) Report the date of the last engineering review conducted under §§ 80.145(b)(3) and 80.1450(b), as applicable. 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 §§ 80.150 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 records documenting the source and volume of biogas, in Btu and scf, received by the RNG producer. Report the number of parties the RNG producer received biogas from and the total volume received separately from each party.

(ii) Obtain copies of records showing the volume of biogas, in Btu and scf, used to produce RNG. Report the total volume of biogas used to produce RNG, in Btu and scf, and report as a finding if the volume of RNG is greater than the volume of biogas.

(iii) Obtain copies of records showing whether non-renewable components were blended into RNG. 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 as follows:

(i) Obtain records related to measurement under § 80.155(a)(1)(vi).

(ii) Identify and report the name of the method(s) used for measuring the volume of RNG, in Btu and in scf, and report as a finding any method that is not specified in § 80.165 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 § 80.150.

(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 pipeline specifications.

(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 § 80.160 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.

(f) *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 the biogas closed distribution system RIN generator's registration information submitted under § 80.145 and all reports submitted under § 80.150.

(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 §§ 80.150 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.

(g) *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 the RNG RIN separator's registration information submitted under §§ 80.145 and 80.1450 and all reports submitted under §§ 80.150 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 §§ 80.150 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 records required under § 80.155(g).

(ii) Compare the volume of RNG, in Btu, withdrawn from the natural gas commercial distribution system to the reported volume of RNG, in Btu, used to produce the renewable CNG/LNG.

(iii) Compare the volume of CNG/LNG sold or used as transportation fuel to the reported volume of CNG/LNG separated from RINs.

(iv) Report as a finding if the volume of CNG/LNG sold or used as transportation fuel does not match the volume of CNG/LNG separated from RINs.

(3) *RIN owner.* The auditor must complete all requirements specified in § 80.1464(c).

(h) *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 the renewable fuel producer's registration information submitted under § 80.145 and all reports submitted under § 80.150.

(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 §§ 80.150 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 §§ 80.150(h) and 80.1452.

(B) Records related to measurement under § 80.155(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.

§ 80.180 Quality assurance program.

(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 electricity produced in a biogas closed distribution system, the biogas producer, the renewable electricity generator, and the RERG.

(iii) For renewable electricity produced from RNG, the renewable electricity generator and the RERG.

(iv) For renewable CNG/LNG produced from RNG, the biogas producer and the RNG producer.

(v) 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.

(vi) 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.

(vii) 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) and (g) through (h).

(3) QAPs approved by EPA to verify RINs generated under this subpart must meet the requirements in § 80.1469(c) through (f), as applicable.

(4) Independent third-party auditors must conduct quality assurance audits at biogas production facilities, RNG production facilities, renewable electricity generation 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(a) and (b)(3), as applicable.

(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 producers.* In addition to the elements verified under § 80.1469(c) through (f), the independent third-party auditor must do all the following at each biogas production facility:

(1) Verify that the measurement of biogas is consistent with the requirements in § 80.165.

(2) Verify that the PTDs for biogas transfers are consistent with the applicable PTD requirements in §§ 80.160 and 80.1453.

(c) *Requirements for RNG producers.* In addition to the elements verified under § 80.1469(c) through (f), the independent third-party auditor must do all the following at each RNG production facility:

(1) Verify that the sampling, testing, and measurement of RNG is consistent with the requirements in § 80.165.

(2) Verify that RINs were assigned consistent with § 80.140(c).

(3) Verify that RINs were separated and retired consistent with § 80.140(d) and (e), respectively.

(4) Verify that the RNG was injected into a natural gas commercial pipeline system.

(5) 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 electricity generators.* In addition to the elements verified under § 80.1469(c) through (f), the independent third-party auditor must do all the following at each renewable electricity generation facility:

(1) Verify that the measurement of renewable electricity is consistent with the requirements in § 80.165(c).

(2) Verify that RIN generation agreement is contracted consistent with the requirements in § 80.135(a)(1).

(3) Verify that the renewable electricity was only produced from biogas or RNG consistent with an approved pathway.

(4) Verify that the renewable electricity data is consistent with the volume specified on the PTD to the RERG under § 80.160(c).

(5) Verify that the renewable electricity generator retired RINs for RNG used to produce renewable electricity consistent with § 80.140(e).

(e) *Requirements for RERGs.* The independent third-party auditor must verify that each input in the equations in § 80.135 is properly calculated.

(f) *Requirements for renewable fuel producers using biogas as a biointermediate.* The independent third-party auditor must meet all requirements specified in paragraph (b) of this section and § 80.1477.

(g) *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).

§ 80.185 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 (5) of this section is liable for any violation of any prohibition under 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 § 80.190.

(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 or RNG produced from the biogas to produce a biointermediate.

(iv) Any person that used the biogas, RNG produced from the biogas, or biointermediate produced from the biogas or RNG 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.

(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 biointermediate producer that used the RNG to produce a biointermediate.

(iv) Any person that used the RNG or biointermediate produced from the RNG to produce a biogas-derived renewable fuel.

(v) Any person that generated a RIN from a biogas-derived renewable fuel produced from the RNG or biointermediate produced from the RNG.

(4) *Renewable electricity liability.* When renewable electricity 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) Any biogas producer that produced the biogas used to generate the renewable electricity.

(ii) Any RNG producer that produced RNG used to produce renewable electricity.

(iii) The renewable electricity generator that generated the renewable electricity.

(iv) Any RERG that generated a RIN from the renewable electricity.

(5) *RINs generated for renewable electricity liability.* When RINs generated for renewable electricity are found in violation of a prohibition specified in paragraph (a) of this section or § 80.1460, the following persons are deemed in violation:

(i) Any biogas producer that produced the biogas used to generate the renewable electricity for which the RINs were generated.

(ii) Any RNG producer that produced RNG used to produce renewable

electricity for which the RINs were generated.

(iii) Any renewable electricity generator that generated the renewable electricity for which the RINs were generated.

(iv) The RERG that generated the RIN.

(6) *Third-party liability.* Any party allowed under § 80.165(e) 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.

§ 80.190 Affirmative defense provisions.

(a) *Applicability.* A person may establish an affirmative defense to a violation that person is liable for under § 80.185(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 § 80.185(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 § 80.185(b)(1) and (3).

(4) A person that is a renewable electricity generator may not establish an affirmative defense under this section for a violation that the renewable electricity generator is liable for under § 80.185(b)(1) and (4).

(b) *General elements.* A person may only establish an affirmative defense under this section if the person meets all of 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, RNG, renewable electricity, or RINs were 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 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 QAP that includes, at a minimum, a periodic sampling and testing 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 §§ 80.180 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 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 QAP that includes, at a minimum, a periodic sampling and testing 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 §§ 80.180 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.

(e) *Renewable electricity generator elements.* In addition to the elements in paragraph (b) of this section, a renewable electricity generator must also meet all the following requirements to establish an affirmative defense:

(1) The renewable electricity generator conducted or arranged to be conducted a QAP that includes, at a minimum, a periodic sampling and testing program adequately designed to ensure that the biogas or RNG used to generate their renewable electricity meets the applicable requirements to produce biogas or RNG under this part.

(2) The renewable electricity generator only generated renewable electricity from biogas or RNG verified by a third-party auditor under an approved QAP under §§ 80.180 and 80.1469.

(3) The PTDs for the biogas or RNG used to produce their renewable electricity indicate that the biogas or RNG was in compliance with the applicable requirements.

§ 80.195 Potentially invalid RINs.

(a) *Identification and treatment of potentially invalid RINs (PIRs).* (1) Any RIN can be identified as a PIR by the RIN generator, an 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), as applicable.

(b) *Potentially inaccurate or non-qualifying volumes of biogas-derived renewable fuel.* (1) Any party that becomes aware of potentially inaccurate or non-qualifying volumes of biogas-derived renewable fuel 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 § 80.180, the party must notify the independent third-party auditor within 5 business days.

(iii) Non-RIN generating foreign RNG producers must follow 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 inaccurate or non-qualifying volumes of biogas-derived renewable fuel under paragraph (b)(1) of this section must correct affected volumes of biogas-derived renewable fuel under paragraph (a)(2) of this section, as applicable.

(3) Any notified party that generates RINs must use the procedures specified in § 80.1474(b) for identification and treatment of PIRs and retire any PIRs under § 80.1434(a), as applicable.

(c) *Potentially inaccurate volumes of renewable electricity.* (1) When a renewable electricity generator becomes aware of inaccurate quantities of renewable electricity produced and transferred to the RERG, the renewable electricity generator must notify EPA and the RERG within 5 business days of initial discovery.

(2) The RERG must then calculate any impacts to the number of RINs generated for the volume of impacted renewable electricity. The RERG must then notify EPA and the independent third-party auditor, if any, within 5 business days of initial notification.

(3) For any number of RINs over-generated based off the inaccurate volumes of renewable electricity, the RERG must retire these RINs or replacement RINs as specified in § 80.1434(a)(9).

(d) *Potential double counting of volumes of biogas or RNG.* (1) When a renewable electricity generator, RERG, or any other party becomes aware of a biogas or RNG producer taking credit for the same volume of biogas or RNG sold to multiple renewable electricity generators, or of a renewable electricity generator taking credit for the same volume of renewable electricity sold to multiple RERGs, they must notify EPA within 5 business days of initial discovery.

(2) The RERG must then calculate any impacts to the number of RINs generated for the volume of impacted renewable electricity. The RERG must then notify EPA and the independent third-party auditor, if any, within 5 business days of initial notification.

(3) For any number of RINs over-generated based off the double counting of volumes of biogas or RNG, the RERG must retire these RINs or replacement RINs as specified in § 80.1434(a)(9).

(e) *Failure to take corrective action.* Any person who fails to meet a requirement under paragraphs (b), (c), or (d) 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.

(f) *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.

(g) *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

■ 9. Revise § 80.1402 to read as follows:

§ 80.1401 Definitions.

The definitions of § 80.2 apply for the purposes of this Subpart M.

§ 80.1402 [Amended]

■ 10. Amend § 80.1402 by, in paragraph (f), removing the text ''notwithstanding'' and adding, in its place, the text ''regardless of''.

■ 11. 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
2022	0.35	2.33	3.16	11.59	0.14
2023	0.41	2.54	3.33	11.92	0.14
2024	0.82	2.60	3.80	12.55	n/a
2025	1.23	2.67	4.28	13.05	n/a

* * * * *

(c) EPA will calculate the annual renewable fuel percentage standards using the following equations:

$$Std_{CB,i} = 100 * \frac{RFV_{CB,i}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$Std_{BBD,i} = 100 * \frac{RFV_{BBD,i} \times 1.57}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$Std_{AB,i} = 100 * \frac{RFV_{AB,i}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$Std_{RF,i} = 100 * \frac{RFV_{RF,i}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

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.

* * * * *

■ 12. 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]

■ 13. 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''.

■ 14. Amend § 80.1415 by:

■ a. In paragraph (b)(2), removing the text ''(mono-alkyl ester)'';

■ b. Revising paragraphs (b)(5) through (7);

■ c. In paragraph (c)(1), revising the definition of ''R'';

■ d. In paragraph (c)(2)(ii), removing the text ''derived'' and adding, in its place, the text ''produced''; and

■ e. In paragraph (c)(5), removing the text ''the Administrator'' and adding, in its place, the text ''EPA''.

The revision reads as follows:

§ 80.1415 How are equivalence values assigned to renewable fuel?

* * * * *

(b) * * *

(5) 77,000 Btu (lower heating value) of renewable CNG/LNG or RNG shall represent one gallon of renewable fuel with an equivalence value of 1.0.

(6)(i) For renewable electricity produced from biogas or RNG, 6.5 kW-hr of electricity shall represent one gallon of renewable fuel with an equivalence value of 1.0.

(ii) For renewable electricity produced from renewable biomass other than biogas or RNG, 22.6 kW-hr of electricity 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. Except for renewable electricity, a producer or importer may also submit an application for an alternative equivalence value pursuant to paragraph (c) of this section if the renewable fuel is listed in this paragraph (b), but the producer or importer has reason to believe that a different equivalence value than that listed in this paragraph (b) is warranted.

(c) * * *

(1) * * *

R = Renewable content of the renewable fuel. This is a measure of the portion of a renewable fuel that came from renewable biomass, expressed as a fraction, on an energy basis. For co-processed fuel, R is equal to 1.0.

* * * * *

§ 80.1416 [Amended]

■ 15. 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''.

■ 16. Amend § 80.1426 by:

■ a. Revising paragraph (a)(1) introductory text;

■ b. In paragraph (a)(1)(iv), removing the text ''renewable'';

■ c. Revising paragraphs (a)(4), (b)(1), and (c)(1) and (2);

■ d. Removing and reserving paragraph (c)(3);

■ e. In paragraph (c)(7), removing the text ''§ 80.1401'' and adding, in its place, the text ''§ 80.2'';

■ f. Adding a sentence to the end of paragraph (d)(1) introductory text;

■ g. Revising paragraphs (e)(1) and (f)(1)(i);

■ h. Moving Table 1 to § 80.1426 and Table 2 to § 80.1426 immediately following paragraph (f)(1) to the end of the section;

■ i. 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'';

■ j. 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'';

■ k. Revising paragraph (f)(3)(v);

■ l. Removing Table 3 to § 80.1426 immediately following paragraph (f)(3)(v);

■ m. Revising paragraph (f)(3)(vi);

■ n. Removing Table 4 to § 80.1426 immediately following paragraph (f)(3)(vi)(A);

■ o. Revising paragraph (f)(4);

■ p. In paragraph (f)(5)(v), removing the text ''biogas-derived fuels'' and adding, in its place, the text ''biogas-derived renewable fuel'';

■ q. 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'';

■ r. Revising paragraphs (f)(6) introductory text and (f)(7)(i), (f)(7)(v)(A) and (B);

■ s. In paragraph (f)(8)(ii) introductory text, removing the text ''(mono-alkyl esters)'';

■ t. Revising paragraphs (f)(8)(ii)(B), (f)(9)(i) and (ii), (f)(10) through (13), (f)(15), (f)(17), and (g)(1)(i) introductory text;

■ u. 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'';

■ v. Revising paragraph (g)(2) introductory text; and

■ w. 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 of the following occur:

* * * * *

(4) For co-processed fuel, RINs may only be generated for the portion of fuel that is produced from renewable biomass, as calculated under paragraph (f)(4) of this section.

(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.

* * * * *

(d) * * *

(1) * * * Biogas producers, RNG producers, and RERGs must use the definition of batch for biogas, RNG, and renewable electricity in §§ 80.105(j), 80.120(j), and 80.110(k), 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.

$$V_{RIN,DX} = EV_{DX} * V_{S,DX}$$

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.

EV_{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:

$$V_{RIN,DX} = EV * V_S * \frac{FE_{DX}}{FE_{total}}$$

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.

EV = 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} = Sum of feedstock energies from all feedstocks whose pathways have been assigned a D code of X, in Btu, per paragraphs (f)(3)(vi)(B) through (D) of this section.

FE_{total} = Sum of feedstock energies from all feedstocks, in Btu, per paragraphs (f)(3)(vi)(B) through (D) 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.

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/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 from advanced feedstocks, the feedstock energy value for advanced feedstocks must be calculated as follows:

$FE_{D5} = FE_{BG} - FE_{D3/7}$

Where:

FE_{D5} = Sum of feedstock energies from all feedstocks whose pathways have been assigned a D code of 5, in Btu. If the result of this equation is negative, then FE_5 equals 0.

FE_{BG} = Biogas energy in higher heating value produced by the digester, in Btu, as measured under § 80.165(a).

$FE_{D3/7}$ = Sum of feedstock energies from all feedstocks whose pathways have been assigned a D code of 3 or 7, in Btu, per paragraph (f)(3)(vi)(D) of this section.

(D) For biogas produced from anaerobic digestion from cellulosic feedstocks, the feedstock energy value for each cellulosic feedstock must be calculated as follows:

$FE_{D3/7,i} = M_i * TS_i * VS_i * CF_i$

Where:

$FE_{D3/7,i}$ = The amount of energy from feedstock i that forms energy in the renewable fuel and whose pathway has been assigned a D code of 3 or 7, in Btu.

M_i = Mass of feedstock i, in pounds, measured on a daily or per-batch basis.

TS_i = Total solids of feedstock i, as a mass fraction, in pounds total solids per pound feedstock, per § 80.165(d), measured on a daily or per-batch basis.

VS_i = Volatile solids of feedstock i, as a mass fraction, in pounds volatile solids per pound total solids, per § 80.165(d), measured on a daily or per-batch basis.

CF_i = Converted fraction in annual average Btu/lb, representing the portion of feedstock i that is converted to biomethane from the cellulosic feedstock by the producer. If the anaerobic digester was operated outside of the applicable operating conditions specified in § 80.1450(b)(1)(xiii)(C)(4) or (5), CF_i for that batch equals 0.

(4) *Co-processed fuel and intermediate.* (i) For a batch of co-processed fuel (excluding biodiesel, RNG, and renewable electricity), the RIN generator must determine the number of gallon-RINs (*i.e.,* V_{RIN}) that may be generated using one of the following approaches:

(A) *Approach A.* (*1*) This approach must only be used for a process that meets all the following requirements:

(*i*) The renewable fuel is produced under approved pathways with a single D code.

(*ii*) The fraction of carbon in the co-processed fuel that originates from renewable biomass does not exceed the fraction of chemical energy in the co-processed fuel that originates from renewable biomass.

(*2*) V_{RIN} must be calculated as follows:

$V_{RIN} = EqV * V_f * R$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs generated for the batch of renewable fuel.

EqV = Equivalence value of the renewable fuel, per § 80.1415.

V_f = Standardized volume of the batch of co-processed fuel at 60 °F, in gallons, per paragraph (f)(8) of this section.

R = The renewable fraction of the co-processed fuel as measured by a carbon-14 dating test method, per paragraph (f)(9) of this section.

(B) *Approach B.* (*1*) This approach must only be used for a process that meets all the following requirements:

(*i*) The process does not meet the requirements of Approach A in paragraph (f)(4)(i)(A) of this section.

(*ii*) Neither heat nor electricity is converted to chemical energy in the co-processed fuel.

(*iii*) The fraction of chemical energy in the co-processed fuel that comes from renewable biomass is equal to or greater than the fraction of chemical energy in the feedstocks that comes from renewable biomass.

(*iv*) If the renewable fuel produced is eligible to generate both D3/D7 RINs and D4/D5/D6 RINs, the fraction of chemical energy in the co-processed fuel eligible to generate D3/D7 RINs that comes from renewable biomass is equal to or greater than the fraction of chemical energy in the feedstocks qualified to be used to produce renewable fuel eligible to generate D3/D7 RINs that comes from renewable biomass.

(*v*) If the renewable fuel produced is eligible to generate both D4/D5 RINs and D6 RINs, the fraction of chemical energy in the co-processed fuel eligible to generate D4/D5 RINs that comes from renewable biomass is equal to or greater than the fraction of chemical energy in the feedstocks qualified to be used to produce renewable fuel eligible to generate D4/D5 RINs that comes from renewable biomass.

(*2*) V_{RIN} must be calculated as follows:

$V_{RIN,DX} = EqV * V_f * FE_{R,DX}/(FE_R + FE_{NR})$

Where:

$V_{RIN,DX}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs generated for the batch of renewable fuel with D code of X.

EqV = Equivalence value of the renewable fuel, per § 80.1415.

V_f = Standardized volume of the batch of co-processed fuel at 60 °F, in gallons, per paragraph (f)(8) of this section.

$FE_{R,DX}$ = Sum of feedstock energies from renewable biomass (including the renewable portion of a biointermediate) used to make the co-processed fuel that qualify be used to produce renewable fuel with D code of X, in Btu, per paragraph (f)(4)(i)(B)(*3*) of this section.

FE_R = Sum of feedstock energies from all renewable biomass (including the renewable portion of a biointermediate) used to make the co-processed fuel, in Btu, per paragraph (f)(4)(i)(B)(*3*) of this section.

FE_{NR} = Sum of feedstock energies from all non-renewable feedstocks (including the non-renewable portion of a biointermediate) used to make the co-processed fuel, in Btu, per paragraph (f)(4)(i)(B)(*3*).

(*3*) The feedstock energy value for each feedstock must be calculated as follows:

$FE_i = M_i * (1 - m_i) * E_i$

Where:

FE_i = Feedstock energy of feedstock i, in Btu.

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.

E_i = Energy content of feedstock i, in annual average Btu/lb, per paragraph (f)(7) of this section.

(C) *Approach C.* (*1*) This approach must only be used for a process that meets all the following requirements:

(*i*) The process does not meet the requirements of Approach A or B in paragraphs (f)(4)(i)(A) and (B) of this section.

(*ii*) Heat or electricity is converted to energy in the co-processed fuel.

(*2*) V_{RIN} must be calculated as follows:

$$V_{RIN,DX} = EqV * \frac{E_{RB,DX}}{ED}$$

Where:

$V_{RIN,DX}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs generated for the batch of renewable fuel with D code of X.

EqV = Equivalence value of the renewable fuel, per § 80.1415.

$E_{RB,DX}$ = The chemical energy in the batch of co-processed fuel that came from chemical energy in renewable biomass qualified to be used to produce renewable fuel with D code of X, in Btu, per paragraph (f)(4)(i)(C)(*3*) of this section.

ED = The energy density of the renewable fuel, in Btu per gallon.

(*3*) $E_{RB,DX}$ must be calculated as follows:

$E_{RB,DX} = E_{feedstock,DX} - E_{exo,DX} - E_{other,DX} + E_{endo,DX}$

Where:

$E_{RB,DX}$ = The chemical energy in the batch of co-processed fuel that came from chemical energy in renewable biomass qualified to be used to produce renewable fuel with D code of X, in Btu.

$E_{feedstock,DX}$ = The total chemical energy from renewable biomass qualified to be used to produce renewable fuel with D code of X used to produce the batch of co-processed fuel, in Btu, per paragraph (f)(7) of this section.

$E_{exo,DX}$ = The total chemical energy from renewable biomass qualified to be used to produce renewable fuel with D code of X that is converted to heat during the production of the batch of co-processed fuel, in Btu.

$E_{other,DX}$ = The total chemical energy from renewable biomass qualified to be used to produce renewable fuel with D code of X that is converted to other products and wastes during the production of the batch of co-processed fuel, in Btu.

$E_{endo,DX}$ = The total heat or electricity from renewable biomass qualified to be used to produce renewable fuel with D code of X that is converted to chemical energy in the renewable fuel, other products, and wastes during the production of the batch of co-processed fuel, in Btu. This amount must be proportional to the total amount of heat or electricity that comes from renewable biomass.

(D) *Approach D.* EPA may approve a different approach if the RIN generator demonstrates that the process does not meet the requirements of Approach A, B, or C in paragraphs (f)(4)(i)(A) through (C) of this section, as specified in § 80.1450(b)(1)(xvii)(D).

(ii) For a batch of co-processed intermediate, the biointermediate producer must determine the volume of biointermediate (*i.e.,* V_{bio}) qualified to be used to produce renewable fuel for which RINs may be generated using one of the following approaches:

(A) *Approach A.* (*1*) This approach must only be used for a process that meets all the following requirements:

(*i*) The biointermediate is produced under approved pathways with a single D code.

(*ii*) The fraction of carbon in the co-processed intermediate that originates from renewable biomass does not exceed the fraction of chemical energy in the co-processed intermediate that originates from renewable biomass.

(*2*) V_{bio} must be calculated as follows:

$V_{bio} = V_i * R$

Where:

V_{bio} = Volume of biointermediate, in gallons, qualified to be used to produce renewable fuel for which RINs may be generated.

V_i = Standardized volume of the batch of co-processed intermediate at 60 °F, in gallons, per paragraph (f)(8) of this section.

R = The renewable fraction of the co-processed intermediate as measured by a carbon-14 dating test method, per paragraph (f)(9) of this section.

(B) *Approach B.* (*1*) This approach must only be used for a process that meets all the following requirements:

(*i*) The process does not meet the requirements of Approach A in paragraph (f)(4)(ii)(A) of this section.

(*ii*) Neither heat nor electricity is converted to chemical energy in the co-processed intermediate.

(*iii*) The fraction of chemical energy in the co-processed intermediate that comes from renewable biomass is equal to or greater than the fraction of chemical energy in the feedstocks that comes from renewable biomass.

(*iv*) If the biointermediate produced qualifies to be used to produce renewable fuel eligible to generate both D3/D7 RINs and D4/D5/D6 RINs, the fraction of chemical energy in the co-processed intermediate qualified to be used to produce renewable fuel eligible to generate D3/D7 RINs that comes from renewable biomass is equal to or greater than the fraction of chemical energy in the feedstocks qualified to be used to produce renewable fuel eligible to generate D3/D7 RINs that comes from renewable biomass.

(*v*) If the biointermediate produced qualifies to generate both D4/D5 RINs and D6 RINs, the fraction of chemical energy in the co-processed intermediate qualified to be used to produce renewable fuel eligible to generate D4/D5 RINs that comes from renewable biomass is equal to or greater than the fraction of chemical energy in the feedstocks qualified to be used to produce renewable fuel eligible to generate D4/D5 RINs that comes from renewable biomass.

(*2*) $V_{bio,DX}$ must be calculated as follows:

$V_{bio,DX} = V_i * FE_{R,DX}/(FE_R + FE_{NR})$

Where:

$V_{bio,DX}$ = Volume of biointermediate, in gallons, qualified to be used to produce renewable fuel for which RINs with D code of X may be generated.

V_i = Standardized volume of the batch of co-processed intermediate at 60 °F, in gallons, per paragraph (f)(8) of this section.

$FE_{R,DX}$ = Sum of feedstock energies from renewable biomass used to make the co-processed intermediate that qualify be used to produce renewable fuel with D code of X, in Btu, per paragraph (f)(4)(ii)(B)(*3*) of this section.

FE_R = Sum of feedstock energies from all renewable biomass used to make the co-processed intermediate, in Btu, per paragraph (f)(4)(ii)(B)(*3*) of this section.

FE_{NR} = Sum of feedstock energies from all non-renewable feedstocks used to make the co-processed intermediate, in Btu, per paragraph (f)(4)(ii)(B)(*3*).

(*3*) The feedstock energy value for each feedstock must be calculated as follows:

$FE_i = M_i * (1 - m_i) * E_i$

Where:

FE_i = Feedstock energy of feedstock i, in Btu.

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.

E_i = Energy content of feedstock i, in annual average Btu/lb, per paragraph (f)(7) of this section.

(C) *Approach C.* (*1*) This approach must only be used for a process that meets all the following requirements:

(*i*) The process does not meet the requirements of Approach A or B in paragraphs (f)(4)(ii)(A) and (B) of this section.

(*ii*) Heat or electricity is converted to energy in the co-processed intermediate.

(*2*) $V_{bio,DX}$ must be calculated as follows:

$$V_{bio,DX} = \frac{E_{RB,DX}}{ED}$$

Where:

$V_{bio,DX}$ = Volume of biointermediate, in gallons, qualified to be used to produce renewable fuel for which RINs with D code of X may be generated.

$E_{RB,DX}$ = The chemical energy in the batch of co-processed intermediate that came from chemical energy in renewable biomass qualified to be used to produce renewable fuel with D code of X, in Btu, per paragraph (f)(4)(ii)(C)(*3*) of this section.

ED = The energy density of the biointermediate, in Btu per gallon.

(*3*) $E_{RB,DX}$ must be calculated as follows:

$E_{RB,DX} = E_{feedstock,DX} - E_{exo,DX} - E_{other,DX} + E_{endo,DX}$

Where:

$E_{RB,DX}$ = The chemical energy in the batch of co-processed intermediate that came from chemical energy in renewable biomass qualified to be used to produce renewable fuel with D code of X, in Btu.

$E_{feedstock,DX}$ = The total chemical energy from renewable biomass qualified to be used to produce renewable fuel with D code of X used to produce the batch of co-processed intermediate, in Btu, per paragraph (f)(7) of this section.

$E_{exo,DX}$ = The total chemical energy from renewable biomass qualified to be used to produce renewable fuel with D code of X that is converted to heat during the production of the batch of co-processed intermediate, in Btu.

$E_{other,DX}$ = The total chemical energy from renewable biomass qualified to be used to produce renewable fuel with D code of X that is converted to other products and wastes during the production of the batch of co-processed intermediate, in Btu.

$E_{endo,DX}$ = The total heat or electricity from renewable biomass qualified to be used to produce renewable fuel with D code of X that is converted to chemical energy in the renewable fuel, other products, and wastes during the production of the batch of co-processed intermediate, in

Btu. This amount must be proportional to the total amount of heat or electricity that comes from renewable biomass.

(D) *Approach D.* EPA may approve a different approach if the biointermediate producer demonstrates that the process does not meet the requirements of Approach A, B, or C in paragraphs (f)(4)(ii)(A) through (C) of this section, as specified in § 80.1450(b)(1)(xvii)(D).

* * * * *

(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.

* * * * *

(7) * * *

(i) For purposes of paragraphs (f)(3)(vi), (f)(4)(i)(B), and (f)(4)(ii)(B) of this section, producers must specify the value for E, the energy content of the feedstock components, used in the calculation of the feedstock energy value FE.

* * * * *

(v) * * *

(A) ASTM E870 or ASTM E711 for gross calorific value (both incorporated by reference, see § 80.3).

(B) ASTM D4442 or ASTM D4444 for moisture content (both incorporated by reference, see § 80.3).

* * * * *

(8) * * *

(ii) * * *

(B) The standardized volume of biodiesel at 60 °F, in gallons, as calculated from the use of the American Petroleum Institute Refined Products Table 6B, as referenced in ASTM D1250 (incorporated by reference, see § 80.3).

(9) * * *

(i) Parties required under this part to use a radiocarbon dating test method for determination of the renewable fraction of a co-processed fuel or intermediate must use one of the following methods:

(A) Method B of ASTM D6866 (incorporated by reference, see § 80.3).

(B) If the renewable content of the co-processed fuel or intermediate is 10% or greater, Method C of ASTM D6866.

(C) An alternative test method as approved by EPA that meets all the following requirements:

(*1*) The laboratory meets the requirements related to usage of enriched C–14, as specified in Section 1.4 of ASTM D6866.

(*2*) The result is rounded according to Section 13.4 of ASTM D6866.

(*3*) The uncertainty of the method is less than 0.5%.

(ii) Any party required to test for carbon-14 under this subpart must keep representative samples for at least 30 days after testing is complete.

(A) For liquid samples, at least 330 ml must be retained.

(B) For gaseous samples, at least one gallon at standard temperature and pressure must be retained.

* * * * *

(10) RINs for renewable CNG/LNG produced from biogas that is only distributed via a closed, private, non-commercial system may only be generated if all the following requirements are met:

(i) The renewable CNG/LNG was produced from renewable biomass and qualifies to generate RINs under an approved pathway.

(ii) The RIN generator has entered into a written contract for the sale or use of a specific quantity of renewable CNG/LNG for use as transportation fuel, or has obtained affidavits from all parties selling or using the renewable CNG/LNG as transportation fuel.

(iii) The renewable CNG/LNG was used as transportation fuel and for no other purpose.

(iv) The biogas was introduced into the closed, private, non-commercial system no later than December 31, 2023, and the renewable CNG/LNG was used as transportation fuel no later than December 31, 2024.

(11)(i) 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 to generate RINs 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 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 were continuously measured under § 80.165.

(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, 2023, and the renewable CNG/LNG was used as transportation fuel no later than December 31, 2024.

(ii) On or after January 1, 2024, RINs may only be generated for RNG introduced into a natural gas commercial pipeline system for use as transportation fuel as specified in subpart E of this part.

(iii) If non-renewable components are blended into biogas or RNG, RINs may only be generated on the biomethane content of the biogas or RNG prior to blending.

(12) For purposes of Table 1 of this section, process heat produced from combustion of biogas or RNG at a renewable fuel production facility is considered produced from renewable biomass 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 commercial distribution system and the volume of biogas used as process heat were continuously measured under § 80.165.

(ii) For RNG injected into a commercial distribution system on or before December 31, 2023:

(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 commercial distribution 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 commercial distribution system and the volume of RNG withdrawn were continuously measured under § 80.165.

(E) The commercial distribution 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 January 1, 2024, the renewable fuel producer must retire RINs for RNG as specified in § 80.140.

(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:

(i) The quantity of electricity used at the site that is purchased from the electricity distribution system must be continuously measured and recorded.

(ii) All electricity used on-site that is not purchased from the electricity distribution system must be produced on-site from biogas from landfills or waste digesters.

(iii) For biogas transported to the renewable fuel production facility via a biogas closed distribution system, the requirements in paragraph (f)(12)(i) of this section must be met.

(iv) For RNG injected into a commercial distribution system on or before December 31, 2023, the requirements in paragraph (f)(12)(ii) of this section must be met. For RNG injected into a natural gas commercial pipeline system on or after January 1, 2024, the renewable fuel producer must retire RINs for RNG as specified in § 80.140.

(v) The biogas or RNG used at the renewable fuel production facility is not considered produced from renewable biomass 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 electricity, renewable gasoline, or renewable diesel that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.3) is considered renewable fuel and the producer or importer may generate RINs for such fuel only if all of 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]

■ 17. Amend § 80.1427 by, in paragraph (a)(1) introductory text, removing the text ''under § 80.1406''.

■ 18. Amend § 80.1428 by revising paragraphs (a)(2) through (4) and (a)(5)(i) to read as follows:

§ 80.1428 General requirements for RIN distribution.

(a) * * *

(2) Except as provided in §§ 80.1429 and 80.140(d), no person can separate a RIN that has been assigned to a volume of renewable fuel or RNG pursuant to § 80.1426(e).

(3) An assigned RIN cannot be transferred to another person without simultaneously transferring a volume of renewable fuel or RNG to that same person.

(4) Assigned gallon-RINs with a K code of 1 can be transferred to another person based on the following:

(i) On or before December 31, 2023, for purposes of this section, 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. For RNG, the transferer of assigned RINs with RNG must transfer RINs under § 80.140(c).

(ii) On or after January 1, 2024, for purposes of this section, the transferee must transfer assigned gallon-RINs equal to the equivalence value multiplied by the quantity of the renewable fuel or RNG transferred to the transferor.

(5)(i) On or before December 31, 2023, for purposes of this section, on each of the dates listed in paragraph (a)(5)(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 = Total volume of renewable fuel owned on date d, standardized to 60 °F, in gallons.

* * * * *

■ 19. Amend § 80.1429 by:

■ a. Revising paragraphs (b)(1) through (3);

■ b. Adding paragraph (b)(4)(iii); and

■ c. Revising paragraphs (b)(5) and (6) introductory text.

The revisions and addition read as follows:

§ 80.1429 Requirements for separating RINs from volumes of renewable fuel.

* * * * *

(b) * * *

(1) Except as provided in paragraphs (b)(7) and (9) of this section and § 80.140(d)(2), an obligated party must separate any RINs that have been assigned to a volume of renewable fuel if that party owns that volume.

(2) Except as provided in paragraph (b)(6) of this section, any party that owns a volume of renewable fuel must separate any RINs that have been assigned to that volume once the volume is blended with gasoline or fossil-based diesel to produce a transportation fuel, heating oil, or jet fuel.

(i) On or before December 31, 2023, a party may separate up to 2.5 RINs per gallon of blended renewable fuel.

(ii) On or after January 1, 2024, a party must separate RINs in the amount equal to the equivalence value multiplied by the quantity of the renewable fuel or RNG of the gallon-RINs with a K code of 1.

(3) Any exporter of renewable fuel must separate any RINs that have been assigned to the exported renewable fuel volume.

(i) On or before December 31, 2023, an exporter of renewable fuel may separate up to 2.5 RINs per gallon of exported renewable fuel.

(ii) On or after January 1, 2024, an exporter of renewable fuel must separate RINs in the amount equal to the equivalence value multiplied by the quantity of the renewable fuel or RNG of the gallon-RINs with a K code of 1.

(4) * * *

(iii) Renewable fuel producers of biodiesel may not separate RINs under paragraph (b)(4)(i) of this section.

(5)(i) Any party that generates RINs for a batch of renewable electricity under § 80.135 must separate any RINs that have been assigned to that batch.

(ii) Any party that generates RINs for a batch of renewable CNG/LNG must separate any RINs that have been assigned to that batch if the party demonstrates that the renewable CNG/LNG was used as transportation fuel.

(iii) Only a party that demonstrates that RNG was used as a biogas-derived renewable fuel under § 80.140(d)(1) may separate the RINs that have been assigned to the RNG.

(6) RINs assigned to a volume of biodiesel can only be separated from that volume pursuant to paragraph (b)(2) of this section if such biodiesel is blended into diesel fuel at a concentration of 20 volume percent biodiesel or less.

* * * * *

§ 80.1430 [Amended]

■ 20. Amend § 80.1430 by, in paragraph (e)(2), removing the text ''§ 80.1468'' and adding, in its place, the text ''§ 80.3''.

■ 21. Amend § 80.1431 by:

■ a. Revising paragraphs (a)(1)(vi) and (viii);

■ b. Adding paragraphs (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 meet the definition of renewable fuel.

* * * * *

(viii) Was generated for fuel that was not used in the covered location.

* * * * *

(x) Was inappropriately separated under § 80.140.

* * * * *

(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 of the following conditions and requirements are satisfied and the renewable fuel producer or importer who improperly generated the RINs demonstrates that the conditions and requirements are satisfied through the reporting and recordkeeping requirements set forth below, that:

* * * * *

■ 22. 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 § 80.140(e) must retire the assigned RIN.

* * * * *

§ 80.1435 [Amended]

■ 23. 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''.

■ 24. 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 read 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.

* * * * *

■ 25. 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]

■ 26. 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]

■ 27. Amend § 80.1449 by, in paragraph (e), removing the text ''the Administrator'' and adding, in its place, the text ''EPA''.

■ 28. 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)(D);

■ e. In paragraph (b)(1)(v)(E) removing the text ''the Administrator'' and adding, in its place, the text ''EPA''.

■ 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 ''§ 80.3'';

■ j. Revising paragraphs (b)(1)(xii) introductory text and (b)(1)(xiii)(B) introductory text;

■ k. Adding paragraph (b)(1)(xiii)(C);

■ l. Revising paragraph (b)(1)(xv)(B);

■ m. Adding paragraph (b)(1)(xvii)

■ n. Revising the first sentence of paragraph (b)(2) introductory text and paragraphs (b)(2)(ii) and (iii);

■ o. Redesignating paragraphs (b)(2)(iv) through (vi) as paragraphs (b)(2)(v) through (vii), respectively, and adding a new paragraph (b)(2)(iv);

■ p. Adding paragraphs (b)(2)(viii) and (ix);

■ q. Revising paragraphs (d)(3) introductory text, (d)(3)(ii), and (iii);

■ r. Adding paragraphs (d)(3)(v) and (vi);

■ s. Revising paragraph (g)(10)(ii); and

■ t. 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) * * *

(D) For purposes of this section, for all facilities producing renewable electricity or other renewable fuel from biogas, submit all relevant information in § 80.1426(f)(10) or (11), including all the following:

(*1*) On or before December 31, 2023, for facilities producing renewable CNG/LNG as specified in § 80.1426(f)(10):

(*i*) Copies of all contracts or affidavits, as applicable, that follow the track of the biogas, renewable CNG/LNG, or renewable electricity (*i.e.,* from the biogas producer to the party that processes it into renewable fuel, and finally to the end user that will actually use the renewable electricity or renewable CNG/LNG as transportation fuel.

(*ii*) Specific quantity, heat content, and percent efficiency of transfer, as applicable, and any conversion factors, for the renewable fuel derived from biogas.

(*2*) On or before December 31, 2023, for facilities producing RNG as specified in § 80.1426(f)(11) or renewable electricity under § 80.1426(f)(10) or (11):

(*i*) Copies of all contracts or affidavits, as applicable, that follow the track of the biogas, renewable CNG/LNG, or renewable electricity (*i.e.,* from the biogas producer to the party that processes it into renewable fuel, and finally to the end user that will actually use the renewable electricity or renewable CNG/LNG as transportation fuel).

(*ii*) Specific quantity, heat content, and percent efficiency of transfer, as applicable, and any conversion factors, for the renewable fuel derived from biogas.

* * * * *

(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.

* * * * *

(xii) For a producer or importer of 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 § 80.3), biogas, or renewable electricity, all the following:

* * * * *

(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 provide items (1) through (4) or specify a value and limited conditions in (5):

(*1*) A cellulosic Converted Fraction (CF) for each cellulosic feedstock that will be used for generating RINs under § 80.1426(f)(3)(vi)(D), in Btu/lb, rounded to the nearest whole number.

(*2*) Data supporting the cellulosic CF from each cellulosic feedstock. Data must be derived from processing of cellulosic 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 has 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 including any calculations demonstrating how the data were used to determine the cellulosic CF.

(*4*) A list of ranges of processing conditions, including temperature, solids residence time, and hydraulic residence time, for which the cellulosic CF is accurate and for which the facility must maintain to generate RINs and a description of how such processing conditions will be measured by the facility. RINs generated from facilities operating outside of these conditions will be invalid pursuant § 80.1431(a)(1)(ix).

(*5*) Registering parties choosing at least one of the converted fraction values below in lieu of providing data specified in paragraphs (b)(1)(xiii)(C)(1) through (4) of this section must only use biogas from anaerobic digesters that continuously operate above 95 degrees Fahrenheit with hydraulic and solids residence times greater than 20 days. RINs generated from facilities operating outside of the listed conditions will be invalid pursuant § 80.1431(a)(1)(ix).

(*i*) Swine manure: 1,742 Btu/lb.

(*ii*) Bovine manure: 1,869 Btu/lb.

(*iii*) Chicken manure: 2,700 Btu/lb.

(*iv*) Municipal wastewater treatment sludge: 3,131 Btu/lb.

* * * * *

(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.

* * * * *

(xvii) A RIN generator or biointermediate producer that generates RINs for a co-processed fuel or produces a co-processed intermediate under § 80.1426(f)(4) must provide all the following information for each facility:

(A) Whether Approach A, B, C, or D will be used to generate RINs.

(B) For Approaches A, B, and C, a description of the process and any supporting data describing how the process meets the applicable requirements of the approach.

(C) For Approach C, all the following information:

(*1*) A description of how the renewable fuel or biointermediate producer will determine the values used in all equations for Approach C, including additional information used to determine those values, and an explanation of why this approach is either accurate or provides a conservative estimate of the amount of renewable fuel produced.

(*2*) A list of the meters or other measurement locations that will be used to determine the values for Approach C, including any methods or standards used for each meter or measurement, and a process flow diagram showing their locations.

(*3*) A list of assumptions underlying the calculation of the values for Approach C and an explanation of why each assumption is accurate or provides a conservative estimate of the amount of renewable fuel produced, including a literature review and testing, as applicable.

(*4*) Any additional supporting information needed to evaluate whether Approach C accurately or conservatively estimates the amount of renewable fuel as requested by EPA.

(D) For Approach D, all the following information:

(*1*) A description and any supporting data describing why the process cannot meet the requirements specified for Approaches A, B, and C.

(*2*) A description of how the renewable fuel or biointermediate producer will determine the volume of renewable fuel produced, including relevant equations, and an explanation of why this approach is either accurate or provides a conservative estimate of the volume of renewable fuel produced.

(*3*) A list of the meters or other measurement locations that will be used to determine the values in paragraph (b)(1)(xvii)(D)(*2*) of this section, including any methods or standards used for each meter or measurement, and a process flow diagram showing their locations.

(*4*) A list of assumptions underlying the calculation of the volume of renewable fuel produced and an explanation of why each assumption is accurate or provides a conservative estimate of the amount of renewable fuel produced, including a literature review and testing, as applicable.

(*5*) Any additional supporting information needed to evaluate whether Approach D accurately or conservatively estimates the amount of renewable fuel as requested by EPA.

(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 § 80.145, as applicable.

* * *

* * * * *

(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), (7) through (10), (12), and (13).

(iii) 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.''

(iv)(A) 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.

(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.

(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.

(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.

* * * * *

(viii) 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.

(ix) Reports required under paragraph (b)(2) of this section 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:

* * * * *

(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 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, 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 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. The representative sample must be selected in accordance with the sample size guidelines set forth at 40 CFR 1090.1805 and 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.

* * * * *

(v) Independent third-party engineers must conduct on-site visits required under this paragraph of this section no sooner than July 1 of the calendar year prior to the applicable January 31 deadline.

(vi) The site visit must occur when the renewable fuel production facility is producing renewable fuel or when the biointermediate production facility is producing biointermediates.

* * * * *

(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).

* * * * *

■ 29. 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 ''§ 80.3'';

■ i. Revising paragraph (b)(1)(ii)(U) introductory text;

■ j. Redesignating paragraph (b)(1)(ii)(W) as paragraph (b)(1)(ii)(X) and adding a new paragraph (b)(1)(ii)(W);

■ k. In newly redesignated paragraph (b)(1)(ii)(X), removing the text ''the Administrator'' and adding, in its place, the text ''that EPA'';

■ l. In paragraph (c)(1)(iii)(K), removing the text ''the Administrator'' and adding, in its place, the text ''EPA'';

■ m. In paragraphs (c)(2)(i)(J) and (L), removing the text ''as defined in'' and adding, in its place, the text ''under'';

■ n. In paragraph (c)(2)(i)(R), removing the text ''the Administrator'' and adding, in its place, the text ''EPA'';

■ o. In paragraphs (c)(2)(ii)(D)(*8*) and (*10*), removing the text ''as defined in'' and adding, in its place, the text ''under'';

■ p. Revising paragraph (c)(2)(ii)(D)(*14*);

■ q. In paragraph (c)(2)(ii)(I), removing the text ''the Administrator'' and adding, in its place, the text ''EPA'';

■ r. In paragraph (e) introductory text, remove the text ''as defined in § 80.1401 who'' and adding, in its place, the text ''that'';

■ s. Adding paragraph (f)(4);

■ t. In paragraph (g)(1)(ii)(Q), removing the text ''the Administrator'' and adding, in its place, the text ''that EPA'';

■ u. In paragraphs (g)(2)(xi) and (h)(2), removing the text ''the Administrator'' and adding, in its place, the text ''EPA'';

■ v. In paragraph (j)(1)(xvi), removing the text ''the Administrator'' and adding, in its place, the text ''that EPA''; and

■ w. 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 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 of the following:

* * * * *

(W) Renewable fuel and biointermediate producers that produce co-processed fuel or intermediate under § 80.1426(f)(4) must report the following information, as applicable:

(*1*) For Approach A, the following information by batch:

(*i*) The standardized volume of the batch of co-processed fuel or intermediate at 60 °F, in gallons.

(*ii*) The renewable fraction of the co-processed fuel or intermediate, as a percentage.

(*iii*) The test method used to measure the renewable fraction under § 80.1426(f)(9).

(*2*) For Approach B, the following information by batch:

(*i*) The standardized volume of the batch of co-processed fuel or intermediate at 60 °F, in gallons.

(*ii*) The mass of each feedstock, in pounds.

(*iii*) The average moisture content of each feedstock, as a mass fraction.

(*iv*) The energy content of each feedstock, in Btu/lb.

(*3*) For Approach C, the following information by batch:

(*i*) The energy density of the renewable fuel or biointermediate, in Btu per gallon.

(*ii*) Each input used to calculate $E_{RB,DX,}$ in Btu.

(*4*) For Approach D, all the information specified at registration to be reported, by batch.

* * * * *

(c) * * *

(2) * * *

(ii) * * *

(D) * * *

(*14*) For compliance periods ending on or before December 31, 2023, the volume of renewable fuel (in gallons) owned at the end of the quarter.

* * * * *

(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.

* * * * *

§ 80.1452 [Amended]

■ 30. 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''.

■ 31. Amend § 80.1453 by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraph (a)(11)(i)(D);

■ c. Revising paragraphs (a)(12) introductory text and (a)(12)(v);

■ d. Adding paragraph (a)(12)(viii);

■ e. In paragraphs (d) and (f)(1)(vi), removing the text ''§ 80.1401'' and adding, in its place, the text ''§ 80.2''; and

■ f. 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 of the following information, as applicable:

* * * * *

(11) * * *

(i) * * *

(D) Beginning January 1, 2024, the identifying information for a RIN must also include the assigned equivalence value of the renewable fuel along with the following statement: ''These assigned RINs may only be separated up to the amount of the assigned equivalence value on a per-gallon basis''.

* * * * *

(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 § 80.160.

* * * * *

■ 32. 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 paragraphs (c)(1) introductory text, (c)(1)(iii), and (c)(2) introductory text, removing the text ''(as defined in § 80.1401)'';

■ f. Adding paragraphs (c)(2)(vii) and (c)(3);

■ g. Revising paragraph (d) introductory text;

■ h. Redesignating paragraphs (d)(1) through (4) as paragraphs (d)(2) through (5), respectively, and adding a new paragraph (d)(1);

■ i. In newly redesignated paragraph (d)(2)(ii), removing the text ''(d)(1)(i)'' and adding, in its place, the text ''(d)(2)(i)'';

■ j. 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)'';

■ k. Revising newly redesignated paragraph (d)(5);

■ l. Adding paragraph (d)(6);
■ m. In paragraphs (h)(3)(iv) and (v), removing the text ''as defined in § 80.1401'';
■ n. Removing paragraphs (h)(6)(vi) and (vii);
■ o. Revising paragraph (j) introductory text;
■ p. In paragraphs (j)(1)(iii) and (j)(2)(iv), removing the text ''the Administrator'' and adding, in its place, the text ''EPA'';
■ q. Revising paragraph (k) introductory text;
■ r. In paragraph (k)(2)(v), removing the text ''the Administrator'' and adding, in its place, the text ''EPA'';
■ s. Revising paragraph (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 supplier 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 supplier 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) *Additional requirements for producers of renewable CNG/LNG, biogas and electricity in pathways involving grain sorghum as feedstock, and renewable fuel that uses process heat from biogas.* (1) *Renewable CNG/LNG.* A renewable fuel producer that generates RINs for renewable CNG/LNG under § 80.1426(f)(10) or (11), or that uses process heat from biogas to produce renewable fuel under § 80.1426(f)(12), must keep all the following additional records:

(i) Documentation recording the sale of renewable CNG/LNG for use as transportation fuel relied upon in § 80.1426(f)(10), § 80.1426(f)(11), or for use of biogas for process heat to make renewable fuel as relied upon in § 80.1426(f)(12) and the transfer of title of the biogas, or renewable CNG/LNG from the point of biogas production to the facility which sells or uses the fuel for transportation purposes.

(ii) Documents demonstrating the volume, energy content, and applicable D code of biogas or renewable CNG/LNG relied upon under § 80.1426(f)(10) that was delivered to the facility which sells or uses the fuel for transportation purposes.

(iii) Documents demonstrating the volume, energy content, and applicable D code of biogas or renewable CNG/LNG relied upon under § 80.1426(f)(11) or (12), as applicable, that was placed into the commercial distribution system.

(iv) Documents demonstrating the volume and energy content of biogas relied upon under § 80.1426(f)(12) at the point of distribution.

(v) Affidavits, EPA-approved documentation, or data from a real-time electronic monitoring system, confirming that the amount of the biogas or renewable CNG/LNG relied upon under § 80.1426(f)(10) and (11) was used as transportation fuel and for no other purpose. The RIN generator must obtain affidavits, or monitoring system data under this paragraph (k), for each quarter.

(vi) A copy of the biogas producer's Compliance Certification required under Title V of the Clean Air Act.

(vii) Any other records as requested by EPA.

(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 of 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 § 80.3), biogas-derived renewable fuel or renewable electricity shall keep all of the following additional records:

* * * * *

§ 80.1455 [Removed and Reserved]

■ 33. Remove and reserve § 80.1455.

§ 80.1457 [Amended]

■ 34. Amend § 80.1457 by, in paragraph (b)(8), removing the text ''the Administrator'' and adding, in its place, the text ''that EPA''.

■ 35. Add § 80.1458 to read as follows:

§ 80.1458 Storage of renewable fuel and 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 of the requirements in this section are met.

(2) 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 of the requirements in this section are met.

(b) *Storage requirements.* In order for a renewable fuel producer or biointermediate producer to store renewable fuel or biointermediate under this section, the producer must do the following:

(1) Produce the stored renewable fuel or stored biointermediate after an independent third-party engineer has conducted an engineering review for the renewable fuel production or biointermediate production facility under § 80.1450(b)(2).

(2) Produce the stored renewable fuel or stored 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 stored renewable fuel or stored biointermediate at the facility that produced the renewable fuel or biointermediate.

(5) Maintain custody and title to the stored renewable fuel or stored biointermediate until EPA accepts the renewable fuel or biointermediate producer's registration under § 80.1450(b).

(c) *RIN generation.* (1) A RIN generator may only generate RINs for stored renewable fuel or renewable fuel produced from stored biointermediate if the RIN generator generates the RINs under §§ 80.1426 and 80.1452 after EPA activates the 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 or renewable fuel produced from stored biointermediate is the year that the renewable fuel was produced.

(d) *Limitations.* (1) RNG injected into a commercial distribution system prior to EPA acceptance of a renewable fuel producer's registration under § 80.1450(b) does not meet the requirements of this section and may not be stored.

(2) Renewable electricity produced and placed on a transmission grid prior to EPA activation of a renewable electricity generator's registration under § 80.145 does not meet the requirements of this section and may not be stored.

■ 36. Amend § 80.1460 by:

■ a. In paragraphs (c)(2) and (3), removing the text ''(as defined in § 80.1401)'';

■ b. In paragraph (g), removing the text ''§ 80.1401'' and adding, in its place, the text ''§ 80.2'';

■ c. Revising paragraph (h)(3); and

■ d. Adding paragraph (l).

The revision and addition read as follows:

§ 80.1460 What acts are prohibited under the RFS program?

* * * * *

(h) * * *

(3)(i) On or before December 31, 2023, separate more than 2.5 RINs per gallon of renewable fuel that has a valid qualifying separation event pursuant to § 80.1429.

(ii) On or after January 1, 2024, separate more RINs per gallon than the equivalence value assigned to the renewable fuel that has a valid qualifying separation event pursuant to § 80.1429.

* * * * *

(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).

■ 37. 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.

■ 38. Amend § 80.1464 by:

■ a. In the introductory paragraph, removing the text ''§§ 80.1465 and 80.1466'' and adding, in its place, the text ''§ 80.1466'';

■ b. In paragraph (a) introductory text, removing the text ''(as described at § 80.1406(a))'' and ''(as described at § 80.1430)'';

■ c. Revising paragraph (a)(3)(ii);

■ d. 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'';

■ e. In paragraph (b)(1)(v)(B), removing the text ''in § 80.1401''; and

■ f. Revising paragraphs (b)(3)(ii) and (c)(3)(ii).

The revisions read as follows:

§ 80.1464 What are the attest engagement requirements under the RFS program?

(a) * * *

(3) * * *

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (a)(2) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of each

quarter; and state whether this information agrees with the party's reports to EPA.

* * * * *

(b) * * *

(3) * * *

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (b)(2) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; report the total number of each RIN generated during each quarter and compute and report the total number of current-year and prior-year RINs owned at the start and end of each quarter; and state whether this information agrees with the party's reports to EPA.

* * * * *

(c) * * *

(2) * * *

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (c)(1) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of each quarter; and state whether this information agrees with the party's reports to EPA.

* * * * *

■ 39. 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 * $0.30

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.

* * * * *

■ 40. 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 * $ 0.30

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]

■ 41. Remove and reserve § 80.1468.

■ 42. 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 (b)(1)(i), removing the text ''as defined in § 80.1401'';

■ d. 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'';

■ e. In paragraph (c)(1)(i), removing the text ''as defined in § 80.1401'';

■ f. Revising paragraphs (c)(4) introductory text;

■ g. In paragraph (c)(4)(i), removing the text ''§ 80.1429(b)(4)'' and adding, in its place, the text ''§ 80.1429(b)'';

■ h. Adding paragraph (c)(6);

■ i. Revising paragraph (d); and

■ j. In paragraph (e)(1), removing the text ''the Administrator'' and adding, in its place, the text ''EPA''.

The addition and revision 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 a RIN-generating approved pathway, which must contain elements specific to particular feedstocks, production processes, and fuel types, as applicable.

* * * * *

■ 43. Amend § 80.1471 by:

■ a. Revising paragraph (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 (13).

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 for the audited party in the same calendar year 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 conducted past research, development, design, or construction, or consulting regarding such activities for the audited party within the last year. For purposes of this requirement, consulting does not include performing or participating in verification activities pursuant to this section.

(11) The independent third-party auditor and its contractors and subcontractors must not provide other business or consulting services to the audited party, including advice or assistance to implement the findings or recommendations in an audit report, for a period of at least one year following cessation of QAP services for the audited party.

(12) 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 do not accept future employment with the owner or operator of the audited party for a period of at least 12 months. For purposes of this requirement, employment does not include performing or participating in the third-party audit (including the verification activities) pursuant to § 80.1472.

(13) 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]

■ 44. 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]

■ 45. Amend § 80.1474 by, in paragraph (g), removing the text ''the Administrator'' and adding, in its place, the text ''EPA''.

§ 80.1478 [Amended]

■ 46. Amend § 80.1478 by, in paragraph (g)(1), removing the text ''the Administrator'' wherever it appears and adding, in its place, the text ''EPA''.

■ 47. 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 third-party feedstock supplier to supply these feedstocks may comply with the alternative recordkeeping requirements of this section.

(b) *Registration of the feedstock supplier.* The feedstock supplier must register under 40 CFR 1090.805.

(c) *QAP participation.* (1) The feedstock supplier and renewable fuel producer must have an approved QAP as specified in § 80.1476(e).

(2) Instead of verifying RINs with a site visit 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 supplier'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 supplier must keep all applicable records for the collection of separated yard waste, separated food waste, separated MSW, and biogenic waste oils/fats/greases as specified in § 80.1454.

(f) *Liability.* The feedstock supplier and renewable fuel producer are liable for violations as specified in § 80.1461(e).

PART 1090—REGULATION OF FUELS, FUEL ADDITIVES, AND REGULATED BLENDSTOCKS

■ 48. 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

■ 49. 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.

■ 50. Amend § 1090.80 by:

■ a. In the definition of ''PADD'', revising entry II in the table; and

■ b. In the definition of ''Ultra low-sulfur diesel'', removing the text ''Ultra low-sulfur diesel'' and adding, in its place, the text ''Ultra-low-sulfur diesel''.

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

■ 51. 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]

■ 52. Amend § 1090.1830 by, in paragraph (a)(3), adding the text ''all'' after the text ''submitted''.

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