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Vol. 87, No. 250

Friday, December 30, 2022

BUREAU OF CONSUMER FINANCIAL PROTECTION

12 CFR Part 1003

Home Mortgage Disclosure (Regulation C) Adjustment to Asset-Size Exemption Threshold

AGENCY: Bureau of Consumer Financial Protection.

ACTION: Final rule; official interpretation.

SUMMARY: The Consumer Financial Protection Bureau (Bureau) is amending the official commentary that interprets the requirements of the Bureau's Regulation C (Home Mortgage Disclosure) to reflect the asset-size exemption threshold for banks, savings associations, and credit unions based on the annual percentage change in the average of the Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI–W). Based on the 8.6 percent increase in the average of the CPI–W for the 12-month period ending in November 2022, the exemption threshold is adjusted to $54 million from $50 million. Therefore, banks, savings associations, and credit unions with assets of $54 million or less as of December 31, 2022, are exempt from collecting data in 2023.

DATES: This rule is effective on January 1, 2023.

FOR FURTHER INFORMATION CONTACT: Adrien Fernandez, Counsel, Thomas Dowell, Senior Counsel; Office of Regulations, at (202) 435–7700. If you require this document in an alternative electronic format, please contact *CFPB_Accessibility@cfpb.gov.*

SUPPLEMENTARY INFORMATION: The Bureau is amending Regulation C, which implements the HMDA asset thresholds, to establish the asset-sized exemption threshold for depository financial institution for 2023. The asset threshold will be $54 million for 2023.

I. Background

The Home Mortgage Disclosure Act of 1975 (HMDA)[1] requires most mortgage lenders located in metropolitan areas to collect data about their housing related lending activity. Annually, lenders must report their data to the appropriate Federal agencies and make the data available to the public. The Bureau's Regulation C implements HMDA.[2]

Prior to 1997, HMDA exempted certain depository institutions as defined in HMDA (*i.e.,* banks, savings associations, and credit unions) with assets totaling $10 million or less as of the preceding year-end. In 1996, HMDA was amended to expand the asset-size exemption for these depository institutions.[3] The amendment increased the dollar amount of the asset-size exemption threshold by requiring a one-time adjustment of the $10 million figure based on the percentage by which the CPI–W for 1996 exceeded the CPI–W for 1975, and it provided for annual adjustments thereafter based on the annual percentage increase in the CPI–W, rounded to the nearest multiple of $1 million.

The definition of ''financial institution'' in § 1003.2(g) provides that the Bureau will adjust the asset threshold based on the year-to-year change in the average of the CPI–W, not seasonally adjusted, for each 12-month period ending in November, rounded to the nearest $1 million. For 2022, the threshold was $50 million. During the 12-month period ending in November 2022, the average of the CPI–W increased by 8.6 percent. As a result, the exemption threshold is increased to $54 million for 2023. Thus, banks, savings associations, and credit unions with assets of $54 million or less as of December 31, 2022, are exempt from collecting data in 2023. An institution's exemption from collecting data in 2023 does not affect its responsibility to report data it was required to collect in 2022.

II. Procedural Requirements

A. Administrative Procedure Act

Under the Administrative Procedure Act (APA), notice and opportunity for public comment are not required if the Bureau finds that notice and public comment are impracticable, unnecessary, or contrary to the public interest.[4] Pursuant to this final rule, comment 2(g)–2 in Regulation C, supplement I, is amended to update the exemption threshold. The amendment in this final rule is technical and non-discretionary, and it merely applies the formula established by Regulation C for determining any adjustments to the exemption threshold. For these reasons, the Bureau has determined that publishing a notice of proposed rulemaking and providing opportunity for public comment are unnecessary. Therefore, the amendment is adopted in final form.

Section 553(d) of the APA generally requires publication of a final rule not less than 30 days before its effective date, except (1) a substantive rule which grants or recognizes an exemption or relieves a restriction; (2) interpretive rules and statements of policy; or (3) as otherwise provided by the agency for good cause found and published with the rule.[5] At a minimum, the Bureau believes the amendments fall under the third exception to section 553(d). The Bureau finds that there is good cause to make the amendments effective on January 1, 2023. The amendment in this final rule is technical and non-discretionary, and it applies the method previously established in the agency's regulations for determining adjustments to the threshold.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) does not apply to a rulemaking where a general notice of proposed rulemaking is not required.[6] As noted previously, the Bureau has determined that it is unnecessary to publish a general notice of proposed rulemaking for this final rule. Accordingly, the RFA's requirement relating to an initial and final regulatory flexibility analysis do not apply.

C. Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995,[7] the Bureau reviewed this final rule. The Bureau has determined that this rule does not create any new information collections or

[1] 12 U.S.C. 2801–2810.

[2] 12 CFR part 1003.

[3] 12 U.S.C. 2808(b).

[4] 5 U.S.C. 553(b)(B).

[5] 5 U.S.C. 553(d).

[6] 5 U.S.C. 603(a), 604(a).

[7] 44 U.S.C. 3506; 5 CFR part 1320.

substantially revise any existing collections.

D. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), the Bureau will submit a report containing this rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to the rule taking effect. The Office of Information and Regulatory Affairs (OIRA) has designated this rule as not a ''major rule'' as defined by 5 U.S.C. 804(2).

III. Signing Authority

Senior Advisor Brian Shearer, having reviewed and approved this document, is delegating the authority to sign this document electronically to Laura Galban, a Bureau Federal Register Liaison, for purposes of publication in the **Federal Register**.

List of Subjects in 12 CFR Part 1003

Banks, banking, Credit unions, Mortgages, National banks, Reporting and recordkeeping requirements, Savings associations.

Authority and Issuance

For the reasons set forth above, the Bureau amends Regulation C, 12 CFR part 1003, as set forth below:

PART 1003—HOME MORTGAGE DISCLOSURE (REGULATION C)

■ 1. The authority citation for part 1003 continues to read as follows:

Authority: 12 U.S.C. 2803, 2804, 2805, 5512, 5581.

■ 2. Supplement I to part 1003 is amended by revising *2(g) Financial Institution* under the heading *Section 1003.2—Definitions* to read as follows:

Supplement I to Part 1003—Official Interpretations

* * * * *

Section 1003.2—Definitions

* * * * *

2(g) Financial Institution

1. *Preceding calendar year and preceding December 31.* The definition of financial institution refers both to the preceding calendar year and the preceding December 31. These terms refer to the calendar year and the December 31 preceding the current calendar year. For example, in 2019, the preceding calendar year is 2018 and the preceding December 31 is December 31, 2018. Accordingly, in 2019, Financial Institution A satisfies the asset-size threshold described in § 1003.2(g)(1)(i) if its assets exceeded the threshold specified in comment 2(g)–2 on December 31, 2018. Likewise, in 2020, Financial Institution A does not meet the loan-volume test described in § 1003.2(g)(1)(v)(A) if it originated fewer than 25 closed-end mortgage loans during either 2018 or 2019.

2. *Adjustment of exemption threshold for banks, savings associations, and credit unions.* For data collection in 2023, the asset-size exemption threshold is $54 million. Banks, savings associations, and credit unions with assets at or below $54 million as of December 31, 2022, are exempt from collecting data for 2023.

3. Merger or acquisition—coverage of surviving or newly formed institution. After a merger or acquisition, the surviving or newly formed institution is a financial institution under § 1003.2(g) if it, considering the combined assets, location, and lending activity of the surviving or newly formed institution and the merged or acquired institutions or acquired branches, satisfies the criteria included in § 1003.2(g). For example, A and B merge. The surviving or newly formed institution meets the loan threshold described in § 1003.2(g)(1)(v)(B) if the surviving or newly formed institution, A, and B originated a combined total of at least 200 open-end lines of credit in each of the two preceding calendar years. Likewise, the surviving or newly formed institution meets the asset-size threshold in § 1003.2(g)(1)(i) if its assets and the combined assets of A and B on December 31 of the preceding calendar year exceeded the threshold described in § 1003.2(g)(1)(i). Comment 2(g)–4 discusses a financial institution's responsibilities during the calendar year of a merger.

4. Merger or acquisition—coverage for calendar year of merger or acquisition. The scenarios described below illustrate a financial institution's responsibilities for the calendar year of a merger or acquisition. For purposes of these illustrations, a ''covered institution'' means a financial institution, as defined in § 1003.2(g), that is not exempt from reporting under § 1003.3(a), and ''an institution that is not covered'' means either an institution that is not a financial institution, as defined in § 1003.2(g), or an institution that is exempt from reporting under § 1003.3(a).

i. Two institutions that are not covered merge. The surviving or newly formed institution meets all of the requirements necessary to be a covered institution. No data collection is required for the calendar year of the merger (even though the merger creates an institution that meets all of the requirements necessary to be a covered institution). When a branch office of an institution that is not covered is acquired by another institution that is not covered, and the acquisition results in a covered institution, no data collection is required for the calendar year of the acquisition.

ii. A covered institution and an institution that is not covered merge. The covered institution is the surviving institution, or a new covered institution is formed. For the calendar year of the merger, data collection is required for covered loans and applications handled in the offices of the merged institution that was previously covered and is optional for covered loans and applications handled in offices of the merged institution that was previously not covered. When a covered institution acquires a branch office of an institution that is not covered, data collection is optional for covered loans and applications handled by the acquired branch office for the calendar year of the acquisition.

iii. A covered institution and an institution that is not covered merge. The institution that is not covered is the surviving institution, or a new institution that is not covered is formed. For the calendar year of the merger, data collection is required for covered loans and applications handled in offices of the previously covered institution that took place prior to the merger. After the merger date, data collection is optional for covered loans and applications handled in the offices of the institution that was previously covered. When an institution remains not covered after acquiring a branch office of a covered institution, data collection is required for transactions of the acquired branch office that take place prior to the acquisition. Data collection by the acquired branch office is optional for transactions taking place in the remainder of the calendar year after the acquisition.

iv. Two covered institutions merge. The surviving or newly formed institution is a covered institution. Data collection is required for the entire calendar year of the merger. The surviving or newly formed institution files either a consolidated submission or separate submissions for that calendar year. When a covered institution acquires a branch office of a covered institution, data collection is required for the entire calendar year of the merger. Data for the acquired branch office may be submitted by either institution.

5. Originations. Whether an institution is a financial institution depends in part on whether the institution originated at least 25 closed-end mortgage loans in each of the two preceding calendar years or at least 200 open-end lines of credit in each of the two preceding calendar years. Comments 4(a)-2 through –4 discuss whether activities with respect to a particular closed-end mortgage loan or open-end line of credit constitute an origination for purposes of § 1003.2(g).

6. Branches of foreign banks—treated as banks. A Federal branch or a State-licensed or insured branch of a foreign bank that meets the definition of a ''bank'' under section 3(a)(1) of the Federal Deposit Insurance Act (12 U.S.C. 1813(a)) is a bank for the purposes of § 1003.2(g).

7. Branches and offices of foreign banks and other entities—treated as nondepository financial institutions. A Federal agency, State-licensed agency, State-licensed uninsured branch of a foreign bank, commercial lending company owned or controlled by a foreign bank, or entity operating under section 25 or 25A of the Federal Reserve Act, 12 U.S.C. 601 and 611 (Edge Act and agreement corporations) may not meet the definition of ''bank'' under the Federal Deposit Insurance Act and may thereby fail to satisfy the definition of a depository financial institution under § 1003.2(g)(1). An entity is nonetheless a financial institution if it meets the definition of nondepository financial institution under § 1003.2(g)(2).

* * * * *

Laura Galban,

Federal Register Liaison, Consumer Financial Protection Bureau.

[FR Doc. 2022–28441 Filed 12–29–22; 8:45 am]

BILLING CODE 4810–AM–P

BUREAU OF CONSUMER FINANCIAL PROTECTION

12 CFR Part 1026

Truth in Lending Act (Regulation Z) Adjustment to Asset-Size Exemption Threshold

AGENCY: Bureau of Consumer Financial Protection.

ACTION: Final rule; official interpretation.

SUMMARY: The Consumer Financial Protection Bureau (Bureau) is amending the official commentary to its Regulation Z in order to make annual adjustments to the asset-size thresholds exempting certain creditors from the requirement to establish an escrow account for a higher-priced mortgage loan (HPML). These changes reflect updates to the exemption from the escrow requirement in the Truth in Lending Act (TILA) for creditors that, together with their affiliates that regularly extended covered transactions secured by first liens, had total assets of less than $2 billion (adjusted annually for inflation). They also reflect updates to the exemption the Bureau added, by implementing section 108 of the Economic Growth, Regulatory Relief, and Consumer Protection Act (EGRRCPA), for certain insured depository institutions and insured credit unions with assets of $10 billion or less (adjusted annually for inflation). These amendments are based on the annual percentage change in the average of the Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI–W). Based on the 8.6 percent increase in the average of the CPI–W for the 12-month period ending in November 2022, the exemption threshold for creditors and their affiliates that regularly extended covered transactions secured by first liens is adjusted to $2.537 billion from $2.336 billion and the exemption threshold for certain insured depository institutions and insured credit unions with assets of $10 billion or less is adjusted to $11.374 billion from $10.473 billion.

DATES: This rule is effective on January 1, 2023.

FOR FURTHER INFORMATION CONTACT: Adrien Fernandez, Counsel, Thomas Dowell, Senior Counsel, Office of Regulations, at (202) 435–7700. If you require this document in an alternative electronic format, please contact *CFPB_Accessibility@cfpb.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Section 129D of TILA generally requires creditors to establish escrow accounts for certain first-lien higher-priced mortgage loan transactions. However, TILA section 129D also permits the Bureau to exempt creditors from this higher-priced mortgage loan escrow requirement if they meet certain requirements, including any asset-size threshold that the Bureau may establish.

In the 2013 Escrows Final Rule,[1] the Bureau established an asset-size threshold of $2 billion, which would adjust automatically each year, based on the year-to-year change in the average of the CPI–W for each 12-month period ending in November, with rounding to the nearest million dollars.[2] In 2015, the Bureau revised the asset-size threshold for small creditors and how it applies. The Bureau included in the calculation of the asset-size threshold the assets of the creditor's affiliates that regularly extended covered transactions secured by first liens during the applicable period and added a grace period to allow an otherwise eligible creditor that exceeded the asset limit in the preceding calendar year (but not in the calendar year before the preceding year) to continue to operate as a small creditor with respect to transactions with applications received before April 1 of the current calendar year.[3] For 2022, the threshold was $2.336 billion.

During the 12-month period ending in November 2022, the average of the CPI–W increased by 8.6 percent. As a result, the exemption threshold is increased to $2.537 billion for 2023. Thus, if the creditor's assets together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2022 are less than $2.537 billion on December 31, 2022, and it meets the other requirements of § 1026.35(b)(2)(iii), the creditor will be exempt from the escrow-accounts requirement for higher-priced mortgage loans in 2023 and will also be exempt from the escrow-accounts requirement for higher-priced mortgage loans for purposes of any loan consummated in 2024 with applications received before April 1, 2024. The adjustment to the escrows asset-size exemption threshold also will increase the threshold for small-creditor portfolio and balloon-payment qualified mortgages under Regulation Z. The requirements for small-creditor portfolio qualified mortgages at § 1026.43(e)(5)(i)(D) reference the asset threshold in § 1026.35(b)(2)(iii)(C). Likewise, the requirements for balloon-payment qualified mortgages at § 1026.43(f)(1)(vi) reference the asset threshold in § 1026.35(b)(2)(iii)(C). Under § 1026.32(d)(1)(ii)(C), balloon-payment qualified mortgages that satisfy all applicable criteria in § 1026.43(f)(1)(i) through (vi) and (f)(2), including being made by creditors that have (together with certain affiliates) total assets below

[1] 78 FR 4726 (Jan. 22, 2013).

[2] *See* 12 CFR 1026.35(b)(2)(iii)(C).

[3] *See* 80 FR 59943, 59951 (Oct. 2, 2015). The Bureau also issued an interim final rule in March 2016 to revise certain provisions in Regulation Z to effectuate the Helping Expand Lending Practices in Rural Communities Act's amendments to TILA (Pub. L. 114–94, section 89003, 129 Stat. 1312, 1800–01 (2015)). The rule broadened the cohort of creditors that may be eligible under TILA for the special provisions allowing origination of balloon-payment qualified mortgages and balloon-payment high-cost mortgages, as well as for the escrow exemption. *See* 81 FR 16074 (Mar. 25, 2016).

the threshold in § 1026.35(b)(2)(iii)(C), are also excepted from the prohibition on balloon payments for high-cost mortgages.

In the 2018 Economic Growth, Regulatory Relief, and Consumer Protection Act (EGRRCPA),[4] Congress directed the Bureau to issue regulations to add a new exemption from TILA's escrow requirement that exempts transactions by certain insured depository institutions and insured credit unions.[5] In 2021, the Bureau issued a final rule implementing this exemption in § 1026.35(b)(2)(vi) (2021 Escrows Rule).[6] The final rule exempted from the Regulation Z HPML escrow requirement any loan made by an insured depository institution or insured credit union and secured by a first lien on the principal dwelling of a consumer if: (1) the institution has assets of $10 billion or less; (2) the institution and its affiliates originated 1,000 or fewer loans secured by a first lien on a principal dwelling during the preceding calendar year; and (3) certain of the existing HPML escrow exemption criteria are met. In the 2021 Escrows Rule, the Bureau established an asset-size threshold of $10 billion or less in § 1026.35(b)(2)(vi)(A), which will adjust automatically each year, based on the year-to-year change in the average of the CPI–W, not seasonally adjusted, for each 12-month period ending in November, with rounding to the nearest million dollars. Unlike the asset threshold in § 1026.35(b)(2)(iii) and the other thresholds in § 1026.35(b)(2)(vi), affiliates are not considered in calculating compliance with this asset threshold. For calendar year 2022, the asset threshold was $10.473 billion.

During the 12-month period ending in November 2022, the average of the CPI–W increased by 8.6 percent. As a result, the exemption threshold is increased to $11.374 billion for 2023. Thus, a creditor that is an insured depository institution or insured credit union that during calendar year 2022 had assets of $11.374 billion or less on December 31, 2022, satisfies this criterion for purposes of any loan consummated in 2023 and for purposes of any loan secured by a first lien on a principal dwelling of a consumer consummated in 2024 for which the application was received before April 1, 2024.

[4] Public Law 115–174, 132 Stat. 1296 (2018).

[5] EGRRCPA section 108, 132 Stat. 1304–05; 15 U.S.C. 1639d(c)(2).

[6] 86 FR 9840 (Feb. 17, 2021).

II. Procedural Requirements

A. Administrative Procedure Act

Under the Administrative Procedure Act (APA), notice and opportunity for public comment are not required if the Bureau finds that notice and public comment are impracticable, unnecessary, or contrary to the public interest. 5 U.S.C. 553(b)(B). Pursuant to this final rule, comment 35(b)(2)(iii)–1 in Regulation Z is amended to update the exemption threshold in § 1026.35(b)(2)(iii) and comment 35(b)(2)(vi)(A)–1 in Regulation Z is amended to update the exemption threshold in § 1026.35(b)(2)(vi). The amendments in this final rule are technical and merely apply the formulae previously established in Regulation Z for determining any adjustments to the exemption thresholds. For these reasons, the Bureau has determined that publishing a notice of proposed rulemaking and providing opportunity for public comment are unnecessary. Therefore, the amendments are adopted in final form.

Section 553(d) of the APA generally requires publication of a final rule not less than 30 days before its effective date, except (1) a substantive rule which grants or recognizes an exemption or relieves a restriction; (2) interpretive rules and statements of policy; or (3) as otherwise provided by the agency for good cause found and published with the rule. 5 U.S.C. 553(d). At a minimum, the Bureau believes the amendments fall under the third exception to section 553(d). The Bureau finds that there is good cause to make the amendments effective on January 1, 2023. The amendment in this final rule is technical and non-discretionary, and it merely applies the method previously established in the agency's regulations for automatic adjustments to the threshold.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) does not apply to a rulemaking where a general notice of proposed rulemaking is not required.[7] As noted previously, the Bureau has determined that it is unnecessary to publish a general notice of proposed rulemaking for this final rule. Accordingly, the RFA's requirement relating to an initial and final regulatory flexibility analysis do not apply.

C. Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995,[8] the Bureau reviewed this final rule. The Bureau has determined that this rule does not create any new information collections or substantially revise any existing collections.

[7] 5 U.S.C. 603(a), 604(a).

[8] 44 U.S.C. 3506; 5 CFR part 1320.

D. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), the Bureau will submit a report containing this rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to the rule taking effect. The Office of Information and Regulatory Affairs (OIRA) has designated this rule as not a ''major rule'' as defined by 5 U.S.C. 804(2).

E. Signing Authority

Senior Advisor Brian Shearer, having reviewed and approved this document, is delegating the authority to electronically sign this document to Laura Galban, a Bureau Federal Register Liaison, for purposes of publication in the **Federal Register**.

List of Subjects in 12 CFR Part 1026

Advertising, Banks, banking, Consumer protection, Credit, Credit unions, Mortgages, National banks, Reporting and recordkeeping requirements, Savings associations, Truth-in-lending.

Authority and Issuance

For the reasons set forth above, the Bureau amends Regulation Z, 12 CFR part 1026, as set forth below:

PART 1026—TRUTH IN LENDING (REGULATION Z)

■ 1. The authority citation for part 1026 continues to read as follows:

Authority: 12 U.S.C. 2601, 2603–2605, 2607, 2609, 2617, 3353, 5511, 5512, 5532, 5581; 15 U.S.C. 1601 *et seq.*

■ 2. In supplement I to part 1026, under *§ 1026.35—Requirements for Higher-Priced Mortgage Loans, 35(b)(2) Exemptions, Paragraphs 35(b)(2)(iii) and (vi)(A)* are revised to read as follows:

Supplement I to Part 1026—Official Interpretations

* * * * *

Subpart E—Special Rules for Certain Home Mortgage Transactions

* * * * *

Section 1026.35—Requirements for Higher-Priced Mortgage Loans

* * * * *

35(b)(2) Exemptions.

* * * * *

Paragraph 35(b)(2)(iii).

1. *Requirements for exemption.* Under § 1026.35(b)(2)(iii), except as provided in § 1026.35(b)(2)(v), a creditor need not establish an escrow account for taxes and insurance for a higher-priced mortgage loan, provided the following four conditions are satisfied when the higher-priced mortgage loan is consummated:

i. During the preceding calendar year, or during either of the two preceding calendar years if the application for the loan was received before April 1 of the current calendar year, a creditor extended a first-lien covered transaction, as defined in § 1026.43(b)(1), secured by a property located in an area that is either ''rural'' or ''underserved,'' as set forth in § 1026.35(b)(2)(iv).

A. In general, whether the rural-or-underserved test is satisfied depends on the creditor's activity during the preceding calendar year. However, if the application for the loan in question was received before April 1 of the current calendar year, the creditor may instead meet the rural-or-underserved test based on its activity during the next-to-last calendar year. This provides creditors with a grace period if their activity meets the rural-or-underserved test (in § 1026.35(b)(2)(iii)(A)) in one calendar year but fails to meet it in the next calendar year.

B. A creditor meets the rural-or-underserved test for any higher-priced mortgage loan consummated during a calendar year if it extended a first-lien covered transaction in the preceding calendar year secured by a property located in a rural-or-underserved area. If the creditor does not meet the rural-or-underserved test in the preceding calendar year, the creditor meets this condition for a higher-priced mortgage loan consummated during the current calendar year only if the application for the loan was received before April 1 of the current calendar year and the creditor extended a first-lien covered transaction during the next-to-last calendar year that is secured by a property located in a rural or underserved area. The following examples are illustrative:

1. Assume that a creditor extended during 2016 a first-lien covered transaction that is secured by a property located in a rural or underserved area. Because the creditor extended a first-lien covered transaction during 2016 that is secured by a property located in a rural or underserved area, the creditor can meet this condition for exemption for any higher-priced mortgage loan consummated during 2017.

2. Assume that a creditor did not extend during 2016 a first-lien covered transaction secured by a property that is located in a rural or underserved area. Assume further that the same creditor extended during 2015 a first-lien covered transaction that is located in a rural or underserved area. Assume further that the creditor consummates a higher-priced mortgage loan in 2017 for which the application was received in November 2017. Because the creditor did not extend during 2016 a first-lien covered transaction secured by a property that is located in a rural or underserved area, and the application was received on or after April 1, 2017, the creditor does not meet this condition for exemption. However, assume instead that the creditor consummates a higher-priced mortgage loan in 2017 based on an application received in February 2017. The creditor meets this condition for exemption for this loan because the application was received before April 1, 2017, and the creditor extended during 2015 a first-lien covered transaction that is located in a rural or underserved area.

ii. The creditor and its affiliates together extended no more than 2,000 covered transactions, as defined in § 1026.43(b)(1), secured by first liens, that were sold, assigned, or otherwise transferred by the creditor or its affiliates to another person, or that were subject at the time of consummation to a commitment to be acquired by another person, during the preceding calendar year or during either of the two preceding calendar years if the application for the loan was received before April 1 of the current calendar year. For purposes of § 1026.35(b)(2)(iii)(B), a transfer of a first-lien covered transaction to ''another person'' includes a transfer by a creditor to its affiliate.

A. In general, whether this condition is satisfied depends on the creditor's activity during the preceding calendar year. However, if the application for the loan in question is received before April 1 of the current calendar year, the creditor may instead meet this condition based on activity during the next-to-last calendar year. This provides creditors with a grace period if their activity falls at or below the threshold in one calendar year but exceeds it in the next calendar year.

B. For example, assume that in 2015 a creditor and its affiliates together extended 1,500 loans that were sold, assigned, or otherwise transferred by the creditor or its affiliates to another person, or that were subject at the time of consummation to a commitment to be acquired by another person, and 2,500 such loans in 2016. Because the 2016 transaction activity exceeds the threshold but the 2015 transaction activity does not, the creditor satisfies this condition for exemption for a higher-priced mortgage loan consummated during 2017 if the creditor received the application for the loan before April 1, 2017, but does not satisfy this condition for a higher-priced mortgage loan consummated during 2017 if the application for the loan was received on or after April 1, 2017.

C. For purposes of § 1026.35(b)(2)(iii)(B), extensions of first-lien covered transactions, during the applicable time period, by all of a creditor's affiliates, as ''affiliate'' is defined in § 1026.32(b)(5), are counted toward the threshold in this section. ''Affiliate'' is defined in § 1026.32(b)(5) as ''any company that controls, is controlled by, or is under common control with another company, as set forth in the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*).'' Under the Bank Holding Company Act, a company has control over a bank or another company if it directly or indirectly or acting through one or more persons owns, controls, or has power to vote 25 per centum or more of any class of voting securities of the bank or company; it controls in any manner the election of a majority of the directors or trustees of the bank or company; or the Federal Reserve Board determines, after notice and opportunity for hearing, that the company directly or indirectly exercises a controlling influence over the management or policies of the bank or company. 12 U.S.C. 1841(a)(2).

iii. As of the end of the preceding calendar year, or as of the end of either of the two preceding calendar years if the application for the loan was received before April 1 of the current calendar year, the creditor and its affiliates that regularly extended covered transactions secured by first liens, together, had total assets that are less than the applicable annual asset threshold.

A. For purposes of § 1026.35(b)(2)(iii)(C), in addition to the creditor's assets, only the assets of a creditor's ''affiliate'' (as defined by § 1026.32(b)(5)) that regularly extended covered transactions (as defined by § 1026.43(b)(1)) secured by first liens, are counted toward the applicable annual asset threshold. *See* comment 35(b)(2)(iii)–1.ii.C for discussion of definition of ''affiliate.''

B. Only the assets of a creditor's affiliate that regularly extended first-lien covered transactions during the applicable period are included in calculating the creditor's assets. The meaning of ''regularly extended'' is based on the number of times a person extends consumer credit for purposes of the definition of ''creditor'' in § 1026.2(a)(17). Because covered transactions are ''transactions secured by a dwelling,'' consistent with § 1026.2(a)(17)(v), an affiliate regularly extended covered transactions if it extended more than five covered transactions in a calendar year. Also consistent with § 1026.2(a)(17)(v), because a covered transaction may be a high-cost mortgage subject to § 1026.32, an affiliate regularly extends covered transactions if, in any 12-month period, it extends more than one covered transaction that is subject to the requirements of § 1026.32 or one or more such transactions through a mortgage broker. Thus, if a creditor's affiliate regularly extended first-lien covered transactions during the preceding calendar year, the creditor's assets as of the end of the preceding calendar year, for purposes of the asset limit, take into account the assets of that affiliate. If the creditor, together with its affiliates that regularly extended first-lien covered transactions, exceeded the asset limit in the preceding calendar year—to be eligible to operate as a small creditor for transactions with applications received before April 1 of the current calendar year—the assets of the creditor's affiliates that regularly extended covered transactions in the year before the preceding calendar year are included in calculating the creditor's assets.

C. If multiple creditors share ownership of a company that regularly extended first-lien covered transactions, the assets of the company count toward the asset limit for a co-owner creditor if the company is an ''affiliate,'' as defined in § 1026.32(b)(5), of the co-owner creditor. Assuming the company is not an affiliate of the co-owner creditor by virtue of any other aspect of the definition (such as by the company and co-owner creditor being under common control), the company's assets are included toward the asset limit of the co-owner creditor only if the company is controlled by the co-owner creditor, ''as set forth in the Bank Holding Company Act.'' If the co-owner creditor and the company are affiliates (by virtue of any aspect of the definition), the co-owner creditor counts all of the company's assets toward the asset limit, regardless of the co-owner creditor's ownership share. Further, because the co-owner and the company are mutual affiliates the company also would count all of the co-owner's assets towards its own asset limit. *See* comment 35(b)(2)(iii)–1.ii.C for discussion of the definition of ''affiliate.''

D. A creditor satisfies the criterion in § 1026.35(b)(2)(iii)(C) for purposes of any higher-priced mortgage loan consummated during 2016, for example, if the creditor (together with its affiliates that regularly extended first-lien covered transactions) had total assets of less than the applicable asset threshold on December 31, 2015. A creditor that (together with its affiliates that regularly extended first-lien covered transactions) did not meet the applicable asset threshold on December 31, 2015, satisfies this criterion for a higher-priced mortgage loan consummated during 2016 if the application for the loan was received before April 1, 2016, and the creditor (together with its affiliates that regularly extended first-lien covered transactions) had total assets of less than the applicable asset threshold on December 31, 2014.

E. Under § 1026.35(b)(2)(iii)(C), the $2,000,000,000 asset threshold adjusts automatically each year based on the year-to-year change in the average of the Consumer Price Index for Urban Wage Earners and Clerical Workers, not seasonally adjusted, for each 12-month period ending in November, with rounding to the nearest million dollars. The Bureau will publish notice of the asset threshold each year by amending this comment. For calendar year 2023, the asset threshold is $2,537,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2022 has total assets of less than $2,537,000,000 on December 31, 2022, satisfies this criterion for purposes of any loan consummated in 2023 and for purposes of any loan consummated in 2024 for which the application was received before April 1, 2024. For historical purposes:

1. For calendar year 2013, the asset threshold was $2,000,000,000. Creditors that had total assets of less than $2,000,000,000 on December 31, 2012, satisfied this criterion for purposes of the exemption during 2013.

2. For calendar year 2014, the asset threshold was $2,028,000,000. Creditors that had total assets of less than $2,028,000,000 on December 31, 2013, satisfied this criterion for purposes of the exemption during 2014.

3. For calendar year 2015, the asset threshold was $2,060,000,000. Creditors that had total assets of less than $2,060,000,000 on December 31, 2014, satisfied this criterion for purposes of any loan consummated in 2015 and, if the creditor's assets together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2014 were less than that amount, for purposes of any loan consummated in 2016 for which the application was received before April 1, 2016.

4. For calendar year 2016, the asset threshold was $2,052,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2015 had total assets of less than $2,052,000,000 on December 31, 2015, satisfied this criterion for purposes of any loan consummated in 2016 and for purposes of any loan consummated in 2017 for which the application was received before April 1, 2017.

5. For calendar year 2017, the asset threshold was $2,069,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2016 had total assets of less than $2,069,000,000 on December 31, 2016, satisfied this criterion for purposes of any loan consummated in 2017 and for purposes of any loan consummated in 2018 for which the application was received before April 1, 2018.

6. For calendar year 2018, the asset threshold was $2,112,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2017 had total assets of less than $2,112,000,000 on December 31, 2017, satisfied this criterion for purposes of any loan consummated in 2018 and for purposes of any loan consummated in 2019 for which the application was received before April 1, 2019.

7. For calendar year 2019, the asset threshold was $2,167,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2018 had total assets of less than $2,167,000,000 on December 31, 2018, satisfied this criterion for purposes of any loan consummated in 2019 and for purposes of any loan consummated in 2020 for which the application was received before April 1, 2020.

8. For calendar year 2020, the asset threshold was $2,202,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2019 had total assets of less than $2,202,000,000 on December 31, 2019, satisfied this criterion for purposes of any loan consummated in 2020 and for purposes of any loan consummated in 2021 for which the application was received before April 1, 2021.

9. For calendar year 2021, the asset threshold was $2,230,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2020 had total assets of less than $2,230,000,000 on December 31, 2020, satisfied this criterion for purposes of any loan consummated in 2021 and for purposes of any loan consummated in 2022 for which the application was received before April 1, 2022.

10. For calendar year 2022, the asset threshold was $2,336,000,000. A creditor that together with the assets of its affiliates that regularly extended first-lien covered transactions during calendar year 2021 had total assets of less than $2,336,000,000 on December 31, 2021, satisfied this criterion for purposes of any loan consummated in 2022 and for purposes of any loan consummated in 2023 for which the application was received before April 1, 2023.

iv. The creditor and its affiliates do not maintain an escrow account for any mortgage transaction being serviced by the creditor or its affiliate at the time the transaction is consummated, except as provided in § 1026.35(b)(2)(iii)(D)(*1*) and (*2*). Thus, the exemption applies, provided the other conditions of § 1026.35(b)(2)(iii) (or, if applicable, the conditions for the exemption in § 1026.35(b)(2)(vi)) are satisfied, even if the creditor previously maintained escrow accounts for mortgage loans, provided it no longer maintains any such accounts except as provided in § 1026.35(b)(2)(iii)(D)(*1*) and (*2*). Once a creditor or its affiliate begins escrowing for loans currently serviced other than those addressed in § 1026.35(b)(2)(iii)(D)(*1*) and (*2*), however, the creditor and its affiliate become ineligible for the exemption in § 1026.35(b)(2)(iii) and (vi) on higher-priced mortgage loans they make while such escrowing continues. Thus, as long as a creditor (or its affiliate) services and maintains escrow accounts for any mortgage loans, other than as provided in § 1026.35(b)(2)(iii)(D)(*1*) and (*2*), the creditor will not be eligible for the exemption for any higher-priced mortgage loan it may make. For purposes of § 1026.35(b)(2)(iii) and (vi), a creditor or its affiliate ''maintains'' an escrow account only if it services a mortgage loan for which an escrow account has been established at least through the due date of the second periodic payment under the terms of the legal obligation.

* * * * *

Paragraph 35(b)(2)(vi)(A).

1. The asset threshold in § 1026.35(b)(2)(vi)(A) will adjust automatically each year, based on the year-to-year change in the average of the Consumer Price Index for Urban Wage Earners and Clerical Workers, not seasonally adjusted, for each 12-month period ending in November, with rounding to the nearest million dollars. Unlike the asset threshold in § 1026.35(b)(2)(iii) and the other thresholds in § 1026.35(b)(2)(vi), affiliates are not considered in calculating compliance with this threshold. The Bureau will publish notice of the asset threshold each year by amending this comment. For calendar year 2023, the asset threshold is $11,374,000,000. A creditor that is an insured depository institution or insured credit union that during calendar year 2022 had assets of $11,374,000,000 or less on December 31, 2022, satisfies this criterion for purposes of any loan consummated in 2023 and for purposes of any loan secured by a first lien on a principal dwelling of a consumer consummated in 2024 for which the application was received before April 1, 2024. For historical purposes:

1. For calendar year 2021, the asset threshold was $10,000,000,000. Creditors that had total assets of 10,000,000,000 or less on December 31, 2020, satisfied this criterion for purposes of any loan consummated in 2021 and for purposes of any loan secured by a first lien on a principal dwelling of a consumer consummated in 2022 for which the application was received before April 1, 2022.

2. For calendar year 2022, the asset threshold was $10,473,000,000. Creditors that had total assets of $10,473,000,000 or less on December 31, 2021, satisfied this criterion for purposes of any loan consummated in 2022 and for purposes of any loan secured by a first lien on a principal dwelling of a consumer consummated in 2023 for which the application was received before April 1, 2023.

Laura Galban,

Federal Register Liaison, Consumer Financial Protection Bureau.

[FR Doc. 2022–28439 Filed 12–29–22; 8:45 am]

BILLING CODE 4810–AM–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1238; Project Identifier MCAI–2022–00741–T; Amendment 39–22290; AD 2022–27–05]

RIN 2120–AA64

Airworthiness Directives; Dassault Aviation Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is superseding Airworthiness Directive (AD) 2022–09–15, which applied to all Dassault Aviation Model FALCON 2000 and FALCON 2000EX airplanes. AD 2022–09–15 required relocating affected servo-valves and revising the existing airplane flight manual (AFM) to provide temporary information necessary to operate airplanes fitted with at least one affected brake servo-valve. AD 2022–09–15 also limited or prohibited the installation of affected brake servo-valves. This AD was prompted by a determination that replacing certain brake servo-valves is necessary to address the unsafe condition. This AD continues to require the actions in AD 2022–09–15, including the parts installation limitation or prohibition, and also requires replacing an affected part with a serviceable part, as specified in a European Union Aviation Safety Agency (EASA) AD, which is incorporated by reference (IBR). The FAA is issuing this AD to address the unsafe condition on these products.

DATES: This AD is effective February 3, 2023.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of May 31, 2022 (87 FR 29217, May 13, 2022).

ADDRESSES:

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA–2022–1238; or in person at Docket Operations between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this final rule, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The address for Docket Operations is U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.

Material Incorporated by Reference:

• For EASA material incorporated by reference in this AD, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu.* You may find this material on the EASA website at *ad.easa.europa.eu.*

• You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195. It is also available at *regulations.gov* under Docket No. FAA–2022–1238.

FOR FURTHER INFORMATION CONTACT: Tom Rodriguez, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone: 206–231–3226; email: *Tom.Rodriguez@faa.gov*.

SUPPLEMENTARY INFORMATION:

Background

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 to supersede AD 2022–09–15, Amendment 39–22035 (87 FR 29217, May 13, 2022), (AD 2022–09–15). AD 2022–09–15 applied to all Dassault Aviation Model FALCON 2000 and FALCON 2000EX airplanes. AD 2022–09–15 required relocating affected servo-valves and revising the existing AFM to provide temporary information necessary to operate airplanes fitted with at least one affected brake servo-valve. AD 2022–09–15 also limited or prohibited the installation of affected brake servo-valves. The FAA issued AD 2022–09–15 to prevent temporary failure of the brake servo-valves, which could lead to reduced braking performance during landing including degraded or dissymmetric braking, possibly resulting in reduced control of the airplane, lateral excursion of the runway, and consequent damage to the airplane.

The NPRM published in the **Federal Register** on October 20, 2022 (87 FR 63706). The NPRM was prompted by Emergency AD 2022–0068–E, dated April 14, 2022, issued by EASA, which is the Technical Agent for the Member States of the European Union (EASA Emergency AD 2022–0068–E) (referred to after this as the MCAI). The MCAI states that occurrences were reported of brake system failure during landing. Subsequent investigation determined the root cause to be a brake control-valve failure which was a result of application of inappropriate oiling during production and maintenance, affecting a specific batch of affected parts. This condition, if not addressed, could lead to reduced braking performance during landing, possibly resulting in reduced control of, and consequent damage to, the airplane. The NPRM was also prompted by a determination that replacing certain brake servo-valves is necessary to address the unsafe condition. AD 2022–09–15 did not require that replacement, because the planned compliance time for that replacement would have allowed enough time to provide notice and opportunity for prior public comment on the merits of the action. The FAA determined that the replacement is needed, and is therefore issuing this AD to require the replacement.

In the NPRM, the FAA proposed to retain all of the requirements of AD 2022–09–15, including the parts installation limitation or prohibition. The NPRM also proposed to require replacing affected brake servo-valves, as specified in EASA Emergency AD 2022–0068–E.

You may examine the MCAI in the AD docket at *regulations.gov* under Docket No. FAA–2022–1238.

Discussion of Final Airworthiness Directive

Comments

The FAA received no comments on the NPRM or on the determination of the cost to the public.

Conclusion

This product has been approved by the aviation authority of another country and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with this State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI referenced above. The FAA reviewed the relevant data and determined that air safety requires adopting this AD as proposed. Accordingly, the FAA is issuing this AD to address the unsafe condition on this product. Except for minor editorial changes, this AD is adopted as proposed in the NPRM. None of the changes will increase the economic burden on any operator.

Related Service Information Under 1 CFR Part 51

This AD requires EASA Emergency AD 2022–0068–E, which the Director of the Federal Register approved for incorporation by reference as of May 31, 2022 (87 FR 29217, May 13, 2022). This material is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in **ADDRESSES**.

Costs of Compliance

The FAA estimates that this AD affects 441 airplanes of U.S. registry. The FAA estimates the following costs to comply with this AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Relocation	10 work-hours × $85 per hour = $850	$0	$850	$374,850
AFM revision	1 work-hour × $85 per hour = $85	0	85	37,485
Replacement	10 work-hours × $85 per hour = $850	11,690	12,540	5,530,140

The FAA has included all known costs in its cost estimate. According to the manufacturer, however, some or all of the costs of this AD may be covered under warranty, thereby reducing the cost impact on affected operators.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

The FAA is issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: General requirements. Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

The FAA has determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect 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.

For the reasons discussed above, I certify that this AD:

(1) Is not a ''significant regulatory action'' under Executive Order 12866,

(2) Will not affect intrastate aviation in Alaska, and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by:

■ a. Removing Airworthiness Directive 2022–09–15, Amendment 39–22035 (87 FR 29217, May 13, 2022); and

■ b. Adding the following new airworthiness directive:

2022–27–05 Dassault Aviation: Amendment 39–22290; Docket No. FAA–2022–1238; Project Identifier MCAI–2022–00741–T.

(a) Effective Date

This airworthiness directive (AD) is effective February 3, 2023.

(b) Affected ADs

This AD replaces AD 2022–09–15, Amendment 39–22035 (87 FR 29217, May 13, 2022) (AD 2022–09–15).

(c) Applicability

This AD applies to all Dassault Aviation Model FALCON 2000 and FALCON 2000EX airplanes, certificated in any category.

(d) Subject

Air Transport Association (ATA) of America Code 32, Landing gear.

(e) Unsafe Condition

This AD was prompted by a determination that replacing certain brake servo-valves is necessary and reports of brake system failures during landing. The FAA is issuing this AD to prevent temporary failure of the brake servo-valves, which could lead to reduced braking performance during landing including degraded or dissymmetric braking, possibly resulting in reduced control of the airplane, lateral excursion of the runway, and consequent damage to the airplane.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Requirements

Except as specified in paragraphs (h) and (i) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, European Union Aviation Safety Agency (EASA) Emergency AD 2022–0068–E, dated April 14, 2022 (EASA Emergency AD 2022–0068–E).

(h) Exceptions to EASA Emergency AD 2022–0068–E

(1) Where paragraphs (1) and (2) of EASA Emergency AD 2022–0068–E refer to its effective date, this AD requires using May 31, 2022 (the effective date of AD 2022–09–15).

(2) Where paragraph (4) of EASA Emergency AD 2022–0068–E refers to its effective date, this AD requires using the effective date of this AD.

(3) Where paragraph (2) of EASA Emergency AD 2022–0068–E specifies to ''inform all flight crews, and, thereafter, operate the aeroplane accordingly,'' this AD does not require those actions as those actions are already required by existing FAA operating regulations (see 14 CFR 91.9, 91.505, and 121.137).

(4) This AD does not adopt the ''Remarks'' section of EASA Emergency AD 2022–0068–E.

(i) No Reporting or Return of Parts

Although the service information referenced in EASA Emergency AD 2022–0068–E specifies to submit certain information and send removed parts to the manufacturer, this AD does not include that requirement.

(j) Additional FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, International Validation Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the International Validation Branch, send it to the attention of the person identified in paragraph (k) of this AD. Information may be emailed to: *9-AVS-AIR-730-AMOC@faa.gov.* Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain instructions from a manufacturer, the instructions must be accomplished using a method approved by the Manager, International Validation Branch, FAA; or EASA; or Dassault Aviation's EASA Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(k) Additional Information

For more information about this AD, contact Tom Rodriguez, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3226; email *Tom.Rodriguez@faa.gov.*

(l) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference (IBR) of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless the AD specifies otherwise.

(3) The following service information was approved for IBR on May 31, 2022 (87 FR 29217, May 13, 2022).

(i) European Union Aviation Safety Agency (EASA) Emergency AD 2022–0068–E, dated April 14, 2022.

(ii) [Reserved]

(4) For EASA Emergency AD 2022–0068–E, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu.* You may find this EASA AD on the EASA website at *ad.easa.europa.eu.*

(5) You may view this material at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

(6) You may view this material that is incorporated by reference at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email *fr.inspection@nara.gov,* or go to: *www.archives.gov/federal-register/cfr/ibr-locations.html.*

Issued on December 21, 2022.

Christina Underwood,

Acting Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2022–28383 Filed 12–29–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

DEPARTMENT OF THE TREASURY

19 CFR Parts 24

[CBP Dec. 22–26; Docket No. USCBP–2018–0033]

RIN 1515–AE39

Refund of Alcohol Excise Tax

AGENCY: U.S. Customs and Border Protection, Department of Homeland Security; Department of the Treasury.

ACTION: Interim final rule; request for comments.

SUMMARY: This document amends U.S. Customs and Border Protection regulations to implement certain changes made by the Taxpayer Certainty and Disaster Tax Relief Act of 2020, which amended the Craft Beverage Modernization Act provisions of the Tax Cuts and Jobs Act of 2017. Pursuant to these changes, the responsibility for administering refunds, reduced tax rates, and tax credits on imported alcohol is moving from U.S. Customs and Border Protection (CBP) to the U.S. Department of the Treasury, effective January 1, 2023.

DATES: This interim final rule is effective January 1, 2023; comments must be received by March 2, 2023.

ADDRESSES: You may submit comments, identified by docket number Docket No. USCBP–2018–0033, by one of the following methods:

- *Federal Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Due to COVID–19-related restrictions, CBP has temporarily suspended its ability to receive public comments by mail.

Instructions: All submissions received must include the agency name and docket number for this rulemaking. All comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided. For detailed instructions on submitting comments and additional information on the rulemaking process, see the 'Public Participation' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov.* Due to the relevant COVID–19-related restrictions, CBP has temporarily suspended on-site public inspection of the public comments.

FOR FURTHER INFORMATION CONTACT: Kellee Gross, Branch Chief, Trade Processes Branch, Office of Trade, 202–815–1699, *kellee.m.gross@cbp.dhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Public Participation

Interested persons are invited to participate in this rulemaking by submitting written data, views or arguments on all aspects of the interim rule. See **ADDRESSES** above for information on how to submit comments. U.S. Customs and Border Protection (CBP) also invites comments that relate to the effects that might result from this interim rule. Comments that will provide the most assistance to CBP will reference a specific portion of the interim rule, explain the reason for any recommended change, and include data, information, or authority that supports such recommended change.

II. Background

Sections 13801–13808 of the Tax Cuts and Jobs Act of 2017 (Pub. L. 115–97), signed December 22, 2017, commonly referred to as the Craft Beverage Modernization Act (CBMA), amended the Internal Revenue Code for two calendar years with respect to the tax treatment of alcoholic beverages, including beer, wine, and distilled spirits. The CBMA authorized reduced tax rates and tax credits for alcoholic beverages. On August 16, 2018, CBP published an interim final rule, CBP Dec. 18–09, in the **Federal Register** (83 FR 40675), updating the language of title 19 of the Code of Federal Regulations (CFR) to implement the CBMA and make other technical changes to 19 CFR part 24. Specifically, the interim final rule amended 19 CFR 24.36 to encompass CBP's authority to refund the difference between the full excise tax rate paid by an importer to CBP at the time of entry summary filing and the CBMA's lower effective tax rate. CBP solicited comments on this interim final rule. No comments were received. On December 19, 2019, the Further Consolidated Appropriations Act was signed, which extended the relevant provisions of the CBMA through calendar year 2020. *See* Public Law 116–94.

On December 27, 2020, the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (Tax Relief Act) was enacted. *See* Public Law 116–260, Division EE, sections 106–110. The Tax Relief Act amended and made permanent the CBMA. Section 107(e) of the Tax Relief Act directed that the Secretary of the Treasury (or the Secretary's delegate within the Department of the Treasury (Treasury)) shall implement and administer the new statutory provisions in coordination with CBP. In June 2021, Treasury informed Congress that it intended to delegate administration of the CBMA import refund program, formerly administered by CBP under 19 CFR 24.36(d)(10), to the Alcohol and Tobacco Tax and Trade Bureau (TTB) in the ''Report to Congress on Administration of Craft Beverage Modernization Act Refund Claims for Imported Alcohol.'' [1] The authority subsequently was delegated to TTB.

On September 23, 2022, TTB published a temporary rule in the **Federal Register** (87 FR 58021) to implement regulations for the administration of the CBMA. Concurrent with the temporary rule, TTB published a Notice of Proposed Rulemaking in the **Federal Register** (87 FR 58043) proposing to make the temporary regulations final and soliciting comments.

Likewise, CBP is publishing this interim final rule to update the regulations issued in CBP Dec. 18–09 to reflect the transfer of authority for administration of the CBMA import refund program to TTB beginning on January 1, 2023, and to direct the public to the relevant TTB regulations regarding refunds administered by TTB. CBP is accepting comments on these changes to the regulations.

III. Discussion of Changes to § 24.36

Section 24.36 deals with refunds of excessive duties, taxes, fees, or interest. CBP is amending the introductory text to paragraph (d) to clarify the basis for TTB's authority to administer refunds arising under the CBMA beginning on January 1, 2023. CBP is amending paragraph (d)(10) to state that it applies to goods entered or withdrawn from warehouse on or before December 31, 2022, because after that date TTB will handle the refunds covered by the paragraph. CBP is also amending paragraph (d)(10) to reflect that the statutory authorities, giving CBP the authority to administer claims pertaining to these goods entered or withdrawn from warehouse on or before December 31, 2022, reauthorized the CBMA twice.[2] CBP is also amending

[1] ''Report to Congress on Administration of Craft Beverage Modernization Act Refund Claims for Imported Alcohol,'' June 2021, available at *https://www.ttb.gov/images/pdfs/treasury-cbma-import-claims-report-june-2021.pdf.*

[2] The Further Consolidated Appropriations Act, Public Law 116–94 (December 20, 2019), reauthorized the CBMA for 2020. The Taxpayer Certainty and Disaster Tax Relief Act of 2020,

paragraph (e) by removing the entirety of the existing paragraph and replacing it with revised paragraphs (e)(1) and (e)(2) to clearly direct the public to the relevant TTB regulations. Paragraph (e)(1) directs the public to the TTB regulations governing refunds for overpayment of alcohol and tobacco excise taxes. Paragraph (e)(2) directs the public to the TTB regulations governing refunds for alcohol excise taxes on or after January 1, 2023, based on assignment of a reduced tax rate or tax credits to an importer by a foreign producer. The refunds described in paragraph (e) are administered by TTB.

IV. Statutory and Regulatory Requirements

A. Inapplicability of Notice and Delayed Effective Date

The Administrative Procedure Act (APA) requirements in 5 U.S.C. 553 govern agency rulemaking procedures. Section 553(b) of the APA generally requires notice and public comment before issuance of a final rule. In addition, section 553(d) of the APA requires that a final rule have a 30-day delayed effective date. The APA, however, provides exceptions from the prior notice and the public comment and the delayed effective date requirements, when an agency for good cause finds that such procedures are ''impracticable, unnecessary, or contrary to the public interest.'' *See* 5 U.S.C. 553(b)(3)(B), (d)(3). Treasury and CBP find that prior notice and comment are unnecessary, and that good cause exists to issue these regulations effective on January 1, 2023. Prior notice and comment are unnecessary, as required in 5 U.S.C. 553(b)(3)(B), because the rule does not substantively alter the underlying rights or interests of importers or filers, but instead corrects the regulations to clarify that the authority to administer CBMA refund claims is being transferred from CBP to TTB on January 1, 2023, by statute. For the same reason, CBP finds that good cause exists for dispensing with the requirement for a delayed effective date as required in 5 U.S.C. 553(d)(3).

B. Executive Orders 13563 and 12866

Executive Orders 13563 and 12866 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Executive Order 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility. This interim final rule is not a ''significant regulatory action,'' under section 3(f) of Executive Order 12866. Accordingly, the Office of Management and Budget (OMB) has not reviewed this regulation.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), as amended by the Small Business Regulatory Enforcement and Fairness Act of 1996, requires an agency to prepare and make available to the public a regulatory flexibility analysis that describes the effect of a proposed rule on small entities (*i.e.,* small businesses, small organizations, and small governmental jurisdictions) when the agency is required to publish a general notice of proposed rulemaking for a rule. Since a general notice of proposed rulemaking is not necessary for this rule, CBP is not required to prepare a regulatory flexibility analysis for this rule.

D. Paperwork Reduction Act

The provisions of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, and its implementing regulations, 5 CFR part 1320, do not apply to this final rule, because this final rule does not trigger any new or revised recordkeeping or reporting.

E. Signing Authority

This regulation is being issued in accordance with 19 CFR 0.1(a)(1) pertaining to the Secretary of the Treasury's authority (or that of his/her delegate) to approve regulations related to customs revenue functions.

Troy A. Miller, the Acting Commissioner of CBP, having reviewed and approved this document, has delegated the authority to electronically sign this document to Robert F. Altneu, who is the Director of the Regulations and Disclosure Law Division for CBP, for purposes of publication in the **Federal Register**.

List of Subjects

19 CFR Part 24

Accounting, Claims, Harbors, Reporting and recordkeeping requirements, Taxes.

Amendments to the Regulations

For the reasons stated above, part 24 of Title 19 of the Code of Federal Regulations is amended as set forth below:

PART 24—CUSTOMS FINANCIAL AND ACCOUNTING PROCEDURE

■ 1. The general and specific authority citations for Part 24 are revised to read as follows:

Authority: 5 U.S.C. 301; 19 U.S.C. 58a–58c, 66, 1202 (General Note 3(i), Harmonized Tariff Schedule of the United States), 1505, 1520, 1624; 26 U.S.C. 4461, 4462; 31 U.S.C. 3717, 9701; Pub. L. 107–296, 116 Stat. 2135 (6 U.S.C. 1 *et seq.*).

* * * * *

Section 24.36 also issued under 26 U.S.C. 5001(c)(4), 5041(c)(7), 5051(a)(6), 6423; Pub. L. 115–97; Pub. L. 116–260; 134 Stat. 3046.

* * * * *

■ 2. Amend § 24.36 by revising paragraph (d) introductory text, and paragraphs (d)(10) and (e) to read as follows:

§ 24.36 Refunds of excessive duties, taxes, etc.

* * * * *

(d) The authority of CBP to make refunds pursuant to paragraphs (a), (b), and (c) of this section of excessive deposits of alcohol or tobacco taxes, as defined in section 6423(d)(1), Internal Revenue Code of 1986, as amended (26 U.S.C. 6423(d)(1)), is confined to cases of the types which are excepted from the application of section 6423, Internal Revenue Code of 1986, as amended (26 U.S.C. 6423), and which are not administered by the Department of the Treasury under section 107(e) of Public Law 116–260, div. EE, title I (December 27, 2020). The excepted types of cases and, therefore, the types in which CBP is authorized to make refunds of such taxes are those in which:

* * * * *

(10) For alcohol excise taxes imposed under the Internal Revenue Code for goods entered or withdrawn from warehouse for consumption on or before December 31, 2022, the refund of tax is claimed pursuant to the assignment of a reduced tax rate or tax credit to an importer by a foreign producer in accordance with CBP implementation of sections 13801–13808 of Public Law 115–97 (December 22, 2017), as amended. For goods entered or withdrawn from warehouse for consumption after December 31, 2022, see the procedures provided in paragraph (e)(2) of this section.

(e) In any instance in which a refund of an alcohol or tobacco tax is not of a type covered by paragraph (d) of this section the following procedures will apply:

(1) Except as provided in paragraph (e)(2), a claim for refund of any overpayment of internal revenue tax on an entry must be filed with the Alcohol

Public Law 116–260 (December 27, 2020), made the CBMA permanent and gave CBP the authority to administer CBMA claims through December 31, 2022.

and Tobacco Tax and Trade Bureau (TTB), in accordance with TTB regulations found in Part 70 of Title 27 of the Code of Federal Regulations.

(2) A claim for refund of alcohol excise taxes based on the assignment of a reduced tax rate or tax credit to an importer by a foreign good producer for goods entered or withdrawn from warehouse for consumption on or after January 1, 2023, and submitted pursuant to 26 U.S.C. 5001(c)(4), 5041(c)(7), and 5051(a)(6), must be filed with TTB, in accordance with TTB regulations found in Part 27, subpart P, of Title 27 of the Code of Federal Regulations.

Robert F. Altneu,

Director, Regulations & Disclosure Law Division, Regulations & Rulings, Office of Trade, U.S. Customs and Border Protection.

Approved:

Thomas C. West Jr.,

Deputy Assistant Secretary of the Treasury for Tax Policy.

[FR Doc. 2022–28375 Filed 12–29–22; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 882

[Docket No. FDA–2022–N–3188]

Medical Devices; Neurological Devices; Classification of the Pediatric Autism Spectrum Disorder Diagnosis Aid

AGENCY: Food and Drug Administration, HHS.

ACTION: Final amendment; final order.

SUMMARY: The Food and Drug Administration (FDA, Agency, or we) is classifying the pediatric Autism Spectrum Disorder (ASD) diagnosis aid into class II (special controls). The special controls that apply to the device type are identified in this order and will be part of the codified language for the pediatric Autism Spectrum Disorder diagnosis aid's classification. We are taking this action because we have determined that classifying the device into class II (special controls) will provide a reasonable assurance of safety and effectiveness of the device. We believe this action will also enhance patients' access to beneficial innovative devices.

DATES: This order is effective December 30, 2022. The classification was applicable on June 2, 2021.

FOR FURTHER INFORMATION CONTACT: Mohua Choudhury, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 4102, Silver Spring, MD 20993–0002, 240–402–3095, *Mohua.Choudhury@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Upon request, FDA has classified the pediatric Autism Spectrum Disorder diagnosis aid as class II (special controls), which we have determined will provide a reasonable assurance of safety and effectiveness. In addition, we believe this action will enhance patients' access to beneficial innovation, in part by placing the device into a lower device class than the automatic class III assignment.

The automatic assignment of class III occurs by operation of law and without any action by FDA, regardless of the level of risk posed by the new device. Any device that was not in commercial distribution before May 28, 1976, is automatically classified as, and remains within, class III and requires premarket approval unless and until FDA takes an action to classify or reclassify the device (see 21 U.S.C. 360c(f)(1)). We refer to these devices as ''postamendments devices'' because they were not in commercial distribution prior to the date of enactment of the Medical Device Amendments of 1976, which amended the Federal Food, Drug, and Cosmetic Act (FD&C Act).

FDA may take a variety of actions in appropriate circumstances to classify or reclassify a device into class I or II. We may issue an order finding a new device to be substantially equivalent under section 513(i) of the FD&C Act (see 21 U.S.C. 360c(i)) to a predicate device that does not require premarket approval. We determine whether a new device is substantially equivalent to a predicate device by means of the procedures for premarket notification under section 510(k) of the FD&C Act (21 U.S.C. 360(k)) and part 807 (21 CFR part 807).

FDA may also classify a device through ''De Novo'' classification, a common name for the process authorized under section 513(f)(2) of the FD&C Act. Section 207 of the Food and Drug Administration Modernization Act of 1997 (Pub. L. 105–115) established the first procedure for De Novo classification. Section 607 of the Food and Drug Administration Safety and Innovation Act (Pub. L. 112–144) modified the De Novo application process by adding a second procedure. A device sponsor may utilize either procedure for De Novo classification.

Under the first procedure, the person submits a 510(k) for a device that has not previously been classified. After receiving an order from FDA classifying the device into class III under section 513(f)(1) of the FD&C Act, the person then requests a classification under section 513(f)(2).

Under the second procedure, rather than first submitting a 510(k) and then a request for classification, if the person determines that there is no legally marketed device upon which to base a determination of substantial equivalence, that person requests a classification under section 513(f)(2) of the FD&C Act.

Under either procedure for De Novo classification, FDA is required to classify the device by written order within 120 days. The classification will be according to the criteria under section 513(a)(1) of the FD&C Act. Although the device was automatically placed within class III, the De Novo classification is considered to be the initial classification of the device.

When FDA classifies a device into class I or II via the De Novo process, the device can serve as a predicate for future devices of that type, including for 510(k)s (see section 513(f)(2)(B)(i) of the FD&C Act). As a result, other device sponsors do not have to submit a De Novo request or premarket approval application to market a substantially equivalent device (see section 513(i) of the FD&C Act, defining ''substantial equivalence''). Instead, sponsors can use the less-burdensome 510(k) process, when necessary, to market their device.

II. De Novo Classification

On November 3, 2020, FDA received Cognoa, Inc.'s request for De Novo classification of the Cognoa ASD Diagnosis Aid. FDA reviewed the request in order to classify the device under the criteria for classification set forth in section 513(a)(1) of the FD&C Act.

We classify devices into class II if general controls by themselves are insufficient to provide reasonable assurance of safety and effectiveness, but there is sufficient information to establish special controls that, in combination with the general controls, provide reasonable assurance of the safety and effectiveness of the device for its intended use (see 21 U.S.C. 360c(a)(1)(B)). After review of the information submitted in the request, we determined that the device can be classified into class II with the establishment of special controls. FDA has determined that these special controls, in addition to the general controls, will provide reasonable assurance of the safety and effectiveness of the device.

Therefore, on June 2, 2021, FDA issued an order to the requester classifying the device into class II. In this final order, FDA is codifying the classification of the device by adding 21 CFR 882.1491.[1] We have named the generic type of device pediatric Autism Spectrum Disorder diagnosis aid, and it is identified as a prescription device that is intended for use as an aid in the diagnosis of Autism Spectrum Disorder in pediatric patients.

FDA has identified the following risks to health associated specifically with this type of device and the measures required to mitigate these risks in table 1.

TABLE 1—PEDIATRIC AUTISM SPECTRUM DISORDER DIAGNOSIS AID RISKS AND MITIGATION MEASURES

Identified risks	Mitigation measures
Device failure or incorrect analysis leading to: • False positives resulting in inappropriate patient treatment and potentially delayed diagnosis of a non-ASD condition. • False negatives resulting in delayed diagnosis and patient treatment.	Clinical performance testing; Software verification, validation, and hazard analysis; and Labeling.
Use error or misinterpretation of results resulting in a, false positive or false negative.	Usability assessment, and Labeling.

FDA has determined that special controls, in combination with the general controls, address these risks to health and provide reasonable assurance of safety and effectiveness. For a device to fall within this classification, and thus avoid automatic classification in class III, it would have to comply with the special controls named in this final order. The necessary special controls appear in the regulation codified by this order. This device is subject to premarket notification requirements under section 510(k) of the FD&C Act.

At the time of classification, pediatric Autism Spectrum Disorder diagnosis aids are for prescription use only. Prescription devices are exempt from the requirement for adequate directions for use for the layperson under section 502(f)(1) of the FD&C Act (21 U.S.C. 352(f)(1)) and 21 CFR 801.5, as long as the conditions of 21 CFR 801.109 are met.

III. Analysis of Environmental Impact

The Agency has determined under 21 CFR 25.34(b) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

IV. Paperwork Reduction Act of 1995

This final order establishes special controls that refer to previously approved collections of information found in other FDA regulations and guidance. These collections of information are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3521). The collections of information in 21 CFR part 860, subpart D, regarding De Novo classification have been approved under OMB control number 0910–0844; the collections of information in 21 CFR part 814, subparts A through E, regarding premarket approval, have been approved under OMB control number 0910–0231; the collections of information in part 807, subpart E, regarding premarket notification submissions, have been approved under OMB control number 0910–0120; the collections of information in 21 CFR part 820, regarding quality system regulation, have been approved under OMB control number 0910–0073; and the collections of information in 21 CFR parts 801, regarding labeling, have been approved under OMB control number 0910–0485.

List of Subjects in 21 CFR Part 882

Medical devices.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs, 21 CFR part 882 is amended as follows:

PART 882—NEUROLOGICAL DEVICES

■ 1. The authority citation for part 882 continues to read as follows:

Authority: 21 U.S.C. 351, 360, 360c, 360e, 360j, 360l, 371.

■ 2. Add § 882.1491 to subpart B to read as follows:

§ 882.1491 Pediatric Autism Spectrum Disorder diagnosis aid.

(a) *Identification.* A pediatric Autism Spectrum Disorder diagnosis aid is a prescription device that is intended for use as an aid in the diagnosis of Autism Spectrum Disorder in pediatric patients.

(b) *Classification.* Class II (special controls). The special controls for this device are:

(1) Clinical performance testing must demonstrate that the device performs as intended under anticipated conditions of use, including an evaluation of sensitivity, specificity, positive predictive value, and negative predictive value using a reference method of diagnosis and assessment of patient behavioral symptomology.

(2) Software verification, validation, and hazard analysis must be provided. Software documentation must include a detailed, technical description of the algorithm(s) used to generate device output(s), and a cybersecurity assessment of the impact of threats and vulnerabilities on device functionality and user(s).

(3) Usability assessment must demonstrate that the intended user(s) can safely and correctly use the device.

(4) Labeling must include:

(i) Instructions for use, including a detailed description of the device, compatibility information, and information to facilitate clinical interpretation of all device outputs; and

(ii) A summary of any clinical testing conducted to demonstrate how the device functions as an interpretation of patient behavioral symptomology associated with Autism Spectrum Disorder. The summary must include the following:

(A) A description of each device output and clinical interpretation;

(B) Any performance measures, including sensitivity, specificity,

[1] FDA notes that the ''ACTION'' caption for this final order is styled as ''Final amendment; final order,'' rather than ''Final order.'' Beginning in December 2019, this editorial change was made to indicate that the document ''amends'' the Code of Federal Regulations. The change was made in accordance with the Office of Federal Register's (OFR) interpretations of the Federal Register Act (44 U.S.C. chapter 15), its implementing regulations (1 CFR 5.9 and parts 21 and 22), and the Document Drafting Handbook.

positive predictive value (PPV) and negative predictive value (NPV);

(C) A description of how the cutoff values used for categorical classification of diagnoses were determined; and

(D) Any expected or observed adverse events and complications.

(iii) A statement that the device is not intended for use as a stand-alone diagnostic.

Dated: December 27, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–28430 Filed 12–29–22; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2022–0994]

RIN 1625–AA87

Security Zone; Corpus Christi Ship Channel, Corpus Christi, TX

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary, 500-yard radius, moving security zone for a certain vessel carrying Certain Dangerous Cargoes (CDC) within the Corpus Christi Ship Channel and La Quinta Channel. The temporary security zone is needed to protect the vessels, the CDC cargo, and the surrounding waterway. Entry of vessels or persons into this zone is prohibited unless specifically authorized by the Captain of the Port Sector Corpus Christi or a designated representative.

DATES: This rule is effective without actual notice from December 30, 2022 until January 2, 2023. For the purposes of enforcement, actual notice will be used from December 26, 2022, until December 30, 2022.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email Lieutenant Commander Anthony Garofalo, Sector Corpus Christi Waterways Management Division, U.S. Coast Guard; telephone 361–939–5130, email *Anthony.M.Garofalo@uscg.mil.*

SUPPLEMENTARY INFORMATION:

I. Table of Abbreviations

CFR Code of Federal Regulations
COTP Captain of the Port Sector Corpus Christi
DHS Department of Homeland Security
FR Federal Register
NPRM Notice of proposed rulemaking
§ Section
U.S.C. United States Code

II. Background Information and Regulatory History

The Coast Guard is issuing this temporary rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ‘‘impracticable, unnecessary, or contrary to the public interest.’’ Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because it is impracticable. We must establish this security zone by December 26, 2022 to ensure security of this vessel and lack sufficient time to provide a reasonable comment period and then consider those comments before issuing the rule.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register**. Delaying the effective date of this rule would be contrary to the public interest because immediate action is needed to provide for the security of the vessel.

III. Legal Authority and Need for Rule

The Coast Guard is issuing this rule under authority in 46 U.S.C. 70034 (previously 33 U.S.C. 1231). The Captain of the Port Sector Corpus Christi (COTP) has determined that potential hazards associated with the transit of the Motor Vessel (M/V) RIAS BAIXAS KNUTSEN when loaded will be a security concern within a 500-yard radius of the vessel. This rule is needed to provide for the safety and security of the vessels, their cargo, and surrounding waterway from terrorist acts, sabotage or other subversive acts, accidents, or other events of a similar nature while they are transiting within Corpus Christi, TX, from December 26, 2022 through January 2, 2023.

IV. Discussion of the Rule

The Coast Guard is establishing four 500-yard radius temporary moving security zone around (M/V) RIAS BAIXAS KNUTSEN. The zone for the vessel will be enforced from December 26, 2022, through January 2, 2023. The duration of the zone is intended to protect the vessel and cargo and surrounding waterway from terrorist acts, sabotage or other subversive acts, accidents, or other events of a similar nature. No vessel or person will be permitted to enter the security zone without obtaining permission from the COTP or a designated representative.

Entry into the security zone is prohibited unless authorized by the COTP or a designated representative. A designated representative is a commissioned, warrant, or petty officer of the U.S. Coast Guard (USCG) assigned to units under the operational control of USCG Sector Corpus Christi. Persons or vessels desiring to enter or pass through the zone must request permission from the COTP or a designated representative on VHF–FM channel 16 or by telephone at 361–939–0450. If permission is granted, all persons and vessels shall comply with the instructions of the COTP or designated representative. The COTP or a designated representative will inform the public through Broadcast Notices to Mariners (BNMs), Local Notices to Mariners (LNMs), and/or Marine Safety Information Bulletins (MSIBs) as appropriate for the enforcement times and dates for each security zone.

V. Regulatory Analyses

We developed this rule after considering numerous statutes and Executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes and Executive orders, and we discuss First Amendment rights of protestors.

A. Regulatory Planning and Review

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits. This rule has not been designated a ‘‘significant regulatory action,’’ under Executive Order 12866. Accordingly, this rule has not been reviewed by the Office of Management and Budget (OMB).

This regulatory action determination is based on the size, duration, and location of the security zone. This rule will impact a small designated area of 500-yards around the moving vessel in the Corpus Christi Ship Channel and La Quinta Channel as the vessel transit the channel over an eight day period. Moreover, the rule allows vessels to seek permission to enter the zone.

B. Impact on Small Entities

The Regulatory Flexibility Act of 1980, 5 U.S.C. 601–612, as amended, requires Federal agencies to consider the potential impact of regulations on small entities during rulemaking. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

While some owners or operators of vessels intending to transit the temporary security zone may be small entities, for the reasons stated in section V.A above, this rule will not have a significant economic impact on any vessel owner or operator.

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

C. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

D. Federalism and Indian Tribal Governments

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect 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. We have analyzed this rule under that Order and have determined that it is consistent with the fundamental federalism principles and preemption requirements described in Executive Order 13132.

Also, this rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes. If you believe this rule has implications for federalism or Indian tribes, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section above.

E. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

F. Environment

We have analyzed this rule under Department of Homeland Security Directive 023–01 and Environmental Planning COMDTINST 5090.1 (series), which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves a moving security zone lasting for the duration of time that the M/V RIAS BAIXAS KNUTSEN is within the Corpus Christi Ship Channel and La Quinta Channel while loaded with cargo. It will prohibit entry within a 500 yard radius of M/V RIAS BAIXAS KNUTSEN while the vessel is transiting loaded within Corpus Christi Ship Channel and La Quinta Channel. It is categorically excluded from further review under L60 in Appendix A, Table 1 of DHS Instruction Manual 023–01–001–01, Rev. 1.

G. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places or vessels.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 46 U.S.C 70034, 70051, 70124; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 00170.1, Revision No. 01.2.

■ 2. Add § 165.T08–0994 to read as follows:

§ 165.T08–0994 Security Zone; Corpus Christi Ship Channel. Corpus Christi, TX.

(a) *Location.* The following area is a security zone: All navigable waters encompassing a 500-yard radius around the M/V RIAS BAIXAS KNUTSEN while the vessel is in the Corpus Christi Ship Channel and La Quinta Channel.

(b) *Enforcement period.* This section will be enforced from December 26, 2022 through January 2, 2023.

(c) *Regulations.* (1) The general regulations in § 165.33 of this part apply. Entry into the zone is prohibited unless authorized by the Captain of the Port Sector Corpus Christi (COTP) or a designated representative. A designated representative is a commissioned, warrant, or petty officer of the U.S. Coast Guard assigned to units under the operational control of USCG Sector Corpus Christi.

(2) Persons or vessels desiring to enter or pass through the zone must request permission from the COTP Sector Corpus Christi on VHF–FM channel 16 or by telephone at 361–939–0450.

(3) If permission is granted, all persons and vessels shall comply with the instructions of the COTP or designated representative.

(d) *Information broadcasts.* The COTP or a designated representative will inform the public through Broadcast Notices to Mariners (BNMs), Local Notices to Mariners (LNMs), and/or Marine Safety Information Bulletins (MSIBs) as appropriate of the enforcement times and dates for the security zone.

Dated: December 26, 2022.

J.B. Gunning,

Captain, U.S. Coast Guard, Captain of the Port Sector Corpus Christi.

[FR Doc. 2022–28471 Filed 12–29–22; 8:45 am]

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Copyright Royalty Board

37 CFR Part 385

[Docket No. 21–CRB–0001–PR (2023–2027)]

Determination of Royalty Rates and Terms for Making and Distributing Phonorecords (Phonorecords IV)

AGENCY: Copyright Royalty Board, Library of Congress.

ACTION: Final rule.

SUMMARY: The Copyright Royalty Judges publish final regulations that set rates and terms applicable during the period from January 1, 2023 through December 31, 2027, for the statutory license for making and distributing phonorecords of nondramatic musical works.

DATES:

Effective date: January 1, 2023.

Applicability date: These rates and terms are applicable during the period from January 1, 2023 through December 31, 2027.

FOR FURTHER INFORMATION CONTACT: Anita Brown, Program Specialist, (202) 707–7658, *crb@loc.gov.*

SUPPLEMENTARY INFORMATION:

Background

On August 31, 2022, the Copyright Royalty Judges (Judges) [1] received a motion stating that several participants, (Settling Parties),[2] had reached a partial settlement (Settlement) regarding the rates and terms under section 115 of the Copyright Act, namely, for Licensed Activity (as defined in 37 CFR part 385, subpart A [3]) presently addressed in subparts C & D of 37 CFR part 385 together with certain regulations of general application (*e.g.,* definitions and late fee provisions) applicable to the subpart C & D Configurations presently addressed in 37 CFR part 385, subpart A, for the 2023–2027 rate period [4] and seeking approval of that partial settlement. *See Motion to Adopt Settlement of Statutory Royalty Rates and Terms for Subpart C and D Configurations,* Docket No. 21–CRB–0001–PR (2023–2027) at 1 (eCRB 27222) [5] (Motion). The Settling Parties state that ''the settlement [ ] represents the consensus of both licensees and licensors representing the vast majority of the market for rights under section 115 for Subpart C & D Configurations.'' [6] Motion at 3.

On September 26, 2022, the Judges issued ''Order 63 to File Certification or Provide Settlement Agreements'' (eCRB 27253) (Order 63), which ordered the Settling Parties to certify that the Motion and the Proposed Regulations annexed to the Motion represent the full agreement of the Settling Parties, *i.e.,* that there are no other related agreements and no other clauses. Order 63 further ordered that if such other agreements or clauses exist, the Settling Parties shall file them.

On September 26, 2022, the Settling Parties filed a ''Joint Response to George Johnson's Motion to Compel Production of Settlement and CRB Order 63'' (eCRB 27257) (Joint Response).[7] Portions of the Joint Response, which were submitted as Restricted, are responsive to Order 63. On October 6, 2022, the Settling Parties filed a ''Joint Submission of Settling Participants Regarding Settlement Agreement'' (eCRB 27278) (Joint Submission) which removed the Restricted designation to the ''Settlement Agreement'' attached as Exhibit A to the Joint Submission. However, the Joint Response and the Joint Submission did not completely and adequately respond to Order 63.

On October 3, 2022, Google and NMPA filed ''Google and NMPA's Joint Notice of Lodging'' (eCRB 27275) (Joint Notice of Lodging), which indicated that those two parties found Order 63 unclear regarding what is meant by ''related agreements.'' Google and NMPA offered that they broadly construed Order 63's reference to ''related agreements'' to include certain letter agreements executed between Google, on the one hand, and certain music publishers and the NMPA, on the other hand, on or around the execution date of the settlement agreement. Google and NMPA indicated they will ''lodge'' such letter agreements concurrently with their Joint Notice of Lodging. Google and NMPA also indicated that they do not believe that the letter agreements are substantively related to the Settlement, and that the letter agreements simply concern Google's allocation practices to avoid double payments arising from certain direct agreements. On October 7, 2022, Google and NMPA submitted ''Google and NMPA's Joint Notice of Public Lodging'' which included public versions of letter agreements. (eCRB 27279).

On October 17, 2022, the Judges issued ''Order 64 to File Settlement Agreements and Provide Certification'' (eCRB 27284) (Order 64), which clarified the scope of Order 63 and ordered the Settling Parties to:

(1) *file* (not ''lodge'') any supplemental written agreements between Service Participants, on the one hand, and Copyright Owners and/or their affiliates, including copyright owners that they represented in this proceeding, on the other hand, that represent consideration for, or are contractually related to, the Settlement referenced in the Motion.

(2) file a detailed description of any supplemental oral agreements between Service Participants, on the one hand, and Copyright Owners and/or their affiliates, including copyright owners that they represented in this proceeding, on the other hand, that represent consideration for, or are contractually related to the Settlement referenced in the Motion, through a certification or certifications from individuals with direct knowledge of any such supplemental oral agreements.

(3) file a certification or certifications from a person or persons with first-hand knowledge stating that there are no other agreements, written or oral, beyond the Settlement, the Settlement Agreement and the filed supplemental written or oral agreements responsive to this order.

(4) explain in a supplemental brief why the remaining restricted portions of the Joint Response, apart from Exhibit A, from which the Restricted designation has been removed, would, if disclosed, interfere with the ability of the Producer to obtain like information in the future.

[1] The Copyright Royalty Judges as an institution are occasionally referenced herein as the Copyright Royalty Board (CRB).

[2] The participants who filed the motion are the National Music Publishers' Association (NMPA) and Nashville Songwriters Association International (NSAI, and collectively with NMPA, the Copyright Owners), on the one hand, and the music services, Amazon.com Services LLC, Apple Inc., Google LLC, Pandora Media, LLC, and Spotify USA Inc. (collectively, Service Participants) on the other hand.

[3] The definition of ''licensed activity,'' as the term is used in subparts C and D of 37 CFR part 385, means the delivery of musical works, under voluntary or statutory license, via Digital Phonorecord Deliveries in connection with Interactive Eligible Streams, Eligible Limited Downloads, Limited Offerings, mixed Bundles, and Locker Services. (37 CFR 385.2).

[4] The Motion refers to the rate period as ''the full time period addressed by the Proceeding.'' Motion at 1.

[5] eCRB reference numbers may be used to access relevant documents through the Copyright Royalty Board website.

[6] The Settling Parties indicate that participant George Johnson does not agree to the settlement and that participants David Powell and Brian Zisk should be dismissed because they did not file a Written Direct Statement. Motion at 3 and n. 1. Mr. Johnson filed an opposition to the motion (eCRB. No. 27239) on September 6 which the Judges consider relevant to this proposed rule.

[7] George Johnson's ''Corrected Motion to Compel Parties to Immediately Submit Actual Signed Proposed Settlement Agreement for Subpart C with Any MOUs or Side Deals here in Phonorecords IV'' was filed on September 20, 2022. (eCRB 27249).

On October 26, 2022, the Settling Parties filed a ''Joint Response to Order 64'' (eCRB 27290) (Joint Response 2).

In response to item #1 above, Joint Response 2 noted that the October 6, 2022, Joint Submission removed the Restricted designation to the ''Settlement Agreement'' and attached it within Exhibit A to Joint Response 2. In Joint Response 2, Google and NMPA also filed the aforementioned letter agreements as Exhibit B to Joint Submission 2.[8] Joint Response 2 also included the Settling Parties' representation that other than the Settlement Agreement itself, there are no other agreements responsive to Order 64.

In response to item #2 above, Joint Response 2 stated that there are no supplemental oral agreements responsive to Order 64.

In response to item #3 above, Joint Response 2 included Exhibits C–1 through C–7, certifications from a representative of each of the Settling Parties with first-hand knowledge of the Settlement Agreement and negotiations, which collectively attest that there are no other agreements, written or oral, responsive to Order 64 beyond the agreements provided as part of Joint Response 2.

In response to item #4 above, Joint Response 2 noted that the Settling Parties do not believe that there is any reason why any restricted portions of the Joint Response need to remain restricted. Therefore, the Settling Parties filed, concurrently with Joint Response 2, a revised version of the Joint Response that removes all redactions, entitled ''[Revised to Remove Redactions] Joint Response to George Johnson's Motion to Compel Production of Settlement and CRB Order 63.'' (eCRB 27289) (Revised Joint Response).

The Settling Parties offered that through Joint Response 2, and the related submissions referenced therein, the Judges have all materials necessary to publish the proposed rates and terms for public comment. The Settling Parties noted the necessary public comment and objection period, as well as potential consequences to the industry if rates and terms are not effective in time to be operationalized for the beginning of 2023, and therefore request that the Judges publish the proposed rates and terms for public comment as soon as possible.[9] Proposed regulations implementing the Settlement are attached to Joint Response 2.

On November 7, 2022, the Judges published the Settlement in the **Federal Register** and requested comments from the public. 87 FR 66976 (Nov. 7, 2022). Comments were due by December 7, 2022. The Judges received 20 comments from interested parties.[10] One participant, George Johnson (GEO) filed two comments opposing Settlement 2.[11]

Statutory Standard and Precedent

Pursuant to section 801(b)(7)(A) of the Copyright Act, the Judges have the authority to adopt settlements between some or all of the participants to a proceeding at any time during a proceeding. This section states that the Judges shall: (1) provide an opportunity to comment on the agreement to non-participants who would be bound by the terms, rates, or other determination set by the agreement; and (2) provide an opportunity to comment and to object to participants in the proceeding who would be bound by the terms, rates, or other determination set by the agreement. *See* section 801(b)(7)(A). The Judges may decline to adopt the agreement as a basis for statutory terms and rates for participants not party to the agreement if any participant objects and the Judges conclude that the agreement does not provide a reasonable basis for setting statutory terms or rates. *Id.*

Regardless of the comments of interested parties or participants, the Judges are not compelled to adopt a settlement to the extent it includes provisions that are inconsistent with the statutory license. *See* Review of Copyright Royalty Judges Determination, 74 FR 4537, 4540 (Jan. 26, 2009) (error for Judges to adopt settlement without threshold determination of legality); *see also* Review of Copyright Royalty Judges Determination, 73 FR 9143, 9146 (Feb. 19, 2008) (error not to set separate rates as required under sections 112 and 114 when parties' unopposed settlement combined rates in contravention of those statutory sections).[12]

As the Register of Copyrights (Register) observed in the 2009 review of the Judges' decision, nothing in the statute precludes rejection of any portions of a settlement that would be contrary to provisions of the applicable license or otherwise contrary to the statute. 74 FR 4540. In the instance under review by the Register, the settlement agreement purported to alter the date(s) for payment of royalties granting licensees a longer period than section 115 provided. *Id.* at 4542. The Register also noted that nothing in the statute relating to adoption of settlements precludes the Judges from considering comments of non-participants ''which argue that proposed [settlement] provisions are contrary to statutory law.'' *Id.* at 4540.

Summary of Non-Participant Comments

The comments of interested parties in this proceeding overlapped in significant aspects and are summarized as follows.

Comments in Support

The following commenters all express support for adoption of the Settlement. Black Music Action Coalition (BMAC) and Music Artists Coalition (MAC); Songwriters of North America (SONA); The Recording Academy; The Music Publishers Association of the United

[8] Joint Response 2 reiterated Google and NMPA's view that the letter agreements are not substantively related to the Settlement, and that the letter agreements simply concern Google's allocation practices to avoid double payments arising from certain direct agreements.

[9] The Judges are aware of the participants' and the public's interest in timely implementation of rates and terms, and note that the submission of partial agreements, and related materials as restricted, has been a source of unfortunate delay in consideration of the proposed settlement of statutory royalty rates and terms for subpart C and D configurations.

[10] Word Collections' Eric Goldberg (eCRB 27370); Word Collections' Jeff Price (eCRB 27369); Black Music Action Coalition (BMAC) and Music Artists Coalition (MAC) (eCRB 27369); Songwriters of North America (SONA) (eCRB 27367); The Recording Academy (eCRB 27365); The Music Publishers Association of the United States (MPA) (eCRB 27364); Eugene ''Lambchops'' Curry (eCRB 27357); Songwriters Guild of America, Inc. (SGA), Society of Composers & Lyricists (SCL), and Music Creators North America (MCNA), and the individual music creators Rick Carnes and Ashley Irwin (together Independent Music Creators) (eCRB 27358); Helienne Lindvall, David Lowery and Blake Morgan (together Writers) (eCRB 27356); Abby North (eCRB 27355); Gwendolyn Seale (eCRB 27354); Austin Texas Musicians (eCRB 27353); Michelle Shocked (eCRB 27352);; The Association of Independent Music Publishers (AIMP) (eCRB 27349); Production Music Association (PMA) (eCRB 27340); Ross Golan (eCRB 27336); William Evans (eCRB 27333); The 100 Percenters (eCRB 27329); and The Church Music Publishers Association of the United States (CMPA) (eCRB 27326); and Upward Bound Music Company (eCRB 27317).

[11] On September 6, 2022, before the Judges published the Settlement for comment, GEO filed a *Response in Opposition to the Subpart C Proposed Settlement* (eCRB 27239) (GEO Opposition). On November 7, 2022, after the Judges published the Settlement for comment, GEO filed *Comments and Second Response in Opposition to the Subpart C Proposed Settlement in Phonorecords IV* (eCRB 27371) (GEO Second Opposition), which objects to adoption of the Settlement and included in an Exhibit GEO's prior *Response in Opposition to the Subpart C Proposed Settlement.* GEO also states his desire to join (entirely or partially) with several commenters that oppose aspects of the Settlement.

[12] The Register found that a ''paucity of evidence'' in the record to support a determination of separate rates for the separate licenses ''does not dispatch the . . . Judges' statutory obligations.'' Review of Copyright Royalty Judges Determination, 73 FR 9143, 9145 (Feb. 19, 2008). The Register noted that the Judges have subpoena power to compel witnesses to appear and give testimony. *Id.*

States (MPA); The Association of Independent Music Publishers (AIMP); Production Music Association (PMA); Ross Golan; The 100 Percenters; and The Church Music Publishers Association of the United States (CMPA).

These commenters express generally positive assessment of the Settlement. However, several of these comments, while supportive of adoption of the Settlement, take issue with the current extent of regulation of musical works and with aspects of the rate setting process, which are beyond the scope of the Judges' consideration of the Settlement.

Comments in Opposition

Word Collections' Eric Goldberg offers a series of comparisons of historical mechanical per play rates to the growth in 115 licensed music services' Subscriber Counts, Service Revenue, and Total Content Costs (''meaning the amount paid to labels for sound recording rights''). Mr. Goldberg also presents predictions of mechanical per play rates over the *Phonorecords IV* rate period under the terms of the Settlement. His analysis is intended to support his view that, as a matter of equity, the headline rates (applicable to service revenue) should be increased further to give songwriters parity with the music services and record labels who depend upon the songwriters' creative works of authorship. Word Collections' Eric Goldberg at 1–6.

Word Collections' Jeff Price reiterates aspects of the comment from Word Collections' Eric Goldberg, advancing the notion that any increase realized by songwriters and musical work owners under the settlement would not keep pace with the cost of living, inflation, or with the benefits realized by music services or sound recording copyright owners. Mr. Price offers that a headline rate of 25% combined with the elimination of several deductions from attributable revenue would properly compensate songwriters and copyright owners. Word Collections' Jeff Price at 6–7.

Mr. Price states that his comment is intended to provide information to the Judges regarding the NMPA and who it represents when taking into consideration the proposed Settlement. Mr. Price offers that NMPA represents less than 2% of U.S. (and rest of the world) music publishers and suggests that NMPA's interests are not aligned with 98% of music publishers. Mr. Price goes on to indicate that major labels, Sony, Universal and Warner, control equity positions in music services, and that these three entities own and/or control the major record labels, the associated sound recordings, the major music publishers, and the associated musical composition copyrights. Mr. Price offers that the intertwined relationships create conflicts of interest. Specifically, Mr. Price points to conflicts of interests that were noted in relationship to a prior proposed settlement in this proceeding, and a suggested conflict of interest in relationship to SoundExchange (the designated collective for royalties under specific statutory licenses for sound recordings). Word Collections' Jeff Price at 1–2.

Mr. Price suggests that the NMPA and or its members have self-negotiated to some degree to determine what musical work copyright owners should be paid in the future. Word Collections' Jeff Price at 2. Mr. Price then addresses issues surrounding the scope or availability of the section 115 license, in relation to certain licensees, suggesting that in the future there may be an informative and robust market for willing buyer willing seller negotiations for mechanical. *Id.* at 2–6.

Songwriters Guild of America, Inc. (SGA), Society of Composers & Lyricists (SCL), and Music Creators North America (MCNA), and the individual music creators Rick Carnes and Ashley Irwin (together Independent Music Creators) [13] comment in opposition, asking the Judges to modify or reject the Settlement in its present form as a necessity for providing economic justice for music creators. Independent Music Creators at 2. Independent Music Creators opine that the Settlement represents insufficient and unreasonable limited increases in streaming rates over the next five years, especially in light of anticipated inflation. *Id.* at 10. Independent Music Creators acknowledge that the Settlement includes elements other than a headline percentage of revenue, and that these other elements, such as the total content cost (TCC) component and fixed per subscriber elements, have increased far more than the headline rate. However, Independent Music Creators criticize these details as complex ancillary terms, which lack plain language explanations. Furthermore, Independent Music Creators offer that the possibility of increases in licensees' subscription revenue that may positively impact mechanical royalties under the settlement, or offset inflationary losses, are at best speculative and at worst specious. *Id.* at 12. They instead voice preference for an approach based on cost of living adjustment principles, including what they offer as a necessary application of cost of living adjustments to royalty pools within the existing greater than/lesser of rate structure. *Id.*

Independent Music Creators warn of conflicts and complications surrounding the streaming royalty rate negotiations, and potential self-dealing. They offer their suspicion that major music publisher-affiliated record companies exercised undue influence on the Settlement. *Id.* at 14. Independent Music Creators criticize music publishers' silence regarding the traditional ratio of label versus publisher share of revenue, and point to the opinions of Merck Mercuriadis, an executive at the music publisher, Hipgnosis, that major music publishers are not free to do what's in the best interests of their constituency, because they're owned and controlled by their respective major recorded music companies. *Id.* at 15.

Ultimately, Independent Music Creators do not indicate that specific undue influence or conflicts of interest impacted the Settlement but suggest that the possibility raises questions as to whether the Settlement can reliably be shown to have been arrived at with adequate and unconflicted representation of music creator and publisher interests, and whether the results reached following such negotiations are reasonable. *Id.* at 17. Independent Music Creators also urge that the Judges address (1) whether the Settling Parties should be required to explain in plain language how their streaming royalty rate settlement terms will avoid catastrophic losses in value due to inflation over the next five years; (2) whether a cost of living adjustment provision is warranted, as such provisions have been included in several other recently negotiated rate agreements approved by the CRB, and; (3) whether the proposed settlement agreement was negotiated with adequate and unconflicted representation of music creator and publisher interests, leading to results that provide a reliably reasonable basis for the setting of fair and equitable statutory streaming rates and terms. *Id.* at 18.

Songwriters Helienne Lindvall, David Lowery, and Blake Morgan (Writers) [14] support the Settlement as far as it goes

[13] The Independent Music Creators' state that their comments are endorsed by Alliance for Women Film Composers (AWFC), Screen Composers Guild of Canada (SCGC), Songwriters Association of Canada (SAC), Asia-Pacific Music Creators Alliance (APMA), Music Answers (M.A.), Fair Trade Music International (FTMI), Pan-African Composers and Songwriters Alliance (PACSA), and Alliance of Latin American Composers & Authors (AlcaMusica).

[14] Writers' comment was submitted by Christian L. Castle as Counsel.

but with some reservations. Writers at 1. Writers express concern that inflation may diminish the rates for copyright owners. They argue that the lack of a cost of living adjustment within the rate structure is wrong and arbitrary, particularly since they do not perceive any justification has been given. Writers dispute the view that because copyright owners receive a share of revenue from the statutory licensees that increasing revenue from increases in subscription prices or number of subscribers will accrue to copyright owners benefit. They argue that a cost of living adjustment would provide more effective protection against inflation. Writers suggest that the Judges could add a new step in the proposed settlements regulations, where a cost of living adjustment would be applied after the per work royalty allocation is determined. *Id.* at 5–7.

Writers posit that the rate calculation formula in the Settlement is unduly complex. While Writers acknowledge some compelling reasons as to why complexity developed, they refer to the calculation of streaming mechanicals set forth in the Settlement as mind-numbing in complexity. They go on to allege that the complexity is nonsensical. *Id.* at 8–11.[15]

Writers then address late fees, which they deem similar to credit card interest. They argue that late fees should be treated as an additional royalty payment under any publishing agreement. Otherwise, the Writers allege, a late fee might be treated as a catalog-wide penalty and that a copyright owner collecting the late fee could argue should be retained for its own account, without attribution to specific works or songwriters. *Id.* at 12.

Writers argue for the clarification of the ''overtime adjustment'' language such that the long-song adjustment is a bonus and not a penalty. They cite to the version of section 115 that was in force prior to the enactment of the MMA for the principle that copyright owners should not bear the cost of the long song bonus through a reduction in the statutory rates that may otherwise be applicable to songs that fall below the overtime adjustment. *Id.* at 13–15.

Writers request that the Judges address the possibility that the Settlement would allow licensees to include activity in the denominator (in step 4) that should not be there (such as podcasts or spoken word recordings). They offer that once such undue plays are included in that denominator it is very difficult to remove these non-royalty bearing tracks and restate all earnings. *Id.* at 15–16.

Abby North expresses some favorable views toward the settlement, but offers her criticism of the delays in the final implementation of rate setting proceedings, in the current proceeding and others. She takes issue with the lack of transparency regarding to submissions related to the Settlement and resulting delays. Abby North at 1. Ms. North states that the section 115 rates and terms must include a cost of living adjustment and that the Settling Parties should agree to including such adjustments. She disputes that music services' subscription prices and number of subscribers would provide an organic cost of living adjustment. *Id.* at 2.

Gwendolyn Seale, a music lawyer who represents songwriters, offers comments on her own behalf opposing the settlement. Ms. Seale takes issue with adoption of the Settlement as it would thwart application of the willing buyer, willing seller rate setting standard that would have been applied in a determination made by the Judges absent settlement. Gwendolyn Seale at 2–3. She also alleges that the Settlement is unduly complex and results in troubling trends in resulting the per play allocations. *Id* at 3–4.

Ms. Seale suggests that while the Judges may not be able to fix the rate formula, the Judges should integrate a cost of living adjustment to be applied to the ''payable royalty pool.'' She suggests adding a cost of living adjustment at the end-result following all of the greater and lesser of calculations and the removal of the performance royalties from the ''all-in royalty pool.'' *Id.* at 5. Ms. Seale also takes issue with several procedures and delays occurring within the proceeding process. *Id* at 3, 5–6.

Michelle Shocked submits comments that ''agree with Participant George Johnson's September 6, 2022 objections for the same following reasons.'' Michelle Shocked at 1–4. Those objections from George Johnson are set forth in the next section below. In addition, Ms. Shocked raises issues about certain music services' alleged lack of compliance with the section 115 license and other alleged piracy of her works. *Id.* at 4–6.

Austin Texas Musicians request that the Judges include a cost of living adjustment. Austin Texas Musicians at 1. Eugene ''Lambchops'' Curry, William Evans and Upward Bound Music Company do not pointedly address the Settlement, but instead propose various alternative rates ranging from 0.12 cent per stream to $3.00 per stream. Eugene Curry at 1–2; William Evans at 1; Upward Bound at 1–3.

Mr. Johnson's Opposition to the Settlement

Proceeding participant George Johnson (GEO) objects to the Settlement in part because, in his view, it suffers from the same issues that the Judges found to be a basis for their March 30, 2022 withdrawal and refusal to adopt another proposed settlement, namely that a) the settlement has no inflation adjustment for what he deems to be a static rate; b) it suffers from same self-dealing and conflicts of interest concerns; and c) the settlement may possibly be related to an undisclosed side deal. GEO Second Opposition at 15.

While GEO refers to the Settlement offer as the bare minimum, he also asserts that the 15.35% percent of revenue element within the Settlement for 2027 is too low, and that 20% to 25% would be a reasonable percent of revenue element. GEO Second Opposition at 29, 13. GEO maintains that the 15.1% percent of revenue element within the Settlement for 2023 is not an increase in value, and that the 15.1% to 15.35% percent of revenue elements for the rate period is essentially a static rate, which GEO indicates is in tension with the Judges' March 30, 2022 withdrawal and refusal to adopt another proposed settlement. *Id.* GEO questions why neither the percent of revenue element nor the per-subscriber elements are indexed for inflation, suggesting that is also in tension with the Judges' March 30, 2022 decision. *Id.*

GEO expresses concern that adoption of the Settlement may thwart application of the willing buyer, willing seller rate setting standard that would have been applied in a determination made by the Judges absent settlement. *Id.* at 14.

GEO also includes several broad criticisms regarding value realized by investors in affected businesses as well as the salaries of executives at such businesses. *Id.* at 15. He adds accusations of price fixing and antitrust concerns across the music business. *Id.* at 16. GEO suggests that the Settlement does not adequately account for revenue that licensees may realize through their sale of data and advertising. *Id.*

GEO alleges that Google and NMPA's Joint Notice of Public Lodging, filed to update their response to Order 63 to File Certification or Provide Settlement Agreements, shows that ''the 3 record labels'' are using direct licenses for themselves with music services while using the CRB process to price-fix all of

[15] Writers also take issue with a number of procedures in CRB proceedings, which are beyond the scope consideration of the settlement at issue.

their competitors. *Id.* at 17–18, 20–21. GEO suggests that major publishers' direct licenses reflect different rates and terms than the statutory rates proposed in the Settlement. He also claims that non-disclosure agreements prevent anyone from knowing the rates and terms in those direct licenses. *Id.* at 18.

GEO attempts to compare the Settlement to a vaguely referenced direct deal involving Sony from 2011, covering unspecified rights with an unknown party, which apparently is not in the record of this proceeding. GEO's cryptic reference to a 2011 deal for unspecified rights is apparently meant to suggest that there might be additional undisclosed consideration in relation to the Settlement. *Id.* at 19–20.

GEO also includes alternative rate proposals and urges the Judges to abolish what he refers to as a ''free limited download loophole'' or a ''free and unlimited limited downloads loophole.'' *Id* at 2, 3. GEO further addresses this matter as an element within his WDS which proposes to plug the free and unlimited limited downloads loophole. *Id.* at 2, 11–15.[16]

Judges' Analysis and Conclusions

Chapter 8 of the Copyright Act encourages parties to enter into settlement negotiations, ultimately the decision as to whether a contested settlement should be approved on motion is subject to the Judges' discretion, informed by the submissions of the Settling Parties and the commenters, and by the Judges' application of the law to the facts. Section 801(b)(7)(A) is clear that the Judges have the authority to adopt settlements between some or all of the participants to a proceeding at any time during a proceeding, so long the relevant parties are given an opportunity to comment and object. 17 U.S.C. 801(b)(7)(A). The Judges may decline to adopt the agreement as a basis for statutory terms and rates for participants not party to the agreement if any participant objects and the Judges conclude that the agreement does not provide a reasonable basis for setting statutory terms or rates. *Id.* at 801(b)(7)(A).

The Judges provided the requisite opportunity for comment and received GEO's opposition as well as the above-noted comments for and against the Settlement. Having considered these submissions in their entirety, the Judges find no persuasive legal or economic arguments that convince the Judges to reject the proposed settlement reached voluntarily between the Settling Parties.

Only one *participant* in this proceeding, GEO, objected to the Settlement. As shown by the foregoing synopsis, however, GEO's objections did not come to the Judges in a vacuum. The statute requires publication of a settlement proposal and solicitation of comments from interested parties—parties who would be bound by the proposed rates and terms. Interested parties' comments are filed in the record of the proceeding and the Judges analyze those comments even though the Judges do not base rejection of a settlement solely on negative comments from non-participants.

From the perspective of some independent songwriters and copyright owners, the proposed rates might seem inadequate. The Judges recognize that several commenters proposed alternative rates that they prefer, including alternative methods for inserting inflation adjustments. However, while the Judges may decline to adopt a settlement, the Judges are not empowered to modify the Settlement, such as by adding requested adjustments. The Settlement is what is before the Judges for consideration, not alternative rates or proposals for alternative procedures.[17] The Judges specifically recognize that some comments take issue with existing aspects of participation in rate proceedings before the Judges.[18] Additionally, the present settlement consideration process is not the forum to fully consider and address matters involving statements of account,[19] an area which the U. S, Copyright Office and the Judges share an interest.[20]

While there may be dispute as to the extent to which the Copyright Owners as Settling Parties represent the copyright owner community overall, the Judges accept that the Copyright Owners have an interest in the vast majority of the uses of rights under section 115 for Subpart C & D Configurations. Furthermore, the Judges accept that the proposed rates and terms were negotiated on behalf of the vast majority of parties that historically have participated in section 115 proceedings before the Judges. The Settling Parties clearly concluded that the rates and terms were acceptable to both sides. Furthermore, as addressed below, the negotiations occurred absent several of the aspects that led the Judges to refuse to adopt a separate proposed settlement.

The facts and analysis that led the Judges to conclude that another proposed settlement in this proceeding did not provide a reasonable basis for setting statutory rates and terms are distinguishable from those surrounding the Settlement before them now. In the current consideration of the Settlement, the mechanical rates represent an increase from prior rates across significant steps of the rate setting formula, including the headline rate applicable to service revenue, the percentage of Total Content Costs, and fixed per subscriber elements within the Settlement, *e.g.* Royalty Floors. In other words, the rates do not remain unchanged. They are not frozen, despite the fact that they retain a rate *structure,* that some do not favor. The Judges clarify that they do not consider the structure of the Settlement to be unreasonable, and that they have found similar structure appropriate in other proceedings.

While some songwriters or copyright owners may be confused by the royalties or statements of account, the price discriminatory structure and the associated levels of rates in settlement do not appear gratuitous, but rather designed, after negotiations, to establish a structure that may expand the revenues and royalties to the benefit of copyright owners and music services alike, while also protecting copyright owners from potential revenue diminution. This approach and the resulting rate setting formula is not unreasonable. Indeed, when the market

[16] GEO's opposition to the ''free and unlimited limited downloads loophole'' may, on its face, appear somewhat vague. However, GEO's proposal appears to relate to an issue and proposal raised more precisely in Copyright Owners' WDS, intended to close a hole in the terms that could be seen as leaving some uses without a rate. Restricted Downloads have been defined as any downloads that are not permanent, including Eligible Limited Downloads. However, past regulations (and seemingly those set forth in the Settlement) do not provide a rate for Restricted Downloads. Copyright Owners' WDS proposed revising the definitions to maintain the allowance for zero rate Restricted Downloads solely in connection with Purchased Content Locker Services and set a rate for other Restricted Downloads equal to the penny rate for Permanent Downloads. Copyright Owners WDS at 23–24.

[17] Concerns about enforcement of infringement of licensable works or eligibility for the section 115 license are also outside the scope of the consideration of the Settlement.

[18] Certain of the procedural issues raised by commenters have been addressed in part through a recent response to an inquiry from the Senate Judiciary Committee. *See, https://www.crb.gov/docs/CRB-Response-2022-11-25-Letter-to-Senators-FINAL.pdf.*

[19] Absent specific briefing in relation to any requested clarification or correction, the Judges interpret the regulations to clarify that Plays in the denominator (in step 4) is limited to Covered Activity, as used in the regulatory definitions and references to the term as defined section 115(e)(7).

[20] The Judges specifically find that the application and allocation of the overtime adjustment and late fees as set forth in the Settlement is not unreasonable. The Judges further observe that allocation of late fees may be addressed through the contracts between songwriters and their publishers.

itself is complex, it is unsurprising that the regulatory provisions would resemble the complex terms in a commercial agreement negotiated in such a setting. For the Judges to demand simplicity in this context would be to sacrifice the specificity that an effectively competitive market requires. The Judges also observe that one of the benefits of a collective entity (the MLC in this case) is that it possesses the expertise and resources to identify and explain how royalties are computed and distributed.

In the current consideration of the Settlement, the Judges ordered disclosure of relevant supplemental agreements. The Judges took appropriate steps to ensure that such agreements have been properly revealed to the Judges and to the public. This is an important distinction from the Judges' consideration a settlement where related agreements were hidden or opaque.[21]

The issue of potential conflicts of interest remains to some degree, as some publishers represented by NMPA have cross ownership relationships with record labels, some of which have or had equity interests with music services. However, as the Judges have repeatedly observed, conflicts are inherent if not inevitable in the existing composition of certain negotiating parties. No party opposing the Settlement has presented persuasive evidence of misconduct or conduct that would sufficiently indicate that rates or terms are inconsistent with those that would be set in an effectively competitive market. The corporate relationships alone do not suffice as probative evidence of wrongdoing or of rates or terms that are inconsistent with the performance of an effectively competitive market. Indeed, the Judges have observed zealous advocacy throughout the proceeding, which has appeared to affect the settlement, thus mitigating the effect of any possible collusion such as suggested in the comments and the objection. The Judges, therefore, do not find that present alleged conflicts present sufficient reason to doubt the reasonableness of the settlement at issue as a basis for setting statutory rates and terms.

The Judges do not conclude that the Settlement agreement, reached voluntarily between the Settling Parties, fails to provide a reasonable basis for setting statutory terms and rates for licensing nondramatic musical works to manufacture and distribute phonorecords. The entirety of the record before the Judges, including the arguments GEO and other commenters presented, is insufficient for the Judges to determine that the agreed rates and terms are unreasonable.

In making this finding, the Judges are not indicating that arguments for differing approaches to address inflation in the Settlement are entirely without merit. However, the Judges find some of the proposals for cost of living adjustments advanced in the comments to be questionable. In short, the Judges do not find it unreasonable, in this case, for the Settlement to not include yearly adjustments for inflation.

In making this finding, the Judges observe the broad increases within the Settlement, including the headline percentage rate applicable to Service Revenue, the percentage of Total Content Costs, and each of the fixed per subscriber elements. The Judges find that the structure and increases are a reasonable approach to providing an organic cost of living adjustment. The Judges also observe that agreements such as the Settlement are arrived upon in part to avoid costly and uncertain litigation, which would involve a number of disputed issues. Securing specific inflation adjustments is but one of several provisions that may be bargained for, and treatment of that issue is bound-up with the entirety of the parties' negotiated compromises. In this context, the Judges find no persuasive reason to determine that the absence of yearly inflation adjustments is unreasonable or should otherwise justify a rejection of the Settlement. The Judges also note that while the willing buyer willing seller standard was not expressly applied as it would be in a full proceeding, the operable rate standard exists as a relevant factor surrounding the Settlement.

The Judges also reviewed the Settlement with regard to whether any portions would be contrary to provisions of the applicable license or otherwise contrary to the statute, pursuant to the Register's prior rulings. *See, e.g.,* Review of Copyright Royalty Judges Determination, 74 FR 4537, 4540 (Jan 26, 2009). Upon such review, the Judges see no basis to conclude that the Settlement is contrary to law. Therefore, the Judges adopt the proposed regulations that codify the Settlement.[22]

The Judges adopt the proposed rates and terms industry-wide for Subparts C and D Configurations.

List of Subjects in 37 CFR Part 385

Copyright, Phonorecords, Recordings.

For the reasons set forth in the preamble, the Copyright Royalty Judges amend 37 CFR part 385 as follows:

PART 385—RATES AND TERMS FOR USE OF NONDRAMATIC MUSICAL WORKS IN THE MAKING AND DISTRIBUTING OF PHYSICAL AND DIGITAL PHONORECORDS

■ 1. The authority citation for part 385 continues to read as follows:

Authority: 17 U.S.C. 115, 801(b)(1), 804(b)(4).

■ 2. Revise subpart A to read as follows:

Subpart A—Regulations of General Application

Sec.
385.1 General.
385.2 Definitions.
385.3 Late payments.
385.4 Recordkeeping for promotional or free trial non-royalty-bearing uses.

§ 385.1 General.

(a) *Scope.* This part establishes rates and terms of royalty payments for the use of nondramatic musical works in making and distributing of physical and digital phonorecords in accordance with the provisions of 17 U.S.C. 115. This subpart contains regulations of general application to the making and distributing of phonorecords subject to the section 115 license.

(b) *Legal compliance.* Licensees relying on the compulsory license detailed in 17 U.S.C. 115 shall comply with the requirements of that section, the rates and terms of this part, and any other applicable regulations. This part describes rates and terms for the compulsory license only.

(c) *Interpretation.* This part is intended only to set rates and terms for situations in which the exclusive rights of a Copyright Owner are implicated and a compulsory license pursuant to 17 U.S.C. 115 is obtained. Neither this part nor the act of obtaining a license under 17 U.S.C. 115 is intended to express or imply any conclusion as to the circumstances in which a user must obtain a compulsory license pursuant to 17 U.S.C. 115.

(d) *Relationship to voluntary agreements.* The rates and terms of any license agreements entered into by Copyright Owners and Licensees

[21] As the Judges have noted, the submission of partial agreements, and related materials as restricted, has been a source of unfortunate delay in consideration of the proposed settlement of statutory royalty rates and terms for subpart C and D configurations.

[22] The Judges observe that GEO appears to have requested a rate setting for activity that may not be addressed in the Settlement, which he describes as an "unlimited limited download." The Judges intend to request additional briefing from the Participants as to whether and how this proceeding may address such activity.

relating to use of musical works within the scope of those license agreements shall apply in lieu of the rates and terms of this part.

§ 385.2 Definitions.

Unless otherwise specified, capitalized terms in this part shall have the same meaning given to them in 17 U.S.C. 115(e). For the purposes of this part, the following definitions apply:

Accounting Period means the monthly period specified in 17 U.S.C. 115(c)(2)(I) and in 17 U.S.C. 115(d)(4)(A)(i), and any related regulations, as applicable.

Active Subscriber means an End User of a Bundled Subscription Offering who has made at least one Play during the Accounting Period.

Affiliate means an entity controlling, controlled by, or under common control with another entity, except that an affiliate of a Sound Recording Company shall not include a Copyright Owner to the extent it is engaging in business as to musical works.

Artificial Accounts are accounts that are disabled or terminated for having engaged in User Manipulation or other fraudulent activity and for which any subscription revenues are refunded or otherwise not received by the Service Provider.

Bundle means a combination of a Subscription Offering providing Eligible Interactive Streams and/or Eligible Limited Downloads and one or more other products or services having more than token value, purchased by End Users in a single transaction (*e.g.,* where End Users make a single payment without separate pricing for the Subscription Offering component).

Bundled Subscription Offering means a Subscription Offering providing Eligible Interactive Streams and/or Eligible Limited Downloads included within a Bundle.

Copyright Owner(s) are nondramatic musical works copyright owners who are entitled to royalty payments made under this part pursuant to the compulsory license under 17 U.S.C. 115.

Digital Phonorecord Delivery has the same meaning as in 17 U.S.C. 115(e)(10).

Eligible Interactive Stream means a Stream that is an Interactive Stream as defined in 17 U.S.C. 115(e)(13).

Eligible Limited Download means a Limited Download as defined in 17 U.S.C. 115(e)(16) that is only accessible for listening for—

(1) An amount of time not to exceed one month from the time of the transmission (unless the Licensee, in lieu of retransmitting the same sound recording as another Eligible Limited Download, separately, and upon specific request of the End User made through a live network connection, reauthorizes use for another time period not to exceed one month), or in the case of a subscription plan, a period of time following the end of the applicable subscription no longer than a subscription renewal period or three months, whichever is shorter; or

(2) A number of times not to exceed 12 (unless the Licensee, in lieu of retransmitting the same sound recording as another Eligible Limited Download, separately, and upon specific request of the End User made through a live network connection, reauthorizes use of another series of 12 or fewer plays), or in the case of a subscription transmission, 12 times after the end of the applicable subscription.

End User means each unique person that:

(1) Pays a subscription fee for an Offering during the relevant Accounting Period; or

(2) Makes at least one Play during the relevant Accounting Period.

Family Plan means a discounted Subscription Offering to be shared by up to six members of the same family or household for a single subscription price.

Free Trial Offering means a subscription to a Service Provider's transmissions of sound recordings embodying musical works when—

(1) Neither the Service Provider, the Sound Recording Company, the Copyright Owner, nor any person or entity acting on behalf of or in lieu of any of them receives any monetary consideration for the Offering;

(2) The usage does not exceed 45 days per subscriber per one-year period, which days may be nonconsecutive;

(3) In connection with the Offering, the Service Provider complies with the recordkeeping requirements in § 385.4 or superseding Copyright Office recordkeeping requirements;

(4) The Free Trial Offering is made available to the End User free of any charge; and

(5) The Service Provider offers the End User periodically during the trial an opportunity to subscribe to, and/or auto-renews the End User into, a non-Free Trial Offering of the Service Provider.

GAAP means U.S. Generally Accepted Accounting Principles in effect at the relevant time, except that if the U.S. Securities and Exchange Commission permits or requires entities with securities that are publicly traded in the U.S. to employ International Financial Reporting Standards in lieu of Generally Accepted Accounting Principles, then that entity may employ International Financial Reporting Standards as ''GAAP'' for purposes of this subpart.

Licensee means any entity availing itself of the compulsory license under 17 U.S.C. 115 to use copyrighted musical works in the making or distributing of physical or digital phonorecords.

Licensed Activity as the term is used in subparts C and D of this part, means Covered Activity, under voluntary or statutory license, in the form of Eligible Interactive Streams, Eligible Limited Downloads, and Restricted Downloads.

Locker Service means an Offering providing digital access to sound recordings of musical works in the form of Eligible Interactive Streams, Permanent Downloads, Restricted Downloads or Ringtones where the Service Provider has reasonably determined that the End User has purchased or is otherwise in possession of the subject phonorecords of the applicable sound recording prior to the End User's first request to use the sound recording via the Locker Service. The term Locker Service does not mean any part of a Service Provider's products otherwise meeting this definition, but as to which the Service Provider has not obtained a section 115 license.

Mixed Service Bundle means an Offering providing Licensed Activity consisting of Eligible Interactive Streams or Eligible Limited Downloads that meets all of the following criteria:

(1) The Offering is made available to End Users only in combination (*i.e.,* the Offering is not available on a standalone basis) with one or more products or services (including services subject to other subparts) of more than token value as part of one transaction for which End Users make a payment without receiving pricing for the Offering separate from the product(s) or service(s) with which it is made available.

(2) The Offering is made available by a Service Provider that also offers End Users a separate, standalone Subscription Offering.

(3) The Offering offers End Users less functionality relative to that separate, standalone Subscription Offering. Such lesser functionality may include, but is not limited to, limitations on the ability of End Users to choose to listen to specific sound recordings on request or a limited catalog of sound recordings.

(4) Where an Offering could qualify or be considered as either a Bundled Subscription Offering or a Mixed Service Bundle, such Offering shall be deemed a Mixed Service Bundle for the purpose of calculating and paying royalties under subpart C of this part.

Music Bundle means two or more of physical phonorecords, Permanent Downloads or Ringtones delivered as part of one transaction (*e.g.,* download plus ringtone, CD plus downloads). In the case of Music Bundles containing one or more physical phonorecords, the Service Provider must sell the physical phonorecord component of the Music Bundle under a single catalog number, and the musical works embodied in the Digital Phonorecord Delivery configurations in the Music Bundle must be the same as, or a subset of, the musical works embodied in the physical phonorecords; provided that when the Music Bundle contains a set of Digital Phonorecord Deliveries sold by the same Sound Recording Company under substantially the same title as the physical phonorecord (*e.g.,* a corresponding digital album), the Service Provider may include in the same bundle up to 5 sound recordings of musical works that are included in the stand-alone version of the set of digital phonorecord deliveries but not included on the physical phonorecord. In addition, the Service Provider must permanently part with possession of the physical phonorecord or phonorecords it sells as part of the Music Bundle. In the case of Music Bundles composed solely of digital phonorecord deliveries, the number of digital phonorecord deliveries in either configuration cannot exceed 20, and the musical works embodied in each configuration in the Music Bundle must be the same as, or a subset of, the musical works embodied in the configuration containing the most musical works.

Offering means a Service Provider's engagement in Licensed Activity covered by subparts C and D of this part.

Paid Locker Service means a Locker Service for which the End User pays a fee to the Service Provider.

Performance Royalty means the license fee payable for the right to perform publicly musical works in any of the forms covered by subparts C and D this part.

Permanent Download has the same meaning as in 17 U.S.C. 115(e)(24).

Play means an Eligible Interactive Stream, or a play of an Eligible Limited Download, lasting 30 seconds or more and, if a track lasts in its entirety under 30 seconds, an Eligible Interactive Stream or a play of an Eligible Limited Download of the entire duration of the track. A Play excludes an Eligible Interactive Stream or a play of an Eligible Limited Download caused by User Manipulation.

Promotional Offering means a digital transmission of a sound recording, in the form of an Eligible Interactive Stream or an Eligible Limited Download, embodying a musical work, the primary purpose of which is to promote the sale or other paid use of that sound recording or to promote the artist performing on that sound recording and not to promote or suggest promotion or endorsement of any other good or service and

(1) A Sound Recording Company is lawfully distributing the sound recording through established retail channels or, if the sound recording is not yet released, the Sound Recording Company has a good faith intention to lawfully distribute the sound recording or a different version of the sound recording embodying the same musical work;

(2) The Service Provider is in compliance with the recordkeeping requirements of § 385.4 or superseding Copyright Office recordkeeping requirements;

(3) For Eligible Interactive Streams of segments of sound recordings not exceeding 90 seconds, the Sound Recording Company delivers or authorizes delivery of the segments for promotional purposes and neither the Service Provider nor the Sound Recording Company creates or uses a segment of a sound recording in violation of 17 U.S.C. 106(2) or 115(a)(2);

(4) The Promotional Offering is made available to an End User free of any charge; and

(5) The Service Provider provides to the End User at the same time as the Promotional Offering Stream an opportunity to purchase the sound recording or the Service Provider periodically offers End Users the opportunity to subscribe to a paid Offering of the Service Provider.

Purchased Content Locker Service means a Locker Service made available to End User purchasers of Permanent Downloads, Ringtones, or physical phonorecords at no incremental charge above the otherwise applicable purchase price of the Permanent Downloads, Ringtones, or physical phonorecords acquired from a qualifying seller. With a Purchased Content Locker Service, an End User may receive one or more additional phonorecords of the purchased sound recordings of musical works in the form of Permanent Downloads or Ringtones at the time of purchase, or subsequently have digital access to the purchased sound recordings of musical works in the form of Eligible Interactive Streams, additional Permanent Downloads, Restricted Downloads, or Ringtones.

(1) A qualifying seller for purposes of this definition is the entity operating the Service Provider, including Affiliates, predecessors, or successors in interest, or—

(2) In the case of Permanent Downloads or Ringtones, a seller having a legitimate connection to the locker service provider pursuant to one or more written agreements (including that the Purchased Content Locker Service and Permanent Downloads or Ringtones are offered through the same third party); or

(3) In the case of physical phonorecords:

(i) The seller of the physical phonorecord has an agreement with the Purchased Content Locker Service provider establishing an integrated offer that creates a consumer experience commensurate with having the same Service Provider both sell the physical phonorecord and offer the integrated locker service; or

(ii) The Service Provider has an agreement with the entity offering the Purchased Content Locker Service establishing an integrated offer that creates a consumer experience commensurate with having the same Service Provider both sell the physical phonorecord and offer the integrated locker service.

Relevant Page means an electronic display (for example, a web page or screen) from which a Service Provider's Offering consisting of Eligible Interactive Streams or Eligible Limited Downloads is directly available to End Users, but only when the Offering and content directly relating to the Offering (*e.g.,* an image of the artist, information about the artist or album, reviews, credits, and music player controls) comprises 75% or more of the space on that display, excluding any space occupied by advertising. An Offering is directly available to End Users from a page if End Users can receive sound recordings of musical works (in most cases this will be the page on which the Eligible Limited Download or Eligible Interactive Stream takes place).

Restricted Download means a Digital Phonorecord Delivery in a form that cannot be retained and replayed on a permanent basis. The term Restricted Download includes an Eligible Limited Download.

Ringtone means a phonorecord of a part of a musical work distributed as a Digital Phonorecord Delivery in a format to be made resident on a telecommunications device for use to announce the reception of an incoming telephone call or other communication or message or to alert the receiver to the fact that there is a communication or message.

Service Provider means that entity governed by subparts C and D of this part, which might or might not be the Licensee, that with respect to the section 115 license.

(1) Contracts with or has a direct relationship with End Users or otherwise controls the content made available to End Users;

(2) Is able to report fully on Service Provider Revenue from the provision of musical works embodied in phonorecords to the public, and to the extent applicable, verify Service Provider Revenue through an audit; and

(3) Is able to report fully on its usage of musical works, or procure such reporting and, to the extent applicable, verify usage through an audit.

Service Provider Revenue. (1) Subject to paragraphs (2) through (5) of this definition and subject to GAAP, Service Provider Revenue shall mean, for each Offering subject to subpart C of this part:

(i) All revenue from End Users recognized by a Service Provider for the provision of the Offering;

(ii) All revenue recognized by a Service Provider by way of sponsorship and commissions as a result of the inclusion of third-party ''in-stream'' or ''in-download'' advertising as part of the Offering, *i.e.,* advertising placed immediately at the start or end of, or during the actual delivery of, a musical work, by way of Eligible Interactive Streams or Eligible Limited Downloads; and

(iii) All revenue recognized by the Service Provider, including by way of sponsorship and commissions, as a result of the placement of third-party advertising on a Relevant Page of the Service Provider or on any page that directly follows a Relevant Page leading up to and including the Eligible Limited Download or Eligible Interactive Stream of a musical work; provided that, in case more than one Offering is available to End Users from a Relevant Page, any advertising revenue shall be allocated between or among the Service Providers on the basis of the relative amounts of the page they occupy.

(2) Service Provider Revenue shall:

(i) Include revenue recognized by the Service Provider, or by any associate, Affiliate, agent, or representative of the Service Provider in lieu of its being recognized by the Service Provider; and

(ii) Include the value of any barter or other nonmonetary consideration; and

(iii) Except as expressly detailed in this part, not be subject to any other deduction or set-off other than refunds to End Users for Offerings that the End Users were unable to use because of technical faults in the Offering or other bona fide refunds or credits issued to End Users in the ordinary course of business.

(3) Service Provider Revenue shall exclude revenue derived by the Service Provider solely in connection with activities other than Offering(s), whereas advertising or sponsorship revenue derived in connection with any Offering(s) shall be treated as provided in paragraphs (1), (2) and (4) of this definition.

(4) For purposes of paragraph (1) of this definition, advertising or sponsorship revenue shall be reduced by the actual cost of obtaining that revenue, not to exceed 15%.

(5) In instances in which a Service Provider provides a Bundled Subscription Offering to End Users, the revenue from End Users deemed to be recognized by the Service Provider for the Offering for the purpose of paragraph (1) of this definition of Service Provider Revenue shall be as follows:

(i) For Bundled Subscription Offerings where both (a) each component of the Bundle is a product or service of the Service Provider (including Affiliates) and (b) the Service Provider (including Affiliates) makes the Bundle available to End Users directly, then the revenue from End Users deemed to be recognized by the Service Provider for the purpose of paragraph (1) of this definition shall be the aggregate of the retail price paid for the Bundle (*i.e.,* all components for one retail price) multiplied by a fraction where the numerator is the standalone retail price of the Subscription Offering component in the Bundle and the denominator is the sum of the standalone retail prices of each of the components in the Bundle (*e.g.,* if a Service Provider sells the Subscription Offering component on a standalone basis for $10/month and a separate product and/or service on a standalone basis for $5/month, then the fraction shall be $10 divided by $15, *i.e.,* ⅔, resulting in Service Provider Revenue of $8,000 if the aggregate of the retail price paid for the Bundle is $12,000).

(ii) For Bundled Subscription Offerings where either one or more components of the Bundle are not products or services of the Service Provider (including Affiliates) or the Service Provider (including Affiliates) does not make the Bundle available to End Users directly, then the revenue from End Users deemed to be recognized by the Service Provider for the purpose of paragraph (1) of this definition shall be the revenue recognized by the Service Provider from the Bundle multiplied by a fraction where the numerator is the standalone retail price of the Subscription Offering component in the Bundle and the denominator is the sum of the standalone retail prices of each of the components of the Bundle. Notwithstanding the preceding sentence, where the Service Provider does not recognize revenue for one or more components of the Bundle, then the standalone price(s) of the component(s) for which revenue is not recognized shall not be included in the calculation of the denominator of the fraction described in this sub-paragraph (*e.g.,* where a Bundle of three services, each with a standalone price of $20/month, sells for $50/month, and the Service Provider recognizes $30,000 of revenue from the provision of only two of those services, one of which is a Subscription Offering, then the fraction shall be $20 divided by $40, *i.e.,* ½, resulting in Service Provider Revenue of $15,000).

(iii) For the calculations in paragraphs (5)(i) and (ii) of this definition, in the event that there is no standalone published price for a component of the Bundle, then the Service Provider shall use the average standalone published price for End Users for the most closely comparable product or service in the U.S. or, if more than one comparable exists, the average of standalone prices for comparables. If no reasonably comparable product or service exists in the U.S., then the Service Provider may use another good faith, reasonable measure of the market value of the component.

Sound Recording Company means a person or entity that:

(1) Is a copyright owner of a sound recording embodying a musical work;

(2) In the case of a sound recording of a musical work fixed before February 15, 1972, has rights to the sound recording, under chapter 14 of title 17, United States Code, that are equivalent to the rights of a copyright owner of a sound recording of a musical work under title 17, United States Code;

(3) Is an exclusive Licensee of the rights to reproduce and distribute a sound recording of a musical work; or

(4) Performs the functions of marketing and authorizing the distribution of a sound recording of a musical work under its own label, under the authority of a person identified in paragraph (1) through (3).

Standalone Limited Offering means a Subscription Offering providing Eligible Interactive Streams or Eligible Limited Downloads for which—

(1) An End User cannot choose to listen to a particular sound recording (*i.e.,* the Service Provider does not provide Eligible Interactive Streams of

individual recordings that are on-demand, and Eligible Limited Downloads are rendered only as part of programs rather than as individual recordings that are on-demand); or

(2) The particular sound recordings available to the End User over a period of time are substantially limited relative to Service Providers in the marketplace providing access to a comprehensive catalog of recordings (*e.g.,* a product limited to a particular genre or permitting Eligible Interactive Streams only from a monthly playlist consisting of a limited set of recordings).

Standalone Non-Portable Subscription Offering—Streaming Only means a Subscription Offering through which an End User can listen to sound recordings only in the form of Eligible Interactive Streams and only from a non-portable device to which those Eligible Interactive Streams are originally transmitted while the device has a live network connection.

Standalone Non-Portable Subscription Offering—Mixed means a Subscription Offering through which an End User can listen to sound recordings either in the form of Eligible Interactive Streams or Eligible Limited Downloads but only from a non-portable device to which those Eligible Interactive Streams or Eligible Limited Downloads are originally transmitted.

Standalone Portable Subscription Offering means a Subscription Offering through which an End User can listen to sound recordings in the form of Eligible Interactive Streams or Eligible Limited Downloads from a portable device.

Stream means the digital transmission of a sound recording of a musical work to an End User—

(1) To allow the End User to listen to the sound recording, while maintaining a live network connection to the transmitting service, substantially at the time of transmission, except to the extent that the sound recording remains accessible for future listening from a Streaming Cache Reproduction;

(2) Using technology that is designed such that the sound recording does not remain accessible for future listening, except to the extent that the sound recording remains accessible for future listening from a Streaming Cache Reproduction; and

(3) That is subject to licensing as a public performance of the musical work.

Streaming Cache Reproduction means a reproduction of a sound recording embodying a musical work made on a computer or other receiving device by a Service Provider solely for the purpose of permitting an End User who has previously received a Stream of that sound recording to play the sound recording again from local storage on the computer or other device rather than by means of a transmission; provided that the End User is only able to do so while maintaining a live network connection to the Service Provider, and the reproduction is encrypted or otherwise protected consistent with prevailing industry standards to prevent it from being played in any other manner or on any device other than the computer or other device on which it was originally made.

Student Plan means a discounted Subscription Offering available on a limited basis to students.

Subscription Offering means an Offering for which End Users are required to pay a fee to have access to the Offering for defined subscription periods of 3 years or less (in contrast to, for example, a service where the basic charge to users is a payment per download or per play), whether the End User makes payment for access to the Offering on a standalone basis or as part of a Bundle.

TCC means the total amount expensed by a Service Provider or any of its Affiliates in accordance with GAAP for rights to make Eligible Interactive Streams or Eligible Limited Downloads of a musical work embodied in a sound recording through the Service Provider for the Accounting Period, which amount shall equal the Applicable Consideration for those rights at the time the Applicable Consideration is properly recognized as an expense under GAAP. As used in this definition, ‘‘Applicable Consideration’’ means anything of value given for the identified rights to undertake the Licensed Activity, including, without limitation, ownership equity, monetary advances, barter or any other monetary and/or nonmonetary consideration, whether that consideration is conveyed via a single agreement, multiple agreements and/or agreements that do not themselves authorize the Licensed Activity but nevertheless provide consideration for the identified rights to undertake the Licensed Activity, and including any value given to an Affiliate of a Sound Recording Company for the rights to undertake the Licensed Activity. Value given to a Copyright Owner of musical works that is controlling, controlled by, or under common control with a Sound Recording Company for rights to undertake the Licensed Activity shall not be considered value given to the Sound Recording Company. Notwithstanding the foregoing, Applicable Consideration shall not include in-kind promotional consideration given to a Sound Recording Company (or Affiliate thereof) that is used to promote the sale or paid use of sound recordings embodying musical works or the paid use of music services through which sound recordings embodying musical works are available where the in-kind promotional consideration is given in connection with a use that qualifies for licensing under 17 U.S.C. 115.

User Manipulation means any behavior that artificially distorts the number of Plays, including, but not limited to, the use of manual (*e.g.,* click farms) or automated (*e.g.,* bots) means.

§ 385.3 Late payments.

A Licensee shall pay a late fee of 1.5% per month, or the highest lawful rate, whichever is lower, for any payment owed to a Copyright Owner and remaining unpaid after the due date established in 17 U.S.C. 115(c)(2)(I) or 17 U.S.C. 115(d)(4)(A)(i), as applicable and detailed in part 210 of this title. Late fees shall accrue from the due date until the Copyright Owner receives payment.

§ 385.4 Recordkeeping for promotional or free trial non-royalty-bearing uses.

(a) *Effect of Copyright Office recordkeeping regulations.* Unless and until the Copyright Office promulgates superseding regulations concerning recordkeeping for promotional or free trial non-royalty-bearing uses subject to this part, the recordkeeping provisions in this section shall apply to Service Providers.

(b) *General.* A Service Provider transmitting a sound recording embodying a musical work subject to section 115 and subparts C and D of this part and claiming a Promotional Offering or Free Trial Offering zero royalty rate shall keep complete and accurate contemporaneous written records of making or authorizing Eligible Interactive Streams or Eligible Limited Downloads, including the sound recordings and musical works involved, the artists, the release dates of the sound recordings, a brief statement of the promotional activities authorized, the identity of the Offering or Offerings for which the zero-rate is authorized (including the internet address if applicable), and the beginning and end date of each zero rate Offering.

(c) *Retention of records.* A Service Provider claiming zero rates shall maintain the records required by this section for no less time than the Service Provider maintains records of royalty-bearing uses involving the same types of Offerings in the ordinary course of business, but in no event for fewer than five years from the conclusion of the zero rate Offerings to which they pertain.

(d) *Availability of records.* If the Mechanical Licensing Collective requests information concerning zero rate Offerings, the Service Provider shall respond to the request within an agreed, reasonable time.

■ 3. Revise subpart C to read as follows:

Subpart C—Eligible Interactive Streaming, Eligible Limited Downloads, Standalone Limited Offerings, Mixed Service Bundles, Bundled Subscription Offerings, Locker Services, and Other Delivery Configurations

§ 385.20 Scope.

This subpart establishes rates and terms of royalty payments for Eligible Interactive Streams and Eligible Limited Downloads of musical works, and other reproductions or distributions of musical works through Standalone Limited Offerings, Mixed Service Bundles, Bundled Subscription Offerings, Paid Locker Services, and Purchased Content Locker Services provided through subscription and nonsubscription digital music Service Providers in accordance with the provisions of 17 U.S.C. 115, exclusive of Offerings subject to subpart D of this part.

§ 385.21 Royalty rates and calculations.

(a) *Applicable royalty.* Licensees that engage in Licensed Activity covered by this subpart pursuant to 17 U.S.C. 115 shall pay royalties therefor that are calculated as provided in this section.

(b) *Rate calculation.* Royalty payments for Licensed Activity in this subpart shall be calculated as provided in this paragraph (b). If a Service Provider makes available different Offerings, royalties must be calculated separately with respect to each Offering taking into consideration Service Provider Revenue, TCC, subscribers, Plays, expenses, and Performance Royalties associated with each Offering. A Service Provider shall not be required to subject the same portion of Service Provider Revenue, TCC, subscribers, Plays, expenses, or Performance Royalties to the calculation of royalties for more than one Offering in an Accounting Period.

(1) *Step 1: Calculate the all-in royalty for the Offering.* For each Accounting Period, the all-in royalty for each Offering in this subpart with the exception of Mixed Service Bundles shall be the greater of:

(i) The applicable percent of Service Provider Revenue, as set forth in Table 1 to this paragraph (b)(1), and

(ii) The result of the TCC Prong Calculation for the respective type of Offering as set forth in Table 2 to this paragraph (b)(1). For Mixed Service Bundles, the all-in royalty shall be the result of the TCC Prong Calculation as set forth in Table 2.

TABLE 1 TO PARAGRAPH (b)(1)

Royalty year:	2023	2024	2025	2026	2027
Percent of Service Provider Revenue	15.1	15.2	15.25	15.3	15.35

TABLE 2 TO PARAGRAPH (b)(1)

Type of offering	TCC prong calculation
Standalone Non-Portable Subscription Offering—Streaming Only	The lesser of (i) 26.2% of TCC for the Accounting Period or (ii) the aggregate amount of 60 cents per subscriber for the Accounting Period.
Standalone Non-Portable Subscription Offering—Mixed	The lesser of (i) 26.2% of TCC for the Accounting Period or (ii) the aggregate amount of 60 cents per subscriber for the Accounting Period.
Standalone Portable Subscription Offering	The lesser of (i) 26.2% of TCC for the Accounting Period or (ii) the aggregate amount of $1.10 per subscriber for the Accounting Period.
Free nonsubscription/ad-supported services free of any charge to the End User.	26.2% of TCC for the Accounting Period.
Bundled Subscription Offering	24.5% of TCC for the Accounting Period.
Mixed Service Bundle	26.2% of TCC for the Accounting Period.
Purchased Content Locker Service	26.2% of TCC for the Accounting Period.
Standalone Limited Offering	26.2% of TCC for the Accounting Period.
Paid Locker Service	26.2% of TCC for the Accounting Period.

(2) *Step 2: Subtract applicable Performance Royalties.* From the amount determined in step 1 in paragraph (b)(1) of this section, for each Offering of the Service Provider, subtract the total amount of Performance Royalties that the Service Provider has expensed or will expense pursuant to public performance licenses in connection with uses of musical works through that Offering during the Accounting Period that constitute Licensed Activity. Although this amount may be the total of the Service Provider's payments for that Offering for the Accounting Period, it will be less than the total of the performance royalties if the Service Provider is also engaging in public performance of musical works that does not constitute Licensed Activity. In the case in which the Service Provider is also engaging in the public performance of musical works that does not constitute Licensed Activity, the amount to be subtracted for Performance Royalties shall be the amount allocable to Licensed Activity uses through the relevant Offering as determined in relation to all uses of musical works for which the Service Provider pays performance royalties for the Accounting Period. The Service Provider shall make this allocation on the basis of Plays of musical works, provided that if the Service Provider is not capable of tracking Play information, including because of bona fide limitations of the available technology for Offerings of that nature or of devices useable with the Offering, the allocation may instead be accomplished in a manner consistent with the methodology used for making royalty payment allocations for the use of individual sound recordings, and

further provided that, if the Service Provider is also not capable of utilizing a manner consistent with a methodology used for making royalty payment allocations for the use of individual sound recordings, the Service Provider may use an alternative, good faith methodology that is reasonable, identifiable, and implemented consistently.

(3) *Step 3: Determine the payable royalty pool.* The payable royalty pool is the amount payable for the reproduction and distribution of all musical works used by the Service Provider by virtue of its Licensed Activity for a particular Offering during the Accounting Period. This amount is the greater of:

(i) The result determined in step 2 in paragraph (b)(2) of this section; and

(ii) The royalty floor (if any) resulting from the calculations described in paragraph (d) of this section.

(4) *Step 4: Calculate the per-work royalty allocation.* This is the amount payable for the reproduction and distribution of each musical work used by the Service Provider by virtue of its Licensed Activity through a particular Offering during the Accounting Period. To determine this amount, the result determined in step 3 in paragraph (b)(3) of this section must be allocated to each musical work used through the Offering. The allocation shall be accomplished by the Mechanical Licensing Collective by dividing the payable royalty pool determined in step 3 for the Offering by the total number of Plays of all musical works through the Offering during the Accounting Period (other than Plays subject to subpart D of this part) to yield a per-Play allocation, and multiplying that result by the number of Plays of each musical work (other than Plays subject to subpart D of this part) through the Offering during the Accounting Period. For purposes of determining the per-work royalty allocation in all calculations under step 4 in this paragraph (b)(4) only (*i.e.,* after the payable royalty pool has been determined), for sound recordings of musical works with a playing time of over 5 minutes, each Play shall be counted as provided in paragraph (c) of this section. Notwithstanding the foregoing, if the Service Provider is not capable of tracking Play information because of bona fide limitations of the available technology for Offerings of that nature or of devices useable with the Offering, the per-work royalty allocation may instead be accomplished in a manner consistent with the methodology used for making royalty payment allocations for the use of individual sound recordings.

(c) *Overtime adjustment.* For purposes of the calculations in step 4 in paragraph (b)(4) of this section only, for sound recordings of musical works with a playing time of over 5 minutes, adjust the number of Plays as follows.

(1) 5:01 to 6:00 minutes—Each Play = 1.2 Plays.

(2) 6:01 to 7:00 minutes—Each Play = 1.4 Plays.

(3) 7:01 to 8:00 minutes—Each Play = 1.6 Plays.

(4) 8:01 to 9:00 minutes—Each Play = 1.8 Plays.

(5) 9:01 to 10:00 minutes—EachPlay = 2.0 Plays.

(6) For playing times of greater than 10 minutes, continue to add 0.2 Plays for each additional minute or fraction thereof.

(d) *Royalty floors for specific types of Offerings.* The following royalty floors for use in step 3 in paragraph (b)(3) of this section shall apply to the respective types of Offerings:

(1) *Standalone non-portable Subscription Offerings—streaming only.* Except as provided in paragraphs (d)(4) and (6) of this section with respect to Standalone Limited Offerings, in the case of a Subscription Offering through which an End User can listen to sound recordings only in the form of Eligible Interactive Streams and only from a non-portable device to which those Eligible Interactive Streams are originally transmitted while the device has a live network connection, the royalty floor for use in step 3 in paragraph (b)(3) of this section is the aggregate amount of 18 cents per subscriber per Accounting Period.

(2) *Standalone non-portable Subscription Offerings—mixed.* Except as provided in paragraphs (d)(4) and (6) of this section with respect to Standalone Limited Offerings, in the case of a Subscription Offering through which an End User can listen to sound recordings either in the form of Eligible Interactive Streams or Eligible Limited Downloads but only from a non-portable device to which those Eligible Interactive Streams or Eligible Limited Downloads are originally transmitted, the royalty floor for use in step 3 in paragraph (b)(3) of this section is the aggregate amount of 36 cents per subscriber per Accounting Period.

(3) *Standalone portable Subscription Offerings.* Except as provided in paragraphs (d)(4) and (6) of this section with respect to Standalone Limited Offerings, in the case of a Subscription Offering through which an End User can listen to sound recordings in the form of Eligible Interactive Streams or Eligible Limited Downloads from a portable device, the royalty floor for use in step 3 in paragraph (b)(3) of this section is the aggregate amount of 60 cents per subscriber per Accounting Period.

(4) *Bundled Subscription Offerings.* In the case of a Bundled Subscription Offering, the royalty floor for use in step 3 in paragraph (b)(3) of this section is the aggregate amount of 33 cents per Accounting Period for each Active Subscriber. Notwithstanding the foregoing, solely where the Licensed Activity provided as part of a Bundled Subscription Offering would qualify as a Standalone Limited Offering if offered on a standalone basis, the royalty floor for use in step 3 in paragraph (b)(3) of this section is the aggregate amount of 25 cents per Accounting Period for each Active Subscriber.

(5) *Mixed Service Bundles.* In the case of a Mixed Service Bundle, the royalty floor for use in step 3 in paragraph (b)(3) of this section is the aggregate amount of 25 cents per Accounting Period for each Active Subscriber.

(6) *Other Offerings.* A Standalone Limited Offering, a Paid Locker Service, a Purchased Content Locker Service, and a free nonsubscription/ad-supported service free of any charge to the End User shall not be subject to a royalty floor in step 3 in paragraph (b)(3) of this section.

(e) *Computation of per-subscriber rates and royalty floors.* For purposes of this section, to determine the per-subscriber rates in step 1 in paragraph (b)(1) of this section and the royalty floors in step 3 in paragraph (b)(3) of this section, as applicable to any particular Offering, the total number of subscribers for the Accounting Period shall be calculated by taking all End Users who were subscribers for a complete Accounting Period, prorating in the case of End Users who were subscribers for only part of an Accounting Period (such proration may take into account the subscriber's billing period), and deducting on a prorated basis for End Users covered by an Offering subject to subpart D of this part, except in the case of a Bundled Subscription Offering, subscribers shall be determined with respect to Active Subscribers. The product of the total number of subscribers for the Accounting Period and the specified number of cents per subscriber (or Active Subscriber, as the case may be) shall be used as the subscriber-based components of the royalty calculation for the Accounting Period. A Family Plan subscription shall be treated as 1.75 subscribers per Accounting Period, prorated in the case of a Family Plan subscription in effect for only part of an Accounting Period. A Student Plan subscription shall be treated as 0.5

subscribers per Accounting Period, prorated in the case of a Student Plan subscription in effect for only part of an Accounting Period. A Bundled Subscription Offering containing a Family Plan with one or more Active Subscriber(s) shall be treated as having 1.75 Active Subscribers. A Bundled Subscription Offering containing a Student Plan with an Active Subscriber shall be treated as having 0.5 Active Subscribers. For the purposes of calculating per-subscriber rates and royalty floors under this section, Artificial Accounts shall not be counted as subscribers, Active Subscribers, or End Users.

■ 4. Revise subpart D to read as follows:

Subpart D—Promotional Offerings, Free Trial Offerings and Certain Purchased Content Locker Services

§ 385.30 Scope.

This subpart establishes rates and terms of royalty payments for Promotional Offerings, Free Trial Offerings, and certain Purchased Content Locker Services provided by subscription and nonsubscription digital music Service Providers in accordance with the provisions of 17 U.S.C. 115.

§ 385.31 Royalty rates.

(a) *Promotional Offerings.* For Promotional Offerings of audio-only Eligible Interactive Streams and Eligible Limited Downloads of sound recordings embodying musical works that the Sound Recording Company authorizes royalty-free to the Service Provider, the royalty rate is zero.

(b) *Free Trial Offerings.* For Free Trial Offerings, the royalty rate is zero.

(c) *Certain Purchased Content Locker Services.* For every Purchased Content Locker Service for which the Service Provider receives no monetary consideration, the royalty rate is zero.

David P. Shaw,

Chief Copyright Royalty Judge.

David R. Strickler,

Copyright Royalty Judge.

Steve Ruwe,

Copyright Royalty Judge.

Approved by:

Dr. Carla D. Hayden,

Librarian of Congress.

[FR Doc. 2022–28316 Filed 12–29–22; 8:45 am]

BILLING CODE 1410–72–P

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 39

RIN 2900–AR71

Statutory Increase in Operations and Maintenance Grant Funding

AGENCY: Department of Veterans Affairs.

ACTION: Final rule.

SUMMARY: The Department of Veterans Affairs (VA) is amending its regulations that govern Federal grants to establish, expand, improve, or operate and maintain veterans' cemeteries. This final rule implements new statutory amendments to increase the maximum amount of grants to States and Tribal Organizations to operate and maintain veterans' cemeteries as authorized by section 2206 of the ''Johnny Isakson and David P. Roe, M.D. Veterans Health Care and Benefits Improvement Act of 2020'' (the Act). Effective on January 5, 2021, the maximum amount of operation and maintenance grants increased from $5 million to $10 million. This final rule implements that statutory change. Additionally, VA is revising the date by which the list of approved pre-applications is prioritized for fiscal year funding from August 15 to October 1 each year.

DATES: This rule is effective December 30, 2022.

FOR FURTHER INFORMATION CONTACT: George Eisenbach, Director of Veterans Cemetery Grants Program, National Cemetery Administration (41E), Department of Veterans Affairs, 810 Vermont Avenue NW, Washington, DC 20420. Telephone: (202) 632–7369. (This is not a toll-free telephone number.)

SUPPLEMENTARY INFORMATION: This final rule amends 38 CFR part 39 to conform with statutory amendments made by section 2206 of Public Law 116–315, the ''Johnny Isakson and David P. Roe, M.D. Veterans Health Care and Benefits Improvement Act of 2020'' (the Act). The Act amended Section 2408(f)(2) of title 38, United States Code (U.S.C.) to increase the maximum amount of grants VA could award for operating and maintaining Veterans' cemeteries from $5 million to $10 million.

To implement this authority, VA is revising regulatory text to replace ''$5 million'' with ''$10 million'' every place it appears in 39 CFR 39.3 and 39.80. Specifically, VA is revising the information for Priority Group 4 operation and maintenance grants in existing 38 CFR 39.3(c) to update the reference to the maximum grant awards to be made in any fiscal year from $5 million to $10 million. Similarly, we are revising the grant award information in § 39.80(a)(2) and (b) to clarify that operations and maintenance grants for Priority Group 4 projects must not result in a payment of more than $10 million.

In § 39.3(d), VA is replacing ''By August 15 of each year'' with ''By October 1 of each year'' to align the date for finalizing the prioritization of preapplications to the beginning of the fiscal year in which the associated final grant applications will be eligible for award. The August 15 date is not required by statute, but instead was a self-imposed deadline for finalizing the priority listing of preapplications when the grant program was first established. Since then, the number of preapplications has grown, and VA needs the additional time to conduct the final prioritization. VA publishes this date in regulation to ensure transparency and awareness of the process within the interested grant community.

Preapplications are accepted and evaluated on a rolling basis; however, only those preapplications that were received on or before July 1 of the current fiscal year are eligible for consideration in the prioritization process for the upcoming/next fiscal year. The preapplication process serves as a means to determine whether the proposed project conforms to statutory and regulatory requirements. If the preapplication is conforming, VA notifies the State or Tribal Organization that the preapplication has been found to meet the requirements, and the proposed project is included in the prioritization.

This change from August 15 to October 1 for finalizing the prioritization list expands VA's timeframe for conducting the prioritization of preapplications by approximately 45 calendar days. This does not affect a grant applicant's ability or opportunity to submit a final grant application for the fiscal year in which it is eligible for award and does not affect timeframes for awarding grants. Applicants may begin preparing final grant applications at any time and may submit the final application at any time. The October 1 date is merely the announcement of the priority of proposed projects based on preapplications and reflects the order in which those projects will be awarded and funded. Additionally, publishing this date in regulation is primarily informational for grant applicants and is not related to any subsequent deadlines that would affect applicants. VA works with grant applicants throughout the final application process to award grants based on priority and available funding in accordance with 38 CFR part 39.

Administrative Procedure Act

The Secretary of Veterans Affairs finds that there is good cause under the provisions of 5 U.S.C. 553(b)(B) to publish this rule without prior opportunity for public comment and dispense with the 30-day delay for the effective date of a rule under 5 U.S.C. 553(d)(3). Pursuant to section 553(b)(B) of the Administrative Procedure Act, general notice and opportunity for public comment are not required with respect to a rulemaking when an ''agency for good cause finds (and incorporates the finding and a brief statement of reasons therefor in the rules issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.'' Pursuant to section 553(d)(3), an agency may ''for good cause found'' dispense with the 30-day delay in the effective date of a rule. Because the increased grant amount is authorized by law and effective immediately, the Secretary finds that it is unnecessary to delay issuance of this rule for the purpose of soliciting prior public comment or to delay the rule's effective date. By statute, Congress has imposed a cap on the amount that VA expends for operation and maintenance grants, and VA regulations provide that VA will award operations and maintenance grants up to, but not exceeding, that cap. VA is not changing its policy of awarding operation and maintenance grants up to the statutory cap, but merely updating the regulation to reflect the statutory cap now in effect. *See Hadson Gas Sys.* v. *FERC,* 75 F.3d 680, 684 (D.C. Cir. 1996) (finding that the act of amending regulatory language to reflect statutory changes does not require an agency to engage in notice and comment with respect to unchanged aspects of the regulatory scheme).

Executive Orders 12866 and 13563

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, and other advantages; distributive impacts; and equity). Executive Order 13563 (Improving Regulation and Regulatory Review) emphasizes the importance of quantifying both costs and benefits, reducing costs, harmonizing rules, and promoting flexibility. The Office of Information and Regulatory Affairs has determined that this rule is not a significant regulatory action under Executive Order 12866.

The Regulatory Impact Analysis associated with this rulemaking can be found as a supporting document at *www.regulations.gov.*

Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601–612, is not applicable to this rulemaking because notice of proposed rulemaking is not required. 5 U.S.C. 601(2), 603(a), 604(a).

Unfunded Mandates

The Unfunded Mandates Reform Act of 1995 requires, at 2 U.S.C. 1532, that agencies prepare an assessment of anticipated costs and benefits before issuing any rule that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more (adjusted annually for inflation) in any one year. This final rule will have no such effect on State, local, and tribal governments, or on the private sector.

Paperwork Reduction Act

This final rule contains no provisions constituting a collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3521).

Assistance Listing

The Catalog of Federal Domestic Assistance program number and title for this final rule is 64.203, Veterans Cemetery Grants Program.

Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), the Office of Information and Regulatory Affairs designated this rule as not a major rule, as defined by 5 U.S.C. 804(2).

List of Subjects in 38 CFR Part 39

Cemeteries, Grant Programs—veterans, Veterans.

Signing Authority

Denis McDonough, Secretary of Veterans Affairs, approved this document on December 22, 2022, and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs.

Jeffrey M. Martin,

Assistant Director, Office of Regulation Policy & Management, Office of General Counsel, Department of Veterans Affairs.

For the reasons stated in the preamble, the Department of Veterans Affairs amends 38 CFR part 39 as set forth below:

PART 39—AID FOR THE ESTABLISHMENT, EXPANSION, AND IMPROVEMENT, OR OPERATION AND MAINTENANCE, OF VETERANS CEMETERIES.

■ 1. The authority citation for Part 39 continues to read as follows:

Authority: 38 U.S.C. 101, 501, 2408, 2411, 3765.

Subpart A—General Provisions

■ 2. Amend § 39.3 by revising paragraphs (c) and (d) to read as follows:

§ 39.3 Priority list.

* * * * *

(c) Grants for projects within Priority Group 4 will be awarded in any fiscal year only after grants for all project applications under Priority Groups 1, 2, and 3 that are ready for funding have been awarded. Within Priority Group 4, projects will be ranked in priority order based upon VA's determination of the relative importance of proposed improvements and the degree to which proposed Operation and Maintenance Projects achieve NCA national shrine standards of appearance. No more than $10 million in any fiscal year will be awarded for Operation and Maintenance Projects under Priority Group 4.

(d) By October 1 of each year, VA will make a list prioritizing all preapplications that were received on or before July 1 of that year and that were approved under § 39.31 or § 39.81, ranking them in their order of priority within the applicable Priority Group for funding during the fiscal year. Preapplications from previous years will be re-prioritized each year and do not need to be resubmitted.

(Authority: 38 U.S.C. 501, 2408)

■ 3. Amend § 39.80 by revising paragraphs (a)(2) and (b) to read as follows:

§ 39.80 General requirements for a grant.

(a) * * *

(2) Its project must be ranked sufficiently high within Priority Group 4 as defined in § 39.3 for the applicable fiscal year so that funds are available for the project, and a grant for the project must not result in payment of more than the $10 million total amount permissible for all Operation and Maintenance Projects in any fiscal year;

* * * * *

(b) VA may approve under § 39.85 any Operation and Maintenance Project grant application up to the amount of the grant requested once the requirements under paragraph (a) of this section have been satisfied, provided that sufficient funds are available, and that total amount of grants awarded during any fiscal year for Operation and Maintenance Projects does not exceed $10 million. In determining whether sufficient funds are available, VA shall consider the project's ranking in Priority Group 4; the total amount of funds available for cemetery grant awards in Priority Group 4 during the applicable fiscal year; and the prospects of higher-ranking projects being ready for the award of a grant before the end of the applicable fiscal year.

(Authority: 38 U.S.C. 501, 2408)

[FR Doc. 2022–28334 Filed 12–29–22; 8:45 am]

BILLING CODE 8320–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2022–0107; FRL–9426–02–R9]

Air Plan Approval; Arizona; Maricopa County; Power Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is taking final action to approve a revision to the Maricopa County Air Quality Department's (MCAQD or County) portion of the Arizona State Implementation Plan (SIP). The revision addresses Arizona's reasonably available control technology (RACT) SIP obligations for the Phoenix-Mesa ozone nonattainment area that is classified as Moderate nonattainment for the 2008 ozone national ambient air quality standards (NAAQS). We are approving a local rule that regulates emissions of oxides of nitrogen (NO_X) and particulate matter (PM) from power plants under the Clean Air Act (CAA or the Act).

DATES: This rule is effective January 30, 2023.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–R09–OAR–2022–0107. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available through *https://www.regulations.gov,* or please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section for additional availability information. If you need assistance in a language other than English or if you are a person with disabilities who needs a reasonable accommodation at no cost to you, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT: Kevin Gong, EPA Region IX, 75 Hawthorne St., San Francisco, CA 94105. By phone: (415) 972–3073 or by email at *gong.kevin@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, "we," "us" and "our" refer to the EPA.

Table of Contents

I. Proposed Action and Interim Final Determination

On February 8, 2022 (87 FR 7069), the EPA proposed to approve MCAQD Rule 322 "Power Plant Operations," as amended on June 23, 2021, and submitted by the Arizona Department of Environmental Quality (ADEQ) to the EPA on June 30, 2021.[1] The MCAQD regulates a portion of the Phoenix-Mesa ozone nonattainment area that is classified as Moderate for the 2008 8-hour ozone national ambient air quality standard (40 CFR 81.303). Maricopa County's "Analysis of Reasonably Available Control Technology For The 2008 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) State Implementation Plan (RACT SIP)," adopted December 5, 2016, submitted June 22, 2017 (the "2016 RACT SIP"), found that there were major sources of NO_X within the Maricopa County portion of the Phoenix-Mesa ozone nonattainment area subject to Rule 322. Accordingly, this rule must establish RACT levels of control for applicable major sources of NO_X.

Rule 322 regulates emissions from electricity steam generating units, cogeneration steam units, and turbines. It also includes related recordkeeping, reporting, and monitoring requirements. The version of Rule 322 that we are acting on in this rule (*i.e.,* the version adopted on June 23, 2021, and submitted to the EPA on June 30, 2021) corrects several deficiencies in a previous version of Rule 322 that was adopted by MCAQD on November 2, 2016, and submitted to the EPA on June 22, 2017, and that resulted in the EPA's disapproval published in the **Federal Register** in February 2020.[2] The EPA has determined that this revised version of Rule 322 corrects the deficiencies in the 2017 submitted version related to flawed cost effectiveness analyses and the lack of enforceable operational restrictions in the rule itself and, further, that it meets the EPA's criteria for RACT for this source category.

We proposed to approve Rule 322 because we determined that it complies with the relevant CAA requirements in CAA sections 110, 182(b)(2), 182(f), and 193. Our proposed action contains more information on Rule 322 and our evaluation of the SIP revision. On the same day, we also made an interim final determination (87 FR 7042) that the submittal from the ADEQ corrected SIP deficiencies from a previous submittal, allowing us to defer the imposition of sanctions resulting from our disapproval of a previously submitted version of Rule 322 (85 FR 43692, July 20, 2020).

II. Public Comments and EPA Responses

The EPA's proposed action provided a 30-day public comment period. During this period, we received five comments. Four of these comments were from members of the public and were generally supportive of our proposed action or were not germane. The fifth comment was submitted by Air Law for All, Ltd. on behalf of the Center for Biological Diversity and the Sierra Club (the commenter from here on referred to as "ALFA" or "the commenter").

Low Use Exemptions and RACT

ALFA asserts that Rule 322's annual operational limits cannot be used to exempt units from RACT for short-term ozone standards, that Rule 322's limits on operation are used to "artificially inflate the annualized cost-effectiveness of NO_X controls to justify not installing RACT-level technology," and that Rule 322 uses a long-term annual average to circumvent the installation of overall RACT level controls.

We do not agree with the commenter's assertions. As discussed further below,

[1] In our February 8, 2022 proposed rule, we inadvertently cited the submittal date for this submittal as June 24, 2021, which was the date that the letters from the County and State transmitting these materials were signed. The date that these materials were received in the EPA's SPeCS for SIPs system was June 30, 2021.

[2] See EPA Region IX, "Technical Support Document for Maricopa County Air Quality Department Rule 322, Power Plant Operations," January 2022; 87 FR 7070 (February 8, 2020).

and contrary to the statements in the comment letter, Rule 322 satisfies RACT requirements for NO_X emissions from power plants in two ways. First, it includes RACT-level NO_X emission limits in section 306 that apply to electric utility steam generating turbines rated greater than 100 MMBtu/hr and electric utility stationary gas turbines rated greater than 10 MMBtu/hr.[3] Second, Rule 322 provides an exemption from the RACT-level NO_X emission limit only for emissions units that meet certain criteria that are set forth in section 104.4. In particular, for units that operate at or below 10 percent annual capacity factor, Rule 322 allows an exemption from NO_X RACT limits only if the facility demonstrates through an analysis that RACT-level controls are not economically or technologically feasible. Rule 322's provisions for low use equipment are an important component of EPA's determination that Rule 322 satisfies the RACT obligation under the CAA for this source category.[4] We note that the EPA has approved rules that exempt certain units from RACT requirements based on low use in other SIPs.[5]

Section 104.4 of Rule 322 now allows for equipment that operates at or below 10 percent of the unit's calendar year annual capacity factor[6] to be exempt from NO_X and CO emissions limitations in sections 306 and 307 if the equipment meets the criteria specified in section 104.4(a), (b) and (c).[7] To qualify for the exemption from the NO_X and CO emissions limits in sections 306 and 307, section 104.4(a) requires an owner or operator to submit an analysis to the MCAQD Control Officer and EPA Administrator demonstrating that conventional commercially available control technology is not technically or economically feasible. In addition, section 104.4(b) requires an owner or operator to submit, within 60 days of MCAQD approval, an application to modify the equipment's permit to include an annual heat input limit (*i.e.,* a limit on the amount of fuel that can be used in the unit annually), and section 104.4(c) specifies that owners and operators must demonstrate compliance with the heat input limit by multiplying the higher heating value (expressed in terms of either MMBtu/ mass or MMBtu/volume by fuel use (mass or volume)).

Appendix 12 to Maricopa County's 2021 submittal includes a set of three analyses of technical feasibility and cost effectiveness (*i.e.,* economic feasibility) for thirteen emissions units at four different facilities owned by Arizona Public Service (APS) and Salt River Project (SRP).[8] APS and SRP seek to comply with Rule 322 by operating these units subject to the 10 percent annual capacity factor limit in section 104.4.[9] The analyses present available NO_X control technologies, including water injection, steam injection, low NO_X burners, dry low NO_X combustion, selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR).[10] The analyses next determine which available technologies are technically feasible for the various emissions units. The analyses then assess the cost effectiveness of the technically feasible options by considering the capital and annual costs compared to the NO_X reductions that would be expected to result from the controls. For this last step, each analysis assumed that the emissions unit would operate at 10 percent of its rated capacity.

It is important to note that the analyses state, for each emissions unit analyzed, actual operation of each unit was far below ten percent of capacity. For example, Table 3–2 of the analysis for APS Ocotillo and West Phoenix power plants presents the capacity factor for each of the four units analyzed in the document in the years 2015, 2016 and 2017, the most recent three years at the time the analysis was developed; of the twelve data points, only two units were operated above 1 percent annual capacity, and eight were below 0.5 percent annual capacity.[11] Similarly, the analysis for SRP Agua Fria generating station's units 1–3 states that the units ''have a very low utilization, with a typical capacity factor of approximately 5 percent,''[12] and the analysis for SRP Agua Fria units 4–6 states that the annual capacity factor is less than 1 percent.[13] Moreover, the analysis for SRP Kyrene units 4–6 states that the units have ''very low utilization, with a typical capacity factor less than 0.1 percent.''[14]

The fact that actual usage of the emissions units that will be regulated

[3] We note that the limits in the submitted rule are more stringent than the NO_X emission limits that are currently in the SIP. (The current SIP-approved rule was adopted by MCAQD in 2007 and approved by the EPA in 2009. 74 FR 52693 (October 14, 2009).) For example, the current SIP-approved version of Rule 322 does not contain any NO_X limit for electric utility stationary gas turbines, whereas the submitted version of Rule 322 establishes a NO_X limit of 42 ppm for these units, if they are fired by gaseous fossil fuel, and 65 ppm if they are fired by liquid fossil fuel. This notice provides additional discussion comparing the submitted and currently SIP-approved versions of Rule 322 below.

[4] In the 1992 General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990, EPA stated that ''it is possible that a state could demonstrate that an existing source in an area should not be subject to a control technology especially where such control is unreasonable in light of the area's attainment needs or infeasible.'' 57 FR 13498, 13541, note 20 (April 16, 1992). Appendix C4 to the General Preamble for the Implementation of Title I of the CAA Amendments of 1990 (titled ''RACT Determinations for Stationary Sources'') further elaborates on this point, clarifying that ''States may give substantial weight to cost effectiveness in evaluating the economic feasibility of an emission reduction technology.'' 82 FR 18070, 18074 (Apr. 28, 1992). Appendix C4 refers to the General Preamble discussion on particulate matter, but its discussion on economic feasibility also applies to considerations for NO_X RACT emissions controls. That is what the State has done in this instance; when the facilities operate at or below 10 percent annual capacity factor, there is no requirement to install RACT because it is not cost effective.

[5] See, for example: Colorado's 5 CCR 1001–9, Regulation 7, part E, section II.A.2.a, approved at 86 FR 11125 (February 24, 2021); Massachusetts 310 CMR 7.19, section (1)(d), approved at 85 FR 65236 (October 15, 2020); Ventura County Air Pollution Control District Rule 74.15.1 section C.2 as low a heat input exemption approved at 81 FR 50348 (August 1, 2016); Wisconsin's NR 428.21, section (1)(d) paragraph 2 and section (2)(d) paragraph 2, approved at 75 FR 64155 (October 19, 2010); Sacramento Metropolitan Air Quality Management District Rule 411, section 113, approved at 74 FR 20880 (May 6, 2009).

[6] The U.S. Energy Information Administration defines ''capacity factor'' as: ''The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.'' Available: *https://www.eia.gov/tools/glossary/index.php.*

[7] Equipment that operates at less than 10 percent of its annual capacity is also subject to provisions in Rule 322 that require compliance with good combustion practices, particulate limits, and requirements for recordkeeping and reporting. See *e.g.,* Rule 322, sections 301, 302, 303, 304 and 500. A more complete description of these provisions is included later in this notice.

[8] 2021 Submittal, Appendix 12.

[9] Besides the thirteen emissions units that seek to comply with Rule 322 by operating subject to the 10 percent annual capacity factor limit in section 104.4, there are 40 units that must comply with the emissions limits in sections 306 and 307. Of the nine facilities subject to Rule 322, four operate units seeking the low use exemption from sections 306 and 307 of the rule.

[10] The range of NO_X control technologies evaluated varied according to the specifics of the emissions units. For more detailed information, see our 2022 TSD, 9–11; 2021 Submittal at 64–189.

[11] 2021 Submittal at 71 (''Reasonably Available Control Technology (RACT) Analysis for the control of nitrogen oxides (NO_X) emission from the Arizona Public Service Ocotillo and West Phoenix Power Plants'' (October 2018) at 8).

[12] 2021 Submittal at 106 (''Reasonably Available Control Technology (RACT) Analysis for the control of nitrogen oxides (NO_X) emissions from the Salt River Project Agua Fria Generating Station'' (July 2020) at 14).

[13] 2021 Submittal at 167 (''Reasonably Available Control Technology (RACT) Analysis for the control of nitrogen oxides (NO_X) emissions from simple-cycle combustion turbine generators at the Salt River Project Agua Fria and Kyrene Generating Stations'' (July 2020) at 15).

[14] 2021 Submittal at 176, 182; (''Reasonably Available Control Technology (RACT) Analysis for the control of nitrogen oxides (NO_X) emissions from simple-cycle combustion turbine generators at the Salt River Project Agua Fria and Kyrene Generating Stations'' (July 2020) at 24, 30.)

pursuant to the low use exemption has historically been well below the 10 percent capacity factor imposed by the exemption contradicts the commenter's point that ''the limits on operation are used to artificially inflate the annualized cost-effectiveness of NO_X controls to justify not installing RACT-level technology.'' Arguably, because the cost effectiveness analyses conservatively assumed higher levels of operation than actually occur, the analyses overestimated NO_X emissions and therefore overestimated NO_X reductions that would result from use of NO_X control equipment. Because cost effectiveness is expressed as dollars (capital and operational costs of controls) per ton of emissions (emissions reductions resulting from the controls), an overestimation of emissions reductions would effectively make controls appear more cost effective, not less.

The commenter also points to a 1984 guidance document [15] to assert that ''the averaging time for ozone plan emission limitations should match the standards, that is, should be short term.'' We note, however, that section 104.4's 10 percent heat input limit differs from the emission limits addressed in the 1984 guidance in that it is also a criterion that must be met to qualify for and maintain an exemption from Rule 322's NO_X and CO limits. Further, to qualify for the exemption, section 104.4 also requires sources to submit, for Control Officer and EPA approval, a RACT analysis that demonstrates that ''conventional commercially-available control technology is not technologically and/or economically feasible.'' EPA has long considered what is technologically and economically feasible in determining RACT controls.[16] And, as explained above, the analyses in Appendix 12 of the 2021 submittal package demonstrate that the installation of RACT control technologies for units operating at 10 percent of their annual capacity factors exceeds established cost effectiveness values.

Contrary to the commenter's assertion, section 104.4's annual capacity limit does not allow sources to ''circumvent the installation of RACT level controls.'' Rather, as evidenced by the analyses in Appendix 12 of the 2021 submittal package, sources regulated by Rule 322 appear to understand section 104.4 to require not only a standard approach to evaluating the cost effectiveness of pollution controls, but also application of this approach to all emissions units, even those that are used at one percent (or even lower) of their rated capacity.[17]

It is also important to note that units regulated by the low use provisions in section 104.4 must comply with requirements in section 500, ''Monitoring and Records,'' including section 501.1 that requires owners and operators to maintain records of days and hours of operation and monthly fuel usage that will ensure that regulators, members of the public, and facility owners and operators can determine compliance with section 104.4's fuel input cap. In addition, the units regulated by the low use provisions in section 104.4 must still comply with other provisions in Rule 322, such as particulate matter emissions limitations (section 301), good combustion practice obligations for turbines (section 302), opacity limits (section 304), and fuel sulfur limits (section 305).

We acknowledge the commenter's point that the equipment for which power generators are seeking an exemption from NO_X and CO limits pursuant to section 104.4 are likely operated as peaking units and are therefore expected to operate primarily during hot summer days when ozone formation is typically high. The Clean Air Act provides states with primary responsibility for developing pollution control strategies discretion to attain the NAAQS. The states also have ''broad authority to determine the methods and particular control strategies they will use to achieve the statutory requirements.'' [18] Because we find that Rule 322 is consistent with federal standards for RACT, we believe it is appropriate for the State to use its discretion to allow these units to operate, even during high ozone periods, as long as the State can demonstrate attainment with applicable ozone NAAQS. The EPA has approved the State's attainment demonstration and the associated reasonably available control measures (RACM) demonstration for the Phoenix 2008 ozone nonattainment area,[19] and has determined that this area attained the 2008 ozone NAAQS by the applicable attainment date.[20] The U.S. Court of Appeals for the Ninth Circuit has upheld both of these actions.[21] With respect to the 2015 ozone NAAQS, which is more stringent than the 2008 ozone NAAQS, the EPA has recently determined that the Phoenix-Mesa nonattainment area failed to attain the standard by the attainment date for areas classified as Marginal and therefore it has been reclassified to the next highest classification, Moderate.[22] This ''bump up'' action means that the State of Arizona and MCAQD are subject to CAA section 182(b)(2)'s requirement to demonstrate RACT and to section 182(b)(1)'s requirement to submit a plan demonstrating reasonable further progress towards attainment for the 2015 ozone NAAQS and providing for attainment by the Moderate area attainment date.

Discretionary Authority in SIP Actions

ALFA asserts that the EPA's statement that we do not have the ''discretionary authority to address disproportionate human health or environmental effects with practical, appropriate and legally permissible methods under Executive Order 12898'' is incorrect, and that the EPA has the discretion to interpret the requirements of the Act with regard to SIP submissions, demonstrated by our application of Agency guidance in interpreting requirements for averaging times in emission limitations. The commenter further asserts that the EPA does in fact have the discretionary authority to address impacts to environmental justice communities in this context.

While the EPA may in certain circumstances have discretion to

[15] See ''Averaging Times for Compliance with VOC Emission Limits—SIP Revision Policy,'' (also referred to as the ''O'Connor Memorandum''). 51 FR 43857 (December 4, 1986). It is conceivable that this guidance pertains to limits on direct emissions of air pollutants only, not operational standards. We note that the 1990 Clean Air Act Amendments added the phrase ''work practice or operational standard'' to the definition of the terms ''emission limit'' and ''emission standard'' at CAA section 302(k).

[16] Since the 1970s, EPA has consistently defined ''RACT'' as the lowest emission limit that a particular source is capable of meeting by the application of the control technology that is reasonably available considering technological and economic feasibility. See December 9, 1976 memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management, to Regional Administrators, ''Guidance for Determining Acceptability of SIP Regulations in Non-Attainment Areas.'' 44 FR 53762 (September 17, 1979).

[17] We note further that Rule 322 does not allow ''circumvention'' of RACT by units that do not seek to qualify as exempt pursuant to section 104.4. Rule 322 applies to electric utility steam generating units and cogeneration steam generating units with rated heat input capacity greater than or equal to 100 million Btu/hour. Rule 322 clearly requires any unit that does not submit to section 104.4's limit on heat input to comply with the NO_X and CO limits in sections 306 and 307, which EPA has determined to be RACT.

[18] *BCCA Appeal Grp.* v. *EPA,* 355 F.3d 817, 822 (5th Cir. 2003) (as amended on denial of rehearing and rehearing en banc Jan. 8, 2004) (citing *Union Elec. Co.* v. *EPA,* 427 U.S. 246, 266 (1976) (''So long as the national standards are met, the state may select whatever mix of control devices it desires.'')

[19] 85 FR 33571 (June 2, 2020).

[20] 84 FR 60920 (November 12, 2019).

[21] *Bahr* v. *Regan,* 6 F.4th 1059 (9th Cir. 2021) *Matusow* v. *Wheeler,* Case No. 20–72279 (9th Cir. Apr. 21, 2022).

[22] 87 FR 60897 (October 7, 2022).

consider environmental justice in implementing the requirements of the Act, E.O. 12898 does not provide any independent authority for action. For the reasons described in our proposal, our Technical Support Document (TSD), and this notice, we have determined that the submittal satisfies the obligation to implement RACT under sections 110 and 182 of the Act. Under the CAA, the EPA is required to approve a SIP submission that meets the minimum requirements of the CAA and applicable federal regulations. Moreover, we note that while we are approving Rule 322 as meeting RACT under the requirements of the 2008 ozone NAAQS, we are not making any determinations as to whether this submittal meets requirements applicable to the Phoenix-Mesa nonattainment area for the 2015 ozone NAAQS.

Although Executive Order 12898 does not provide us with an independent basis to disapprove the County's SIP submission, we conducted an environmental justice analysis to provide additional context and information about this rulemaking to the public. To identify environmental burdens and susceptible populations in underserved communities in the areas surrounding units operating under the low use exemption in Rule 322, we performed a screening analysis using the EPA's environmental justice screening and mapping tool (''EJSCREEN'') and the Power Plants and Neighboring Communities mapping tool (''PPNC'') that includes EJSCREEN data in addition to facility emissions data collected by the EPA.[23] [24] We used these tools to assess the areas within a three-mile radius of the four facilities operating under the low use provisions of Rule 322. We selected a three-mile buffer because these facilities on their own have fairly large geographic footprints, and a three-mile radius was appropriate to capture potentially impacted communities that may be located nearby. We focused our analysis of the area on the two demographic indicators explicitly named in Executive Order 12898, the area's percentage of people of color and the percentage of low-income population.[25] Based on our screening analysis, we found that two of the four areas had higher percentages for the People of Color indicator living in the buffer zone than the state average of 45 percent (the area around the Agua Fria Generating Station reported 60 percent and the area around the West Phoenix Power Plant reported 91 percent), and three of the four areas had higher percentages for the Low Income indicator than the state average of 35 percent (Agua Fria Generating Station reported 44 percent, Ocotillo Power Plant reported 49 percent, and West Phoenix Power Plant reported 77 percent). Selected metrics from that analysis are presented below in Table 1.

TABLE 1—SELECTED ENVIRONMENTAL JUSTICE DEMOGRAPHIC INDICATORS

	Agua Fria generating station	Kyrene generating station	Ocotillo power plant	West Phoenix power plant
Estimated population in 3-mile buffer zone[26]	154,817	130,571	145,867	107,697
People of Color (AZ average 45%)	60%	43%	46%	91%
Low Income (AZ average 35%)	44%	26%	49%	77%

As discussed in the EPA's ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' people of color and low-income populations often experience greater exposure and disease burdens than the general population, which can increase their susceptibility to adverse health effects from environmental stressors.[27] Underserved communities can also experience reduced access to health care, nutritional, and fitness resources, further increasing their susceptibility. We also note that the Phoenix-Mesa area is currently designated as non-attainment for the 2008 and 2015 ozone standards.[28] Areas in nonattainment typically face other air pollution and environmental health challenges, which may especially impact these underserved communities. Such impacts are seen in the EJSCREEN data for these areas, including indexes for fine particulate matter exposure, diesel particulate matter, air toxics risks, underground storage tank, Superfund site and hazardous waste facility proximity, all being higher than the State's average. Because the APS West Phoenix Power Plant and the SRP Agua Fria Generating Station are both located near communities, which the EJSCREEN data shows is higher than the state's average for EJ demographic indicators that may indicate the presence of underserved communities, it is possible that these facilities contribute to disproportionate pollution impacts.

Even though some of the facilities that are operating units under Rule 322's partial exemption for low use units are located in or near underserved communities, approval of this rule into the SIP strengthens the Arizona SIP by incorporating more stringent requirements for power plants operating in Maricopa County into the SIP, making them enforceable by the EPA and the public. For example, the version of Rule 322 we are approving into the SIP contains more stringent NO_X limits for more emissions units compared to the version of Rule 322 currently in the SIP, which EPA approved in 2009. The

[23] U.S. Environmental Protection Agency. ''EJScreen (Version 2.0), 2022.'' Environmental Justice index and Socioeconomic Indicator tables, and EJSCREEN American Community Survey (ACS) Summary reports 2015–2019 data. Retrieved August 12, 2022 from *https://www.epa.gov/ejscreen.*

[24] U.S. Environmental Protection Agency. 2022. ''Power Plants and Neighboring Communities (PPNC), 2020'' Washington, DC: Office of Atmospheric Programs, Clean Air Markets Division. Available from EPA's PPNC website: *https://www.epa.gov/airmarkets/power-plants-and-neighboring-communities.* The reports generated for this analysis are available in the rulemaking docket.

[25] Executive Order 12898 focuses explicitly on these two demographic indicators, which it refers to as ''minority populations'' and ''low-income populations.'' EJSCREEN reports environmental indicators (*e.g.,* air toxics cancer risk, lead paint exposure, and traffic proximity and volume) and demographic indicators (*e.g.,* people of color, low income, and linguistically isolated populations). Depending on the indicator, a community that scores highly for an indicator may have a higher percentage of its population within a demographic group or a higher average exposure or proximity to an environmental health hazard compared to the state, region, or national average. EJSCREEN also reports EJ indexes, which are combinations of a single environmental indicator with the EJSCREEN Demographic Index. For additional information about environmental and demographic indicators and EJ indexes reported by EJSCREEN, see EPA, ''EJSCREEN Environmental Justice Mapping and Screening Tool—EJSCREEN Technical Documentation,'' section 2, September 2019.

[26] Estimates from EJSCREEN, 2015–2019 American Community Survey, U.S. Census.

[27] U.S. EPA, ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' section 4, June 2016.

[28] The EPA determined that the Phoenix-Mesa attained the 2008 ozone NAAQS by the Moderate area attainment date of July 20, 2018. 84 FR 60920 (November 12, 2019). This determination is not a redesignation to attainment and therefore it does not relieve the State from its obligations to implement RACT for this standard.

2007 version of Rule 322 does not impose NO_X limits for stationary gas turbines at all, whereas the submitted version of Rule 322 limits NO_X emissions to 42 ppm and 65 ppm when burning gaseous and liquid fossil fuels, respectively.[29] Moreover, the 2007 version of Rule 322 only limits NO_X for steam generating units for which construction commenced between May 30, 1972, and May 10, 1996; as a result, the 2007 version of Rule 322 does not regulate at least some of the units covered by the low use exemption in the 2021 version of Rule 322.[30] The 2021 version of the rule now requires all units, regardless of construction date or type, to comply with the RACT limits or demonstrate compliance with the low use provisions by limiting annual operations. Also, the units operating under the submitted version of Rule 322's partial exemption for low use units must still comply with the updated operating requirements controlling sulfur, particulate matter, and opacity, even if they are exempt from the RACT NO_X and CO limits. Therefore, we expect that this action and the codification of Rule 322's more stringent requirements into the federally enforceable SIP will contribute to reduced environmental and health impacts on all populations in Maricopa County, including people of color and low-income populations in Maricopa County. For these reasons, this action is not expected to have a disproportionately high or adverse human health or environmental effect on a particular group of people.

The EPA remains committed to working with the State of Arizona and Maricopa County to ensure that the ozone attainment requirements for this area satisfy applicable CAA requirements and thereby protect all populations in the area, including minority, low income, and indigenous populations, from disproportionately high or adverse air pollution impacts.

[29] The submitted rule also expands the applicability of CO limits to each electric utility or cogeneration steam generating unit with a rated heat input capacity greater than or equal to 100 MMBtu per hour, and to each electric utility stationary gas turbine with a rated heat input capacity at peak load greater than or equal to 10 MMBtu per hour. The 2007 version of Rule 322 limited CO emissions to the same equipment, but only if construction commenced prior to May 10, 1996.

[30] Per the RACT analyses submitted with the 2021 version of Rule 322, the APS Ocotillo and West Phoenix low use units were constructed at some point in 1972 and at least three of the SRP Agua Fria low use units were constructed well before 1972.

III. EPA Action

No comments were submitted that change our assessment of the rule as described in our proposed action. Therefore, as authorized in section 110(k)(3) of the Act, the EPA is fully approving Rule 322 into the Arizona SIP and, pursuant to the requirements in section 104.4 of Rule 322, also approving the RACT cost effectiveness demonstrations in Appendix 12 of the State's submittal for the facilities seeking to operate under the low use partial exemption. The June 23, 2021 version of Rule 322 will replace the October 17, 2007 version of this rule in the SIP. As a result of this action, the sanctions that were deferred in our interim final determination are now rescinded, and a federal implementation plan to resolve the deficiency is no longer required under section 110(c) of the Act. We will also delete our previous disapproval codified at 40 CFR 52.133 (Rules and regulations) since a subsequent version of Rule 322 is being approved.

Relatedly, we are also making a correction in 40 CFR 52.124. In our final rule of August 23, 2021 (86 FR 46986), approving revisions to the Pinal County Air Quality District's RACT demonstrations for the 2008 8-hour ozone NAAQS, we should have deleted only the codified language noting our previous disapproval of portions of Pinal County's demonstration. However, we instead inadvertently deleted all the codified disapprovals for RACT demonstrations in Arizona. This action will correct that error and revise 40 CFR 52.124 to recodify the disapprovals for Maricopa County's RACT demonstration. This is relevant to our action here because the previous disapproval for Rule 322 was a contributing factor to our overall disapproval on Maricopa County's demonstration for implementing RACT at major sources of NO_X. This language should remain in 40 CFR 52.124 until a future action addresses the remaining deficiencies that prevent us from fully approving Maricopa County's demonstration of this requirement.

The EPA has determined that this correction falls under the "good cause" exemption in section 553(b)(3)(B) of the Administrative Procedure Act (APA) which, upon finding "good cause," authorizes agencies to dispense with public participation where public notice and comment procedures are impracticable, unnecessary, or contrary to the public interest. Public notice and comment for this action is unnecessary because the underlying rule for which this correcting amendment has been prepared was already subject to a 30-day comment period, and this action merely adds amendatory instructions that reverts the errors made in the underlying rule. Further, this action is consistent with the purpose and rationale of the final rule, which is corrected herein. Because this action does not change the EPA's analyses or overall actions, no purpose would be served by additional public notice and comment. Consequently, additional public notice and comment are unnecessary.

IV. Incorporation by Reference

In this rule, the EPA is finalizing regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is finalizing the incorporation by reference of Maricopa County Rule 322 as described in Section I of this preamble and as set forth below in the amendments to 40 CFR part 52. Therefore, these materials have been approved by the EPA for inclusion in the SIP, have been incorporated by reference by the EPA into that plan, are fully federally enforceable under sections 110 and 113 of the CAA as of the effective date of the final rulemaking of the EPA's approval, and will be incorporated by reference in the next update to the SIP compilation.[31] The EPA has made, and will continue to make, these documents available through *www.regulations.gov* and at the EPA Region IX Office (please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information).

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the minimum criteria of the Act. Accordingly, this action approves a County rule as meeting federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Does not impose an information collection burden under the provisions

[31] 62 FR 27968 (May 22, 1997).

of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);

- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001); and
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the Clean Air Act.

The state did not evaluate environmental justice considerations as part of its SIP submittal. The EPA performed an environmental justice analysis for the purpose of providing additional context and information about this rulemaking to the public, not as a basis of the final action. Due to the nature of the action being taken here, this action is expected to have a neutral to positive impact on the air quality of the affected area. Thus, there is no information in the record inconsistent with the stated goals of Executive Order 12898 (59 FR 7629, February 16, 1994) of achieving environmental justice for people of color, low-income populations, and indigenous peoples.

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by February 28, 2023. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: December 21, 2022.

Martha Guzman Aceves,

Regional Administrator, Region IX.

Part 52, Chapter I, Title 40 of the Code of Federal Regulations is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for Part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart D—Arizona

■ 2. In § 52.120, in paragraph (c), amend Table 4 by revising the entry for ''Rule 322,'' and in paragraph (e), amend Table 1 by adding an entry for ''Revision of Rule 322 of the Maricopa County Air Pollution Control Regulations, Appendix 12: RACT Analyses Submitted to the Maricopa County Air Quality Department from the Arizona Public Service and the Salt River Project, only'' after the entry for ''Reasonably Available Control Technology (RACT) Analysis, Negative Declaration and Rules Adoption'' to read as follows:

§ 52.120 Identification of plan.

* * * * *

(c) * * *

TABLE 4 TO PARAGRAPH (c)—EPA-APPROVED MARICOPA COUNTY AIR POLLUTION CONTROL REGULATIONS

County citation	Title/subject	State effective date	EPA approval date	Additional explanation
*	*	*	*	*
Rule 322	Power Plant Operations.	June 23, 2021	[INSERT Federal Register CITATION], December 30, 2022.	Submitted on June 30, 2021 under an attached letter dated June 24, 2021.
*	*	*	*	*

* * * * *

(e) * * *

TABLE 1—EPA-APPROVED NON-REGULATORY AND QUASI-REGULATORY MEASURES

Name of SIP provision	Applicable geographic or nonattainment area or title/subject	State submittal date	EPA approval date	Explanation
* * * * * * *				
Revision of Rule 322 of the Maricopa County Air Pollution Control Regulations, Appendix 12: RACT Analyses Submitted to the Maricopa County Air Quality Department from the Arizona Public Service and the Salt River Project, only.	Maricopa County portion of Phoenix-Mesa nonattainment area for 2008 8-hour ozone NAAQS. Demonstrations for Equipment Under Rule 322, section 104.4, paragraph b.	June 30, 2021.	[INSERT Federal Register CITATION], December 30, 2022..	Submitted on June 30, 2021 under a letter dated June 24, 2021, as a part of the SIP revision for Maricopa County Rule 322. Required demonstrations from facilities that operate equipment seeking partial exemption from the rule through compliance with annual heat input limits.
* * * * * * *				

* * * * *

■ 3. Amend § 52.124 by adding paragraph (b) to read as follows.

§ 52.124 Part D disapproval.

* * * * *

(b) The following Reasonably Available Control Technology (RACT) determinations are disapproved because they do not meet the requirements of Part D of the Clean Air Act.

(1) [Reserved]

(2) *Maricopa County Air Quality Department.* (i) RACT determinations for major sources of NO_X, and CTG source categories for Aerospace Coating and Industrial Adhesives (''National Emission Standards for Hazardous Air Pollutants for Source Categories: Aerospace Manufacturing and Rework'' (59 FR 29216), ''Control of Volatile Organic Compound Emissions from Coating Operations at Aerospace Manufacturing and Rework Operations'' (EPA–453/R–97–004), and ''Control Techniques Guidelines for Miscellaneous Industrial Adhesives'' (EPA–453/R–08–005)), in the submittal titled ''Analysis of Reasonably Available Control Technology for the 2008 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) State Implementation Plan (RACT SIP),'' dated December 5, 2016, as adopted on May 24, 2017 and submitted on June 22, 2017.

(ii) [Reserved]

* * * * *

§ 52.133 [Amended]

■ 4. Amend § 52.133 by removing and reserving paragraph (h).

[FR Doc. 2022–28272 Filed 12–29–22; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Parts 400, 406, 407, 408, 410, 423, 431, and 435

[CMS–4199–CN]

RIN 0938–AU85

Medicare Program; Implementing Certain Provisions of the Consolidated Appropriations Act, 2021 and Other Revisions to Medicare Enrollment and Eligibility Rules; Correction

AGENCY: Centers for Medicare & Medicaid Services (CMS), Department of Health and Human Services (HHS).

ACTION: Final rule; correction.

SUMMARY: This document corrects technical and typographical errors that appeared in the final rule published in the **Federal Register** on November 3, 2022, entitled ''Medicare Program; Implementing Certain Provisions of the Consolidated Appropriations Act, 2021 and other Revisions to Medicare Enrollment and Eligibility Rules.''

DATES: *Effective date:* This correcting document is effective on December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Kristy Nishimoto, (206) 615–2367.

SUPPLEMENTARY INFORMATION:

I. Background

In FR Doc. 2022–23407 of November 3, 2022 (87 FR 66454), there were a several technical and typographical errors that are identified and corrected in this correcting document.

II. Summary of Errors

A. Summary of Errors in the Preamble

On page 66457, in a table that provides an example of the current entitlement dates compared to the revisions made by the Consolidated Appropriations Act, 2021 (CAA) there were inadvertent typographical errors in the formatting of a row of table.

On page 66468, in our discussion of the special enrollment period (SEP) to coordinate with termination of Medicaid coverage, we made typographical errors in referencing a regulatory citation.

On page 66496, in our discussion of the information collection requirements regarding beneficiary enrollment simplification, we inadvertently omitted a word.

B. Summary of Errors in the Regulations Text

On page 66506, in the amendatory instructions for § 407.25 we made a technical error in the instruction regarding paragraph (b)(3).

III. Waiver of Proposed Rulemaking

We ordinarily publish a notice of proposed rulemaking in the **Federal Register** and invite public comment on the proposed rule in accordance with 5 U.S.C. 553(b) of the Administrative Procedure Act (APA). The notice of proposed rulemaking includes a reference to the legal authority under which the rule is proposed, and the terms and substances of the proposed rule or a description of the subjects and issues involved. This procedure can be waived, however, if an agency finds good cause that a notice-and-comment procedure is impracticable, unnecessary, or contrary to the public interest and incorporates a statement of the finding and its reasons in the rule issued.

We believe that this final rule correcting document does not constitute a rule that would be subject to the notice and comment or delayed effective date requirements. This document merely corrects minor typographical errors in the final rule, but it does not make substantive changes to the policies or the implementing regulations that were adopted in the final rule. As a result, this final rule correcting document is intended to ensure that the information in the final rule accurately reflects the policies and regulatory amendments adopted in that document.

In addition, even if this were a rule to which the notice and comment procedures and delayed effective date requirements applied, we find that there is good cause to waive such requirements. Undertaking further notice and comment procedures to incorporate the minor corrections in this document into the final rule or delaying the effective date would be unnecessary, as we are not altering our policies or regulatory changes, but rather, we are simply implementing correctly the policies and regulatory changes that we previously proposed, requested comment on, and subsequently finalized. This final rule correcting document is intended solely to ensure that the final rule accurately reflects these policies and regulatory changes. Furthermore, such notice and comment procedures would be contrary to the public interest because it is in the public's interest to ensure that the final rule accurately reflects our policies and regulatory changes. Therefore, we believe we have good cause to waive the notice and comment and effective date requirements.

IV. Correction of Errors

In FR Doc. 2022–23407 of November 3, 2022 (87 FR 66454), make the following corrections:

1. On page 66457, upper one-third of the page, the untitled table, the table is corrected to read as follows:

Enrolls:	Prior to 1/1/23—entitlement begins on:	On or after 1/1/23—entitlement begins on:
In IEP		
January	April 1 (month eligibility requirements first met)	April 1 (month eligibility requirements first met).
February	April 1	April 1.
March	April 1	April 1.
April	May 1 (month following month of enrollment)	May 1.
May	July 1 (second month after month of enrollment)	June 1.
June	September 1 (third month after month of enrollment)	July 1.
July	October 1 (third month after month of enrollment)	August 1.
In GEP		
January	July 1	February.
February	July 1	March.
March	July 1	April.

2. On page 66468 in the first column, second full paragraph, last line, the regulatory citation ''407.27(f)'' is corrected to read ''407.23(f)''.

3. On page 66468 in the third column, second full paragraph, line 11, the regulatory citation, ''407.27(f)'' is corrected to read ''407.23(f)''.

4. On page 66496, first column, second full paragraph, line 4, the phrase, ''Exceptional Conditions'' is corrected to read ''Other Exceptional Conditions''.

■ 5. On page 66506, third column, amendatory instruction 16 (§ 407.25), is corrected to read, ''16. Effective January 1, 2023, § 407.25 is amended by revising paragraphs (a) and (b)(1) and adding paragraph (b)(3) to read as follows:''

Elizabeth J. Gramling,

Executive Secretary to the Department, Department of Health and Human Services.

[FR Doc. 2022–28359 Filed 12–29–22; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Parts 413 and 512

[CMS–1768–CN]

RIN 0938–AU79

Medicare Program; End-Stage Renal Disease Prospective Payment System, Payment for Renal Dialysis Services Furnished to Individuals With Acute Kidney Injury, End-Stage Renal Disease Quality Incentive Program, and End-Stage Renal Disease Treatment Choices Model; Correction

AGENCY: Centers for Medicare & Medicaid Services (CMS), HHS.

ACTION: Final rule; correction.

SUMMARY: This document corrects technical errors that appeared in the November 7, 2022 **Federal Register** in the final rule entitled ''Medicare Program; End-Stage Renal Disease Prospective Payment System, Payment for Renal Dialysis Services Furnished to Individuals With Acute Kidney Injury, End-Stage Renal Disease Quality Incentive Program, and End-Stage Renal Disease Treatment Choices Model'' (referred to hereafter as the calendar year (CY) 2023 ESRD PPS final rule).

DATES: This correction is effective January 1, 2023.

FOR FURTHER INFORMATION CONTACT:

ESRDPayment@cms.hhs.gov, for issues related to the ESRD PPS and coverage and payment for renal dialysis services furnished to individuals with acute kidney injury (AKI).

ESRDApplications@cms.hhs.gov, for issues related to applications for the Transitional Add-On Payment Adjustment for New and Innovative Equipment and Supplies (TPNIES) or the Transitional Drug Add-on Payment Adjustment (TDAPA).

SUPPLEMENTARY INFORMATION:

I. Background

In FR Doc. 2022–23778 of November 7, 2022 (87 FR 67136), there were a number of typographical errors that are identified and corrected in this correcting document. The provisions in this correction document are effective as if they had been included in the document that appeared in the November 7, 2022 **Federal Register**. Accordingly, the corrections are effective January 1, 2023.

II. Summary of Errors

On pages 67170 and 67171, we inadvertently made a typographical error to a website address. Therefore, we are correcting the website address from ''*https://www.cms.gov/Medicare/Medicare-Feefor-Service-Payment/ESRDpayment/Educational_Resources*'' to ''*https://www.cms.gov/Medicare/Medicare-Fee-for-Service-Payment/ESRDpayment/Educational_Resources.*''

On page 67194, in the first column, we inadvertently made a typographical error by including an incorrect symbol (ל) to the phrase ''100 cells/לL or >0.1 × 10/L.'' In addition, the font size of this phrase inadvertently appears larger than the standard **Federal Register** text. Therefore, we are correcting these errors by replacing the phrase ''100 cells/לL or >0.1 × 10/L'' to ''>100 cells/µL or >0.1 × 10/L''.

On page 67195, in the third column, we inadvertently made a typographical error by including an incorrect symbol (ל) to the phrase ''(>100 cells/לL, >50 percent PMN).[46]''. In addition, the font size of this phrase is inadvertently larger than the standard **Federal Register** text. Therefore, we are correcting these errors by replacing the phrase ''(>100 cells/לL, >50 percent PMN).[46]'' to ''(>100 cells/µL, >50 percent PMN).[46]''.

III. Waiver of Proposed Rulemaking and Delay in Effective Date

Under 5 U.S.C. 553(b) of the Administrative Procedure Act (APA), the agency is required to publish a notice of the proposed rule in the **Federal Register** before the provisions of a rule take effect. Similarly, section 1871(b)(1) of the Social Security Act (the Act) requires the Secretary to provide for notice of the proposed rule in the **Federal Register** and provide a period of not less than 60 days for public comment. In addition, section 553(d) of the APA, and section 1871(e)(1)(B)(i) mandate a 30-day delay in effective date after issuance or publication of a rule. Sections 553(b)(B) and 553(d)(3) of the APA provide for exceptions from the notice and comment and delay in effective date of the APA requirements; in cases in which these exceptions apply, sections 1871(b)(2)(C) and 1871(e)(1)(B)(ii) of the Act provide exceptions from the notice and 60-day comment period and delay in effective date requirements of the Act as well. Section 553(b)(B) of the APA and section 1871(b)(2)(C) of the Act authorize an agency to dispense with normal rulemaking requirements for good cause if the agency makes a finding that the notice and comment process is impracticable, unnecessary, or contrary to the public interest. In addition, both section 553(d)(3) of the APA and section 1871(e)(1)(B)(ii) of the Act allow the agency to avoid the 30-day delay in effective date where such delay is contrary to the public interest and an agency includes a statement of support.

We believe that this correcting document does not constitute a rule that would be subject to the notice and comment or delayed effective date requirements. This document corrects typographic errors and does not make substantive changes to the policies or payment methodologies that were adopted in the CY 2023 ESRD PPS final rule. Thus, this correcting document is intended to ensure that the information is accurately reflected in the final rule.

Even if this were a rulemaking to which the notice and comment and delayed effective date requirements applied, we find that there is good cause to waive such requirements. Undertaking further notice and comment procedures to incorporate the corrections in this document into the CY 2023 ESRD PPS final rule or delaying the effective date of the correction would be contrary to the public interest because it is in the public interest to ensure that the rule accurately reflects our policies as of the date they take effect. Further, such procedures would be unnecessary because we are not making any substantive revisions to the final rule, but rather, we are simply correcting the **Federal Register** document to reflect the policies that we previously proposed, received public comment on, and subsequently finalized in the CY 2023 ESRD PPS final rule. For these reasons, we believe there is good cause to waive the requirements for notice and comment and delay in effective date.

IV. Correction of Errors

In FR Doc. 2022–23778 of November 7, 2022 (87 FR 67136), make the following corrections:

1. On page 67170, in the second column; in footnote 14, at the bottom of the page, the website address ''*https://www.cms.gov/Medicare/Medicare-Feefor-Service-Payment/ESRDpayment/Educational_Resources*'' is corrected to read ''*https://www.cms.gov/Medicare/Medicare-Fee-for-Service-Payment/ESRDpayment/Educational_Resources.*''.

2. On page 67171, the first column; in footnote 15, at the bottom of the page, the website address ''*https://www.cms.gov/Medicare/Medicare-Feefor-Service-Payment/ESRDpayment/Educational_Resources*'' is corrected to read ''*https://www.cms.gov/Medicare/Medicare-Fee-for-Service-Payment/ESRDpayment/Educational_Resources.*''.

3. On page 67171, in the second column; in footnote 16, at the bottom of the page, the website address ''*https://www.cms.gov/Medicare/Medicare-Feefor-Service-Payment/ESRDpayment/Educational_Resources*'' is corrected to read ''*https://www.cms.gov/Medicare/Medicare-Fee-for-Service-Payment/ESRDpayment/Educational_Resources.*''.

4. On page 67194, in the first column; in the first complete paragraph, in line 22, the phrase ''100 cells/לL or >0.1 × 10/L'' is corrected to read ''>100 cells/µL or >0.1 × 10/L''.

5. On page 67195, in the third column; in the first paragraph, in line 11, the phrase ''(>100 cells/לL, >50 percent PMN).[46]'' is corrected to read ''(>100 cells/µL, >50 percent PMN).[46]''.

Elizabeth J. Gramling,

Executive Secretary to the Department, Department of Health and Human Services.

[FR Doc. 2022–28364 Filed 12–29–22; 8:45 am]

BILLING CODE 4120–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MB Docket No. 22–117; RM–11923; DA 22–1231; FR ID 117280]

Television Broadcasting Services Great Falls, Montana

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: On March 10, 2022, the Media Bureau, Video Division (Bureau) issued a *Notice of Proposed Rulemaking* (*NPRM*) in response to a petition for rulemaking filed by Scripps Broadcasting Holdings LLC (Petitioner), the licensee of KRTV(TV) (Station), channel 7, Great Falls, Montana, requesting the substitution of channel 22 for channel 7 at Great Falls in the Table of Allotments. For the reasons set forth in the *Report and Order* referenced below, the Bureau amends FCC regulations to substitute channel 22 for channel 7 at Great Falls.

DATES: Effective December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Joyce Bernstein, Media Bureau, at (202) 418–1647 or *Joyce.Bernstein@fcc.gov.*

SUPPLEMENTARY INFORMATION: The proposed rule was published at 87 FR 16157 on March 22, 2022. The Petitioner filed comments in support of the petition reaffirming its commitment to apply for channel 22. No other comments were filed.

The *Report and Order* substitutes channel 22 for channel 7 at Great Falls, Montana. According to the Petitioner, it has received many complaints from viewers unable to receive a reliable signal on VHF channel 7, and the Commission has recognized that VHF channels have certain characteristics that pose challenges for their use in providing digital television service. The Engineering Statement provided with the Petition confirmed that the proposed channel 22 contour would continue to reach virtually all of the population within the Station's current service area and fully cover the city of Great Falls. An analysis using the Commission's *TVStudy* software tool indicates that KRTV's move from channel 7 to channel 22 is predicted to create a small area where 554 persons are predicted to lose service. The loss area, however, is partially overlapped by the noise limited contour of other Scripps owned CBS affiliated stations. Once those other sources of CBS programming are factored into the loss analysis, the new loss area that would be created by the proposed channel substitution would contain only 255 persons, which is a level of service loss the Commission considers to be *de minimis.* Concurrence from the Canadian government was required and has been obtained.

This is a synopsis of the Commission's *Report and Order,* MB Docket No. 22–117; RM–11923; DA 22–1231, adopted November 29, 2022, and released November 29, 2022. The full text of this document is available for download at *https://www.fcc.gov/edocs.* To request materials in accessible formats for people with disabilities (braille, large print, electronic files, audio format), send an email to *fcc504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at 202–418–0530 (voice), 202–418–0432 (tty).

This document does not contain information collection requirements subject to the Paperwork Reduction Act of 1995, Public Law 104–13. In addition, therefore, it does not contain any proposed information collection burden ''for small business concerns with fewer than 25 employees,'' pursuant to the Small Business Paperwork Relief Act of 2002, Public Law 107–198, *see* 44 U.S.C. 3506(c)(4). Provisions of the Regulatory Flexibility Act of 1980, 5 U.S.C. 601–612, do not apply to this proceeding.

The Commission will send a copy of this *Report and Order* in a report to be sent to Congress and the Government Accountability Office pursuant to the Congressional Review Act, *see* 5 U.S.C. 801(a)(1)(A).

List of Subjects in 47 CFR Part 73

Television.

Federal Communications Commission.

Thomas Horan,

Chief of Staff, Media Bureau.

Final Rule

For the reasons discussed in the preamble, the Federal Communications Commission amends 47 CFR part 73 as follows:

PART 73—RADIO BROADCAST SERVICE

■ 1. The authority citation for part 73 continues to read as follows:

Authority: 47 U.S.C. 154, 155, 301, 303, 307, 309, 310, 334, 336, 339.

■ 2. In § 73.622(j), amend the Table of Allotments, under Montana, by revising the entry for Great Falls to read as follows:

§ 73.622 Digital television table of allotments.

* * * * *

(j) * * *

Community	Channel No.
* * *	* *
MONTANA	
* * *	* *
Great Falls	8, 17, *21, 22, 26
* * *	* *

[FR Doc. 2022–28312 Filed 12–29–22; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 660

[Docket No. 221206–0261]

RIN 0648–BL48

Magnuson-Stevens Act Provisions; Fisheries Off West Coast States; Pacific Coast Groundfish Fishery; Pacific Coast Groundfish Fishery Management Plan; Amendment 30; 2023–24 Biennial Specifications and Management Measures

Correction

In rule document 2022–26904, appearing on pages 77007 through 77036, in the issue of Friday, December 16, 2022 make the following change:

§ 660.74 Latitude/longitude coordinates defining the 180 fm (329 m) through 250 fm (457 m) depth contours [Corrected]

■ On page 77022, in ''Table 1b. to Part 660, Subpart C—2023'', in the second column, titled ''Area'', the fourteenth line for ''Longspine thornyhead'' should read, ''N of 34°27′ N. lat.''

[FR Doc. C1–2022–26904 Filed 12–29–22; 8:45 am]

BILLING CODE 0099–10–P

Proposed Rules

Federal Register
Vol. 87, No. 250
Friday, December 30, 2022

OFFICE OF PERSONNEL MANAGEMENT

5 CFR Part 532

RIN 3206–AO49

Prevailing Rate Systems; Redefinition of Certain Appropriated Fund Federal Wage System Wage Areas

AGENCY: Office of Personnel Management.

ACTION: Proposed rule.

SUMMARY: The Office of Personnel Management (OPM) is proposing a rule to redefine the geographic boundaries of the following appropriated fund Federal Wage System (FWS) wage areas for pay-setting purposes: Hagerstown-Martinsburg-Chambersburg, MD; Richmond, VA; Roanoke, VA; and Washington, DC. The proposed rule would redefine the Shenandoah National Park portions of Albemarle, Augusta, Greene, Page, and Rockingham Counties, VA, to the Washington, DC, wage area. This change is based on a recent consensus recommendation of the Federal Prevailing Rate Advisory Committee (FPRAC).

DATES: Send comments on or before January 30, 2023.

ADDRESSES: You may submit comments, identified by docket number and/or Regulatory Information Number (RIN) and title, by the following method:

• *Federal Rulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

All submissions received must include the agency name and docket number or RIN for this document. The general policy for comments and other submissions from members of the public is to make these submissions available for public viewing at *http://www.regulations.gov* as they are received without change, including any personal identifiers or contact information.

FOR FURTHER INFORMATION CONTACT: Ana Paunoiu, by telephone at (202) 606–2858 or by email at *pay-leave-policy@opm.gov.*

SUPPLEMENTARY INFORMATION: OPM is proposing a rule to redefine the geographic boundaries of the following appropriated fund FWS wage areas: Hagerstown-Martinsburg-Chambersburg, MD; Richmond, VA; Roanoke, VA; and Washington, DC. This proposed rule would redefine the Shenandoah National Park portions of Albemarle, Augusta, Greene, Page, and Rockingham Counties, VA, to the Washington, DC, wage area. Shenandoah National Park would become consolidated under the Washington, DC, FWS wage area so that the installation would be defined to a single wage area. This change is based on a recent recommendation of FPRAC, the statutory national labor-management committee responsible for advising OPM on matters affecting the pay of FWS employees. From time to time, FPRAC reviews the boundaries of wage areas and provides OPM with recommendations for changes if the Committee finds that changes are warranted.

As provided by 5 CFR 532.211, this regulation allows consideration of the following criteria when defining wage area boundaries: distance, transportation facilities, and geographic features; commuting patterns; and similarities in overall population, employment, and the kinds and sizes of private industrial establishments.

The Shenandoah National Park (approximately 105 miles long) is currently split among four FWS areas. When the FWS was first established, most of Shenandoah National Park was in the Hagerstown-Martinsburg-Chambersburg wage area. Over time, as a result of changes in Office of Management and Budget defined metropolitan statistical areas, the wage area definitions for some counties that comprise the Shenandoah National Park have been changed by OPM based on recommendations of FPRAC.

Presently, portions of the Shenandoah National Park are defined to the Hagerstown-Martinsburg-Chambersburg, MD; Richmond, VA; Roanoke, VA; and Washington, DC, FWS wage areas as follows:

(1) The Shenandoah National Park portion of Albemarle and Greene Counties, VA, is defined to the Richmond wage area;

(2) The Shenandoah National Park portion of Augusta County, VA, is defined to the Roanoke wage area;

(3) The Shenandoah National Park portion of Madison, Rappahannock, and Warren Counties, VA, is defined to the Washington, DC, wage area; and

(4) The Shenandoah National Park portion of Page and Rockingham Counties, VA, is defined to the Hagerstown-Martinsburg-Chambersburg, MD, wage area.

Albemarle and Greene Counties, except for the Shenandoah National Park portions, continue to be appropriately defined to the Richmond, VA, wage area. Augusta County, except for the Shenandoah National Park portion, continues to be appropriately defined to the Roanoke, VA, wage area. Page and Rockingham Counties, except for the Shenandoah National Park portions, continue to be appropriately defined to the Hagerstown-Martinsburg-Chambersburg, MD, wage area. Madison, Rappahannock, and Warren Counties continue to be appropriately defined to the Washington, DC, wage area.

There are 14 FWS National Park Service (NPS) employees working in the Shenandoah National Park portion of Madison County and 17 FWS NPS employees working in the Shenandoah National Park portion of Page County. So that the FWS employees working at Shenandoah National Park are not split among four wage areas, OPM proposes that the Shenandoah National Park portions of Albemarle, Augusta, Greene, Page, and Rockingham Counties be redefined to the Washington, DC, wage area. Shenandoah National Park would then be entirely defined to the Washington, DC, wage area. This change would provide equal pay treatment for FWS employees working at Shenandoah National Park.

FPRAC, the national labor-management committee responsible for advising OPM on matters concerning the pay of FWS employees, recommended this change by consensus. This change would be effective on the first day of the first applicable pay period beginning on or after 30 days following publication of the final regulations.

Regulatory Impact Analysis

This action is not a ''significant regulatory action'' under the terms of Executive Order (E.O.) 12866 (58 FR

51735, October 4, 1993) and is therefore not subject to review under E.O. 12866 and 13563 (76 FR 3821, January 21, 2011).

Regulatory Flexibility Act

OPM certifies that this rule will not have a significant economic impact on a substantial number of small entities.

Federalism

We have examined this rule in accordance with Executive Order 13132, Federalism, and have determined that this rule will not have any negative impact on the rights, roles and responsibilities of State, local, or tribal governments.

Civil Justice Reform

This regulation meets the applicable standard set forth in Executive Order 12988.

Unfunded Mandates Act of 1995

This rule will not result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any year and it will not significantly or uniquely affect small governments. Therefore, no actions were deemed necessary under the provisions of the Unfunded Mandates Reform Act of 1995.

Paperwork Reduction Act

This rule does not impose any new reporting or record-keeping requirements subject to the Paperwork Reduction Act.

List of Subjects in 5 CFR Part 532

Administrative practice and procedure, Freedom of information, Government employees, Reporting and recordkeeping requirements, Wages.

Office of Personnel Management.

Stephen Hickman,

Federal Register Liaison.

Accordingly, OPM is proposing to amend 5 CFR part 532 as follows:

PART 532—PREVAILING RATE SYSTEMS

■ 1. The authority citation for part 532 continues to read as follows:

Authority: 5 U.S.C. 5343, 5346; § 532.707 also issued under 5 U.S.C. 552.

■ 2. In Appendix C to subpart B amend the table by revising the wage area listings for the District of Columbia and the States of Maryland and Virginia to read as follows:

Appendix C to Subpart B of Part 532—Appropriated Fund Wage and Survey Areas

Definitions of Wage and Wage Survey Areas

* * * * *

District of Columbia

Washington, DC

Survey Area

District of Columbia:
  Washington, DC
Maryland:
  Charles
  Frederick
  Montgomery
  Prince George's
Virginia (cities):
  Alexandria
  Fairfax
  Falls Church
  Manassas
  Manassas Park
Virginia (counties):
  Arlington
  Fairfax
  Loudoun
  Prince William

Area of Application. Survey area plus:

Maryland:
  Calvert
  St. Mary's
Virginia (city):
  Fredericksburg
Virginia (counties):
  Albemarle (Only includes the Shenandoah National Park portion)
  Augusta (Only includes the Shenandoah National Park portion)
  Clarke
  Culpeper
  Fauquier
  Greene (Only includes the Shenandoah National Park portion)
  King George
  Madison
  Page (Only includes the Shenandoah National Park portion)
  Rappahannock
  Rockingham (Only includes the Shenandoah National Park portion)
  Spotsylvania
  Stafford
  Warren
West Virginia:
  Jefferson

* * * * *

Maryland

Baltimore

Survey Area

Maryland (city):
  Baltimore
Maryland (counties):
  Anne Arundel
  Baltimore
  Carroll
  Harford
  Howard

Area of Application. Survey area plus:

Maryland:
  Queen Anne's

Hagerstown-Martinsburg-Chambersburg

Survey Area

Maryland:
  Washington
Pennsylvania:
  Franklin
West Virginia:
  Berkeley

Area of Application. Survey area plus:

Maryland:
  Allegany
  Garrett
Pennsylvania:
  Fulton
Virginia (cities):
  Harrisonburg
  Winchester
Virginia (counties):
  Frederick
  Page (Does not include the Shenandoah National Park portion)
  Rockingham (Does not include the Shenandoah National Park portion)
  Shenandoah
West Virginia:
  Hampshire
  Hardy
  Mineral
  Morgan

* * * * *

Virginia

Norfolk-Portsmouth-Newport News-Hampton

Survey Area

Virginia (cities):
  Chesapeake
  Hampton
  Newport News
  Norfolk
  Poquoson
  Portsmouth
  Suffolk
  Virginia Beach
  Williamsburg
Virginia (counties):
  Gloucester
  James City
  York
North Carolina:
  Currituck

Area of Application. Survey area plus:

Virginia (city):
  Franklin
  Virginia (counties):
  Accomack
  Isle of Wight
  Mathews
  Northampton
  Southampton
  Surry
North Carolina:
  Camden
  Chowan
  Gates
  Pasquotank
  Perquimans
Maryland:
  Assateague Island part of Worcester

Richmond

Survey Area

Virginia (cities):

Colonial Heights
Hopewell
Petersburg
Richmond
Virginia (counties):
Charles City
Chesterfield
Dinwiddie
Goochland
Hanover
Henrico
New Kent
Powhatan
Prince George

Area of Application. Survey area plus:

Virginia (cities):
Charlottesville
Emporia
Virginia (counties):
Albemarle (Does not include the Shenandoah National Park portion)
Amelia
Brunswick
Buckingham
Caroline
Charlotte
Cumberland
Essex
Fluvanna
Greene (Does not include the Shenandoah National Park portion)
Greensville
King and Queen
King William
Lancaster
Louisa
Lunenberg
Mecklenburg
Middlesex
Nelson
Northumberland
Nottoway
Orange
Prince Edward
Richmond
Sussex
Westmoreland

Roanoke

Survey Area

Virginia (cities):
Radford
Roanoke
Salem
Virginia (counties):
Botetourt
Craig
Montgomery
Roanoke

Area of Application. Survey area plus:

Virginia (cities):
Bedford
Buena Vista
Clifton Forge
Covington
Danville
Galax
Lexington
Lynchburg
Martinsville
South Boston
Staunton
Waynesboro
Virginia (counties):
Alleghany
Amherst
Appomattox
Augusta (Does not include the Shenandoah National Park portion)
Bath
Bedford
Bland
Campbell
Carroll
Floyd
Franklin
Giles
Halifax
Henry
Patrick
Pittsburgh
Pulaski
Rockbridge
Wythe

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[FR Doc. 2022–28318 Filed 12–29–22; 8:45 am]

BILLING CODE 6325–39–P

NUCLEAR REGULATORY COMMISSION

10 CFR Part 35

[Docket No. PRM–35–22; NRC–2020–0141]

Reporting Nuclear Medicine Injection Extravasations as Medical Events

AGENCY: Nuclear Regulatory Commission.

ACTION: Petition for rulemaking; consideration in the rulemaking process.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) will consider in its rulemaking process issues raised in a petition for rulemaking (PRM), PRM–35–22, submitted by Ronald K. Lattanze on behalf of Lucerno Dynamics, LLC. The petitioner requested that the NRC amend its regulations to require reporting of certain nuclear medicine injection extravasations as medical events.

DATES: The docket for the petition for rulemaking, PRM–35–22, is closed on December 30, 2022.

ADDRESSES: Please refer to Docket ID NRC–2020–0141 when contacting the NRC about the availability of information for this action. You may obtain publicly available information related to this action by any of the following methods:

- *Federal Rulemaking Website:* Go to *https://www.regulations.gov* and search for Docket ID NRC–2020–0141. Address questions about NRC dockets to Dawn Forder; telephone: 301–415–3407; or email: *Dawn.Forder@nrc.gov.* For technical questions, contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly available documents online in the ADAMS Public Documents collection at *https://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''Begin Web-based ADAMS Search.'' For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, at 301–415–4737, or by email to *PDR.Resource@nrc.gov.* For the convenience of the reader, instructions about obtaining materials referenced in this document are provided in the ''Availability of Documents'' section.
- *NRC's PDR:* You may examine and purchase copies of public documents, by appointment, at the NRC's Public Document Room (PDR), Room P1 B35, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852. To make an appointment to visit the PDR, please send an email to *PDR.Resource@nrc.gov* or call 1–800–397–4209 or 301–415–4737, between 8:00 a.m. and 4:00 p.m. (ET), Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Andrew Carrera, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–415–1078, email: *Andrew.Carrera@nrc.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. The Petition

The NRC received and docketed a PRM (ADAMS Accession No. ML20157A266) dated May 18, 2020, filed by Ronald K. Lattanze on behalf of Lucerno Dynamics, LLC. On September 15, 2020, the NRC published a notice of docketing and request for public comment on the petition (85 FR 57148). The petitioner requested that the NRC amend its regulations in part 35 of title 10 of the *Code of Federal Regulations* (10 CFR), ''Medical Use of Byproduct Material,'' to require reporting of certain nuclear medicine injection extravasations as medical events. Extravasation is the infiltration of injected fluid into the tissue surrounding a vein or artery. Extravasation is not limited to the administration of radiopharmaceuticals.

A. Background

In 1980, the Commission amended the medical use regulations in 10 CFR part 35 to require the reporting of medical misadministrations (later renamed medical events) (45 FR 31701; May 14, 1980). Misadministration reporting allowed the NRC to investigate misadministrations for possible violations, evaluate licensee corrective actions, inform other licensees of potential problems, and take generic corrective actions. In this 1980 rulemaking, the Commission stated in a comment response that it did not consider extravasation to be a misadministration because extravasation frequently occurs in otherwise normal intravenous or intraarterial injections and that extravasations are virtually impossible to avoid.

The misadministration reporting requirements were updated in 1991 (56 FR 34104; July 25, 1991) with dose criteria based on the National Council on Radiation Protection and Measurements dose levels. These dose criteria were added to clarify the definition of misadministration and to exclude events involving diagnostic procedures, which the Commission considered low-risk. The next major update of 10 CFR part 35 was completed in 2002 (67 FR 20250; April 24, 2002). The term ''misadministration'' was replaced with ''medical event,'' the existing dose reporting criteria for patient exposures from medical events was retained, and a dose threshold of 0.5 Sv (50 rem) shallow dose equivalent to the skin was added. The extravasation exemption was not addressed.

B. Issues Raised in the Petition

The NRC identified two issues in the petition as follows:

Issue 1: The exemption of radiopharmaceutical extravasations from medical event reporting is based on the incorrect assertion that radiopharmaceutical extravasations are virtually impossible to avoid and therefore does not protect the public from unsafe irradiation. The petitioner requested that the NRC amend § 35.2, ''Definitions,'' to include a definition of ''extravasation'' as follows: ''Extravasation means the inadvertent injection or infusion of some or all of a radiopharmaceutical dosage into the tissue surrounding a vein or artery.''

Issue 2: Exemption of extravasations from medical event reporting requirements results in a lack of transparency to patients, the public, and the NRC. The petitioner also requested that the NRC amend § 35.3045(a)(1), ''Report and Notification of a Medical Event,'' by adding a new paragraph (iv) as follows: ''(iv) An extravasation that leads to an irradiation resulting in a localized dose equivalent exceeding 0.5 Sieverts (Sv) (50 rem).''

II. Public Comments on the Petition

A. Overview of Public Comments

On September 15, 2020, the NRC requested comments from the public on the petition and posed eight specific questions to gain information on the scope of and basis for the issues raised by the petitioner. The comment period closed on November 30, 2020. The NRC received 488 public comment submissions, including late-filed submissions. All the comment submissions received on this petition are available on *https://www.regulations.gov* under Docket ID NRC–2020–0141. A *comment submission* is a communication or document submitted to the NRC by an individual or entity, with one or more individual comments addressing a subject or issue. Eighty-eight submissions (from the Association for Vascular Access, Organization of Agreement States, congressional representatives, and private citizens) generally supported the petition, 396 submissions (from 11 medical communities and private citizens) generally opposed the petition, and two submissions were duplicates. The NRC reviewed and considered all comments in its evaluation of the petition.

B. Comments Received in Response to Specific Questions in the Docketing Request for Comment

The following is a summary of the feedback that the NRC received from the public on the eight specific questions posed in the notice of docketing and request for public comment on the petition.

Question 1: How frequently does radiopharmaceutical extravasation occur?

Comments Received: Twenty-five comments provided at least one of the following replies to the frequency of radiopharmaceutical extravasations: (1) there is clinical evidence that extravasation rates are greater than 1 percent of all administrations; (2) the frequency rate is unknown because extravasations are not reported; or (3) some groups are understating the frequency and potential harm to patients.

Four comments stated that the extravasation frequencies cited in the petition—average of 15 percent and a range of 2 to 23 percent of all administrations—are misleading and biased. Twenty-one additional comments stated that the frequency of either therapeutic or diagnostic extravasations is very rare, typically less than 1 percent of injections. Some of the 21 comments stated that this information is based on their own clinical observations, which these comments further stated is consistent with the results from peer-reviewed manuscripts.

Question 2: Do you know of any extravasations that have resulted in harm to patients? If so, what were the circumstances, the type of effect or harm, and the impacts.

Comments Received: Thirty-nine comments provided at least one of the following responses related to patient harm due to extravasations: (1) it is difficult to know if extravasations have resulted in patient harm because they are not tracked and rarely studied; (2) it can take months or years for the effects to become evident; (3) there are over 50 peer-reviewed papers that list the following adverse biological effects of extravasations—local pain, erythema, swelling, lesions, wet and dry desquamation, severe tissue damage, and radiation necrosis; (4) even diagnostic extravasations can lead to high radiation doses to injection site tissue; and (5) extravasations can hinder the ability to deliver therapeutic applications of nuclear medicine.

Forty-nine comments provided at least one of the following responses related to patient harm due to extravasations: (1) despite millions of nuclear medicine injections, there have been no serious cases of patient harm; (2) no instances of patient harm have been observed during decades on the job; and (3) there is a lack of clinical and research studies demonstrating instances of harm.

Question 3: For medical use licensees, does your facility currently monitor for radiopharmaceutical extravasations? If so, why and how do you monitor? If not, why not?

Comments Received: Sixteen comments stated that they are currently monitoring for extravasations through scans or other methods. Ten comments stated they have capabilities to monitor for and minimize extravasations but some clinics are doing a better job of monitoring than others. The same ten comments stated that requiring monitoring of extravasations would hold all clinics to a higher bar and increase injection quality and patient health. Four comments agreed that not all institutions monitor extravasations probably because they do not need to report extravasations.

Question 4: Do you expect that monitoring for extravasations and reviewing the results would improve radiopharmaceutical administration techniques at medical use licensee facilities? If so, how? If not, why not?

Comments Received: Thirty-six comments stated that monitoring extravasations would improve injection quality. The same comments stated that tracking would lead to a better understanding of how often extravasations occur, which would lead to better training to reduce the frequency of occurrence. In addition, the same comments noted that there is plenty of evidence in clinical observations and peer-reviewed literature that the frequency of extravasations can be reduced.

Twelve comments stated that monitoring and reviewing extravasations would not improve injection quality because highly trained professionals are already doing their best to prevent extravasations from occurring, so monitoring would only cause unnecessary burdens. Three comments stated that monitoring extravasations would not improve injection quality because extravasations occur largely as a result of patients having poor vascular structure. In addition, the same comments noted that, in particular, pediatric, geriatric, and chemotherapy patients often have compromised vascularity.

Question 5: Do you believe an NRC regulatory action requiring monitoring and review of extravasations would improve patient radiological health and safety? If so, how? If not, why not?

Comments Received: Fourteen comments stated that they had concerns about the health of patients for both therapeutic and diagnostic extravasations. The same comments stated that reporting of extravasations would lead to a better understanding of their frequency and severity, which could reduce how often they occur and lead to better patient health. One comment supported the petition because extravasations then could be tracked and their frequencies reduced to the benefit of patients.

Four comments stated that there would not be improvements to patient health due to monitoring and reporting of extravasations because they are not preventable. Seven comments stated that there would be no health benefits but there would be additional burdens to medical licensees. Two comments stated that monitoring for extravasations would negatively impact patient health because any manipulation of the injection site or addition of sensors could decrease blood flow, resulting in radioactive material remaining in the injection site for a longer period of time.

Question 6: Are there any benefits, not related to medical techniques, to monitoring and reporting certain extravasations as medical events? What would be the burden associated with monitoring for and reporting certain extravasations as medical events?

Comments Received: Forty-two comments stated that there would be considerable burdens to monitoring and reporting extravasations without much, if any, benefit. One commenter provided the example that 14 million diagnostic procedures are performed annually and if there is a 1 percent extravasation rate, then the result would be 140,000 medical events annually. The commenters stated that the main burdens they are concerned about are (1) reporting with minimal or no benefit, (2) considerable increase in paperwork, (3) considerable financial costs for practitioners and the entire medical field—possibly hundreds of millions of dollars, (4) the total time for extra monitoring and the frequency of nuclear medicine injections would allow for fewer patients to be seen, and (5) it may create false radiation safety concerns in patients and increase public fear concerning nuclear medicine.

Eight comments listed the following benefits to monitoring and reporting extravasations: (1) patients will know when an extravasation occurs, (2) it will lead to better diagnostics, (3) it will lead to better data for tracking, and (4) it will reduce medical workload and costs. Ten comments stated that those in opposition are overstating the burdens to the medical community. The comments also stated that the new detection methods are more cost effective for detecting extravasations than traditional computed tomography (CT) scans. Lastly, the comments noted that while there could be additional costs, it would increase the incentive to provide quality injections.

Question 7: If the NRC were to require that licensees report certain extravasations as medical events, what reporting criteria should be used to provide the NRC data that can be used to identify problems, monitor trends, and ensure that all licensees take corrective action(s)?

Comments Received: Nine comments were in favor of the petitioner's proposed 0.5 Sv (50 rem) reporting level because it is consistent with the level used for nuclear medicine both domestically and internationally. In addition, the same comments stated that the petitioner's proposed reporting level will lead to better monitoring and reduce the frequency of extravasations.

Eight comments stated the following concerns with the petitioner's proposed reporting level of 0.5 Sv (50 rem): (1) the criterion is arbitrary and does not harm the skin or tissue; (2) it takes more than 2 Gray (Gy) (200 rad) to cause impacts to skin in fluoroscopy procedures, which is much higher than the proposed criterion; and (3) if an extravasation does occur, the nuclear agents end up in the intended part of the body similar to a non-extravasated injection (*i.e.,* extravasations migrate from the lymphatic system and end up in the venous system). Nine comments did not support the petitioner's proposed criteria of 0.5 Sv (50 rem) because there is not a good or technically sound way to evaluate the dose to the tissue. Two comments stated that there should not be any criteria because there should be no reporting of extravasation.

Question 8: If the NRC requires reporting of extravasations that meet medical event reporting criteria, should a distinction be made between reporting extravasations of diagnostic and therapeutic radiopharmaceuticals? If so, why? If not, why not?

Comments Received: Eighteen comments stated that there should not be a distinction between diagnostics and therapeutics for classification of medical events because (1) if you exceed 0.5 Sv (50 rem), you could be causing harm regardless of the method, (2) diagnostic extravasations can cause harm or compromise scans, and (3) few facilities monitor diagnostic injections, but monitoring tools now exist that could lead to a better understanding of the frequency and help reduce the occurrence of extravasations. One comment supported the classification of therapeutic injection extravasations as medical events; explaining, however, that some diagnostic doses are used as ''test doses'' to determine injection quality; and stated that classifying these ''test doses'' as extravasations would be contradictory since they are meant to improve patient safety.

Twenty-five comments expressed concerns regarding classification of diagnostic extravasations as medical events because they are of such low dose that they do not cause harm or compromise scans. The same comments also noted that while therapeutic extravasations can cause tissue damage, they are extremely rare events that are dealt with under existing regulations. Lastly, most of these 25 comments do not support the classification of diagnostic or therapeutic extravasations as medical events, with an especially strong position against the classification of diagnostic extravasations as medical events.

C. NRC Response to Additional Public Comments

The NRC received thirty-three additional comments related to the petition that did not provide a direct response to the specific questions in the notice of docketing and request for public comment on the petition. In addition, the NRC received three comments that were out of scope. The NRC has binned these additional comments related to the petition into two categories. The following discussion provides a summary of each category and the NRC's response to the grouped comments, including—if appropriate—a summary of the basis for the response.

1. Comments Supporting the Petition

Comment: The NRC received nine comments supporting the proposed criteria of 0.5 Sv (50 rem) because the dose to the skin from extravasation can be estimated and this limit is 500 times higher than the dose from an ''ideal injection.''

NRC Response: The NRC disagrees with this comment. The NRC's medical event reporting dose threshold criteria (0.05 Sv [5 rem] effective dose equivalent, 0.5 Sv [50 rem] to an organ or tissue, or 0.5 Sv [50 rem] shallow dose equivalent to the skin) are conservative dose levels that would not be expected to cause patient harm. The criteria were implemented in part to screen out medical events involving diagnostic procedures because, as stated by the Commission, the NRC agrees that routine doses from diagnostic procedures represent a small amount of risk to the patient. On the dose levels, the Commission further commented that these levels correspond to a threshold well below the onset of acute, clinically detectable adverse effects that may be caused by exposure to ionizing radiation. Reporting extravasations at 0.5 Sv (50 rem) would result in many extravasation events of low radiation safety significance being reported. However, the NRC agrees that the topic of extravasation is important and therefore is considering the issues raised in the petition and assessing a more risk-informed reporting requirement in the rulemaking process.

Comment: The NRC received a comment stating that reporting extravasations is within the purview of the NRC. While administration of radiopharmaceuticals is a practice of medicine, misadministration of radiopharmaceuticals should be reported and this will not intrude on the practice of medicine.

NRC Response: The NRC agrees with this comment. Requiring medical event reporting of radiation-safety-significant extravasations is within the purview of the NRC's regulatory authority and supports the NRC's public health and safety mission.

Comment: The NRC received one comment concerning the lack of rationale explaining why extravasation of diagnostic injections should be exempted from medical event reporting.

NRC Response: The NRC agrees with this comment. The NRC questions whether excluding diagnostic administrations from an extravasation reporting requirement is supportable. Due to the smaller amounts of radioactivity used in diagnostic procedures, extravasation of diagnostic radiopharmaceuticals would rarely be expected to result in adverse tissue effects. However, while rare, significant extravasations of diagnostic radiopharmaceuticals with longer half-lives (such as thallium-201) could result in adverse tissue effects (Van der Pol et al., 2017) and would be considered a safety-significant medical event.

2. Comments Opposing the Petition

Comment: The NRC received four comments stating that extravasation is a generic medical issue outside the NRC's regulatory authority and is best managed at the institutional level.

NRC Response: The NRC disagrees with this comment. The radiation safety impact of some extravasations can be severe enough to warrant regulatory action, and reporting and tracking these incidents is of interest to the NRC.

Comment: The NRC received three comments concerning diagnostic extravasations. The comments state that minor diagnostic extravasations occur frequently but can be detected by scans and do not reduce scan quality or affect patient health. The comments further state that concerns regarding diagnostic extravasations are overstated and extravasation should be managed at the institutional level.

NRC Response: The NRC partially disagrees with this comment. While diagnostic extravasations of safety significance are rare, significant extravasations of certain diagnostic radiopharmaceuticals can cause adverse tissue effects, such as prolonged erythema and even skin necrosis (Van der Pol et al., 2017). The NRC is interested in medical event reporting of radiation-safety-significant extravasations, regardless of whether they involve diagnostic or therapeutic radiopharmaceuticals.

Comment: The NRC received 11 comments stating that the NRC's extravasation exemption is outdated.

Response: The NRC agrees with this comment. In 1980 the use of injectable radiopharmaceuticals involved diagnostic dosages of lower energy gamma emitting radionuclides. Since then, nuclear medicine has evolved to include use of higher energy positron-emitting diagnostic radiopharmaceuticals (for positron emission tomography imaging) and therapeutic radiopharmaceuticals, which use higher doses of radioactivity to treat certain cancers and diseases. The NRC is revisiting the exclusion of extravasation from medical event reporting in light of intervening changes in radiopharmaceuticals in the rulemaking process.

III. Reasons for Consideration

Although the petitioner requested that the NRC require the reporting of radiopharmaceutical extravasations exceeding 0.5 Sv (50 rem) localized dose equivalent, the NRC considered the issue more broadly and evaluated whether to require reporting of certain radiopharmaceutical extravasations of radiation safety significance as medical events. The NRC evaluated whether (1) the radiation safety risk from extravasations merits medical event reporting, (2) extravasations are preventable, (3) including extravasations in medical event reporting would align with the objectives of the NRC's medical event reporting regulations, and (4) regulating extravasations would align with the NRC's Medical Use Policy Statement (65 FR 47654; August 3, 2000). The staff recommends further evaluating, within the NRC's rulemaking process, medical event reporting of extravasations that require medical attention for a suspected radiation injury. The remaining paragraphs of Section III summarize the NRC's evaluation of the two issues identified in the petition.

Evaluation of Petition Issues

Issue 1: The exemption of radiopharmaceutical extravasations from medical event reporting is based on the incorrect assertion that radiopharmaceutical extravasations are virtually impossible to avoid and therefore does not protect the public from unsafe irradiation.

The petitioner stated that recent evidence demonstrates that extravasations are avoidable, invalidating the NRC's 1980 determination and subsequent exemption of extravasations from medical event reporting requirements. The petitioner asserted that reporting extravasations as medical events would reduce the amount of extravasations and protect patients from harmful injections. In addition, the petitioner asserted that diagnostic and therapeutic extravasations can result in significant radiation doses to injection site tissue, potentially causing adverse tissue reactions and cancer. The petitioner stated that diagnostic extravasations can also affect the accuracy of imaging study results, affect the patient's care, and may lead to unnecessary radiation dose due to repeat imaging studies. Lastly, the petitioner asserted that, per the NRC's Medical Use Policy Statement, the NRC has the obligation to regulate extravasations as necessary to provide for the radiation safety of workers and the general public.

NRC Evaluation: The NRC believes that the Commission's 1980 decision to exclude extravasations from medical event reporting should be reconsidered in the rulemaking process given the evolution of nuclear medicine since then. However, the NRC does not agree with the petitioner that the 1980 decision is invalidated because extravasations are avoidable. Although there have been many advancements in nuclear medicine since 1980, there is still no technology or technique that can fully prevent an extravasation. While monitoring technology could help identify extravasations earlier and improvements in training, skill, and tools could help reduce the prevalence of extravasations, there is no way to fully prevent extravasations from occurring. Even the most skilled clinician may infiltrate an injection due to many factors outside of the control of the clinician. Patient anatomy, age, body habitus, hydration, and prior medical treatment are all factors that may impact an intravenous administration.

The NRC agrees with the petitioner that medical event reporting of extravasations may focus some medical licensees on reducing their extravasation rate through implementation of quality improvement programs for intravenous administration of radiopharmaceuticals, and reducing the extravasation rate would improve radiation safety for patients.

The NRC agrees that certain extravasations can result in radiation-safety-significant doses to the tissue around the administration site, which could result in adverse tissue effects. However, published studies (Van der Pol et al., 2017; Hall et al., 2006) and input from the medical community and the Advisory Committee on the Medical Uses of Isotopes (ACMUI) indicate that due to the smaller amounts of radioactivity used in diagnostic procedures, extravasations of diagnostic radiopharmaceuticals are typically of low radiation safety significance and would rarely be expected to result in adverse tissue effects. The NRC agrees that extravasations of therapeutic radiopharmaceuticals, which deliver larger amounts of radioactivity to treat cancer and other ailments by killing cells, may cause tissue damage around the administration site (Van der Pol et al., 2017; Bonta et al., 2011; Tylski et al., 2018; Benjegerdes et al., 2017).

The NRC's Medical Use Policy Statement says, in part, that the NRC will not intrude into medical judgments affecting patients, except as necessary to provide for the safety of workers and the general public. The policy also states that the NRC will regulate radiation safety, when justified by the risk to the patient, primarily to assure the use of radionuclides is in accordance with the physician's directions. The NRC agrees that medical event reporting of certain extravasations would support these patient safety objectives of the Medical Use Policy Statement by potentially reducing the occurrence of radiation-safety-significant extravasations. Therefore, the NRC is considering the issues raised by the petitioner in a rulemaking process that will assess risk-informed reporting requirements for extravasations.

Issue 2: Exemption of extravasations from medical event reporting requirements results in a lack of transparency to patients, the public, and the NRC.

The petitioner asserted that the exemption of extravasations from medical event reporting requirements results in a lack of transparency to the patients, the public, and the NRC as the extravasation events are not documented in the NRC's Nuclear Material Events Database (NMED), which contains records of events involving nuclear material reported to the NRC. The petitioner asserted that this may result in patients and clinicians being unaware that the diagnostic image or intended therapy may have been compromised, and the NRC remains unaware when licensees misadminister radiopharmaceuticals resulting in doses that exceed medical event reporting limits.

NRC Evaluation: Under the NRC's current practice of excluding extravasations from medical event reporting, extravasations that result in suspected radiation injury, or even those that meet the NRC's public health and safety significance criteria for an abnormal occurrence, are not required to be reported to the NRC. The NRC agrees that reporting radiation-safety-significant extravasations would increase transparency between patients, physicians, and the NRC. If certain extravasations were required to be reported under § 35.3045, this would enhance transparency through medical event reporting requirements for notifying the patient, referring physician, and the NRC within 24 hours of discovering the event and through event notification reports published by the NRC. These event notifications would be publicly available on the NRC website. These extravasation events would be shared with and evaluated by the ACMUI on an annual basis. Additionally, the reporting and analysis of safety-significant extravasation events would allow the NRC to identify similarities in reports from multiple facilities and issue generic communications to share information that may help licensees to reduce the occurrence of radiation-safety-significant extravasations and mitigate their consequences.

IV. Availability of Documents

The documents identified in the following table are listed in the order in which they are cited in this notice and are available to interested persons through one or more of the following methods, as indicated.

Document	ADAMS accession No./web link/ **Federal Register** citation
Petition for Rulemaking (PRM–35–22)—Lucerno Dynamics, LLC, Petition to Amend 10 CFR 35.3045, May 18, 2020.	ML20157A266.
Notice of Docketing and Request for Comment on Petition for Rulemaking, Reporting Nuclear Medicine Injection Extravasations as Medical Events, September 15, 2020.	85 FR 57148.
Final Rule, Medical Use of Byproduct Material, April 24, 2002	67 FR 20250.
Final Rule, Quality Management Program and Misadministrations, July 25, 1991	56 FR 34104.

Document	ADAMS accession No./web link/ **Federal Register** citation
Final Rule, Misadministration Reporting Requirements, May 14, 1980	45 FR 31701.
Medical Use of Byproduct Material; Policy Statement, Revision, August 3, 2000	65 FR 47654.
Van der Pol, J., S. Voo S, J. Bucerius, and F.M. Mottaghy, "Consequences of Radiopharmaceutical Extravasation and Therapeutic Interventions: A Systematic Review." *European Journal of Nuclear Medicine and Molecular Imaging,* Vol. 44, No. 7, July 2017.	*https://pubmed.ncbi.nlm.nih.gov/28303300.*
Hall, N., J. Zhang, R. Reid, D. Hurley, and M. Knopp, "Impact of FDG Extravasation on SUV Measurements in Clinical PET/CT. Should we routinely scan the injection site?" *The Journal of Nuclear Medicine,* Vol. 41, Supplement 1, Pg. 115, May 2006.	*https://jnm.snmjournals.org/content/47/suppl_1/115P.2.*
Bonta, D.V., R.K. Halkar, and N. Alazraki, "Extravasation of a Therapeutic Dose of 131I-Metaiodobenzylguanidine: Prevention, Dosimetry, and Mitigation." *The Journal of Nuclear Medicine,* Vol. 52, No. 9, September 2011.	*https://pubmed.ncbi.nlm.nih.gov/21795365.*
Tylski, P., A. Vuillod, C. Goutain-Majorel, and P. Jalade, "Dose Estimation for an Extravasation in a Patient Treated with ^{177} Lu-DOTATATE." *Journal of Medical Physics,* Vol. 56, Supplement 1, December 2018.	*https://doi.org/10.1016/j.ejmp.2018.09.071.*
Benjegerdes KE, Brown SC, Housewright CD, "Focal Cutaneous Squamous Cell Carcinoma Following Radium-223 Extravasation." *Baylor University Medical Center Proceedings,* Vol. 30, No. 1, January 2017.	*https://pubmed.ncbi.nlm.nih.gov/28127143.*

V. Conclusion

For the reasons cited in this document, the NRC will consider the issues raised in the petition in the rulemaking process. The NRC will evaluate the current requirements and guidance for reporting of certain nuclear medicine injection extravasations as medical events. The NRC tracks the status of all rules and PRMs on its website at *https://www.nrc.gov/about-nrc/regulatory/rulemaking/rules-petitions.html.* The public can monitor further NRC action on the rulemaking titled, ''Reporting Nuclear Medicine Injection Extravasations as Medical Events,'' that will address the issues in this petition by searching for Docket ID NRC–2022–0218 on the Federal rulemaking website, *https://www.regulations.gov.* In addition, the Federal rulemaking website allows members of the public to receive alerts when changes or additions occur in a docket folder. To subscribe: (1) navigate to the docket folder (NRC–2022–0218); (2) click the ''Subscribe'' link; and (3) enter an email address and click on the ''Subscribe'' link. Publication of this document in the **Federal Register** closes Docket ID NRC–2020–0141 for PRM–35–22.

Dated December 22, 2022.

For the Nuclear Regulatory Commission.

Brooke P. Clark,

Secretary of the Commission.

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NATIONAL CREDIT UNION ADMINISTRATION

12 CFR Parts 701 and 714

[NCUA–2022–0185]

RIN 3133–AF49, 3133–AE96

Financial Innovation: Loan Participations, Eligible Obligations, and Notes of Liquidating Credit Unions

AGENCY: National Credit Union Administration (NCUA).

ACTION: Proposed rule.

SUMMARY: The NCUA Board (Board) is seeking comment on a proposed rule that would amend the NCUA's rules regarding the purchase of loan participations and the purchase, sale, and pledge of eligible obligations and other loans (including notes of liquidating credit unions). The proposed rule is intended to clarify the NCUA's current regulations and provide additional flexibility for federally insured credit unions (FICUs) to make use of advanced technologies and opportunities offered by the financial technology (fintech) sector. The proposal would also make conforming amendments to the NCUA's rule regarding loans to members and lines of credit to members by adding new provisions about indirect lending arrangements and indirect leasing arrangements. Finally, the proposal would make other conforming changes and technical amendments in other sections of the NCUA's regulations. The Board does not view these conforming and technical changes as substantive.

DATES: Comments must be received by February 28, 2023.

ADDRESSES: You may submit comments by any of the following methods (Please send comments by one method only):

- *Federal eRulemaking Portal: https://www.regulations.gov.* The docket number for this notice of proposed rulemaking is NCUA–2022–0185. Follow the instructions for submitting comments.
- *Mail:* Address to Melane Conyers-Ausbrooks, Secretary of the Board, National Credit Union Administration, 1775 Duke Street, Alexandria, Virginia 22314–3428.
- *Hand Delivery/Courier:* Same as mail address.

Public inspection: All public comments are available on the Federal eRulemaking Portal at: *https://www.regulations.gov* as submitted, except when impossible for technical reasons. Public comments will not be edited to remove any identifying or contact information.

If you are unable to access public comments on the internet, you may contact the NCUA for alternative access by calling (703) 518–6540 or emailing *OGCMail@ncua.gov.*

FOR FURTHER INFORMATION CONTACT: *For policy questions:* Laura Smith, Senior Credit Specialist, or Naghi Khaled, Director of Credit Markets, Office of Examination and Insurance, at (703) 518–6360; *for legal questions:* Frank Kressman, General Counsel, the Office of General Counsel, at (703) 518–6540; or by mail at National Credit Union Administration, 1775 Duke Street, Alexandria, VA 22314.

SUPPLEMENTARY INFORMATION:

I. Summary of the Proposed Rule

A. Background

The Board is proposing to amend §§ 701.21, 701.22, 701.23, and part 714 of the NCUA's regulations regarding the purchase of loan participations and the purchase, sale, and pledge of eligible obligations and other loans (including notes of liquidating credit unions).[1] The Board intends this proposal provide FICUs with additional flexibility to make use of advanced technologies and opportunities offered by the fintech sector. In addition, the proposed amendments are intended to clarify ambiguities related to loan participations and eligible obligations.

Over the last several years, the NCUA has modernized and updated several of its regulations to shift from a prescriptive to a principles-based approach. As a result of this effort, many of the agency's regulations are now principles-based, meaning the regulations provide a framework for a credit union to determine how to structure its operations. The NCUA's principles-based approach to rulemaking is intended to apply a broad, well-defined, set of principles governing the regulated activity. This principles-based approach enables a credit union to establish and adjust its policies and procedures to reflect its board-established risk-tolerance levels, provided those policies and procedures continue to meet the principles outlined in the regulation, including safety and soundness and compliance considerations.

The Board believes shifting to a more principles-based approach with respect to loan participations and eligible obligations is appropriate and will be beneficial to FICUs. By removing certain prescriptive limits and other qualifying conditions, and replacing them with risk-focused, principles-based requirements, the Board believes this proposal will advance the agency's efforts to strike an appropriate balance between mitigating risk to the National Credit Union Share Insurance Fund (Share Insurance Fund), protecting credit union members and fostering growth and stability in the credit union system. In addition, this shift would provide FICUs with flexibility to innovate how they manage their balance sheets while offering new or enhanced services to their members. The Board also believes the proposed changes would increase FICUs' ability to engage in lending arrangements with other financial institutions and third parties, including fintech companies providing lending services, expanding their access to diverse loan origination channels, new markets and potential new services to their members. Finally, the Board notes that this proposal would address part of one of the strategic objectives outlined in the 2022 NCUA Annual Performance Plan, which is to ensure NCUA policies and regulations appropriately address emerging and innovative financial technologies.

B. Overview of Proposed Changes

The proposed rule would remove certain prescriptive limitations and other qualifying requirements relating to eligible obligations and provide credit unions with additional flexibility to purchase eligible obligations of their members. Removing the current prescriptive limitations and other qualifying requirements will allow federal credit unions (FCUs) additional flexibility to engage with the advanced technologies and other opportunities offered by the fintech sector. The greater flexibility and individual autonomy will also allow FCUs to establish their own risk tolerance limits and governance policies for these activities, while codifying due diligence, risk assessment, compliance and other management processes that are consistent with the Board's long-standing expectations for safe, sound, fair and affordable lending practices.

The proposed rule would also provide credit unions with additional flexibility to participate in loans acquired through indirect lending arrangements, allowing FICUs to utilize advanced technologies and opportunities offered by the fintech sector.

As discussed in greater detail in the section-by-section analysis, the Board is proposing to amend § 701.21 of the NCUA's regulations to add new paragraph (c)(9) regarding indirect lending and indirect leasing arrangements. The new paragraph is intended to replace the language defining indirect lending and indirect leasing arrangements under current § 701.23(b)(4)(iv), which would be removed under this proposal for the reasons explained below.

The proposal would also amend § 701.22 of the NCUA's regulations. In particular, the proposal requests comment on certain clarifying amendments to the introductory paragraph, and would codify NCUA Legal Opinion 15–0813, Loan Participations in Indirect Loans—Originating Lender.[2] Through the codification of Legal Opinion 15–0813, this proposed rule would clarify that a FICU engaged in an indirect lending relationship can meet the definition of ''eligible organization'' under § 701.22 of the NCUA's regulations, provided the FICU meets certain conditions. Specifically, under this proposal, for purposes of § 701.22, a FICU would be considered the originating lender and meet the definition of an ''eligible organization'' if the FICU makes the final underwriting decision regarding the loan, and the loan is assigned to the purchaser very soon after the inception of the obligation to extend credit.

The Board notes that it intends the codification of the aforementioned legal opinion to clarify that a FICU can meet the definition of ''originating lender'' in certain transactions where the FICU is engaging in indirect lending arrangements with fintech companies and other third-party loan acquisition channels, such as Credit Union Service Organizations (CUSOs) and other loan-originating retailers.

In addition, this proposed rule would amend § 701.23 of the NCUA's current regulations as follows:

- Proposing certain clarifying and conforming amendments to the introductory paragraph to § 701.23.
- Removing the CAMELS ratings and well-capitalized requirements under § 701.23(b)(2) for FCU purchases of certain non-member loans from FICUs.
- Narrowing the application of the 5-percent limit on the purchase of eligible obligations to notes of a liquidating credit union.
- Adding safety and soundness requirements to section § 701.23(b)(6)(i)–(vi) concerning the purchase of eligible obligations, to offset risks associated with removing the CAMELS and well-capitalized requirements from § 701.23(b)(2), and narrowing the application of the 5-percent limit to notes of liquidating credit unions. Safety and soundness and compliance requirements would apply to all FCUs engaged in the purchase of eligible obligations and notes from a liquidating credit union. In particular, the proposed rule would require an FCU purchasing eligible obligations or notes from a liquidating credit union to:
  - establish written, board-approved policies, risk assessments, and risk management process requirements that are commensurate with the size, scope, type, complexity, and level of risk posed by the planned purchase activities. These policies would include underwriting standards for the loans, ongoing performance and risk monitoring, including compliance risk, tailored to the types of loans purchased and the sellers as applicable, and

[1] Note that the terms credit union, federal credit union, federally insured state-chartered credit union, corporate credit union, and FICU are used throughout the document and are not necessarily interchangeable. Specifically, while § 701.23 applies to FCUs only, § 701.22 applies to all federally insured consumer credit unions, and § 701.21 has provisions that apply to all federally insured credit unions.

[2] NCUA Legal Op. 15–0813 (Aug. 10, 2015) *available at https://www.ncua.gov/regulation-supervision/legal-opinions/2015/loan-participations-indirect-loans-originating-lenders.*

portfolio concentration limits by loan types and risk categories in relation to net worth;

◦ conduct due diligence on a seller prior to the purchase; and

◦ require the written loan purchase agreements to contain certain contract language and provisions (similar to the standards currently established for loan participation agreements under § 701.22 of the NCUA's regulations);

◦ provide for a legal review and assessment of applicable loan purchase agreements or contracts to protect the FCU's legal and business interests from undue risk.

• Revising the definition of an eligible obligation under § 701.23(a)(1) to clarify the distinction between transactions treated as loan participations and those treated as eligible obligations.

• Revising the applicability of the 5-percent limit, discussed in more detail later in this document, from covering the purchase of most eligible obligations to only ''notes'' purchased by an FCU from a liquidating credit union.

• Revising the ''grandfathered purchases'' section of the current rule to include eligible obligation purchases that were executed before the effective date of this proposed rule (if adopted) and complied with § 701.23 at the time the transaction was executed, subject to safety and soundness and compliance considerations.

• Adding safety and soundness requirements to § 701.23(c) concerning the sale of eligible obligations, requiring the selling FCU to do the following:

◦ obtain a legal review and assessment of all applicable loan sale agreements or contracts to protect the FCU's legal and business interests; and

◦ identify the specific loan(s) being sold either directly in the written loan sale agreement or through a document that is incorporated by reference into the loan sale agreement.

The Board is also proposing to amend § 714.9 of the NCUA's regulations to make certain conforming amendments related to proposed changes to § 701.23(b)(4).

Finally, the proposal would make certain other conforming changes and technical amendments in other sections of the NCUA's regulations. The Board does not view these additional conforming technical changes as substantive.

II. Legal Authority

Section 120(a) [3] of the Federal Credit Union Act (FCU Act or Act) authorizes the Board to prescribe rules and regulations for the administration of the Act.[4] Similarly, section 209 [5] of the FCU Act authorizes the Board to prescribe such rules and regulations as it may deem necessary or appropriate to carry out the share insurance provisions of subchapter II of the Act. In addition, section 206 of the FCU Act provides the Board with broad authority to take enforcement action against a FICU or an ''institution-affiliated party'' [6] that is engaging or has engaged, or the Board has reasonable cause to believe that is about to engage, in an unsafe or unsound practice in conducting the business of such credit union.[7] Congress chose not to define ''unsafe or unsound practices'' in the FCU Act, leaving determinations regarding which actions are unsafe or unsound to the Board.

Section 107(5)(E) of the FCU Act authorizes FCUs to engage in participation lending with other credit unions, credit union organizations, or financial organizations in accordance with written policies of the board of directors.[8] Section 107(5)(E) also provides that a credit union that originates a loan for which participation arrangements are made in accordance with this subsection shall retain an interest of at least 10 per centum of the face amount of the loan.[9]

Section 107(13) of the FCU Act authorizes FCUs, in accordance with rules and regulations prescribed by the Board, to purchase, sell, pledge, or discount or otherwise receive or dispose of, in whole or in part, any eligible obligation (as defined by the Board) of its members.[10] In addition, section 107(13) authorizes FCUs, in accordance with rules and regulations prescribed by the Board, to purchase from any liquidating credit union notes made by individual members of the liquidating credit union at such prices as may be agreed upon by the board of directors of the liquidating credit union and the board of directors of the purchasing credit union, but no purchase may be made under authority of this paragraph if, upon the making of that purchase, the aggregate of the unpaid balances of notes purchased under authority of this paragraph would exceed 5 per centum of the unimpaired capital and surplus of the credit union.[11]

Section 107(14) of the FCU Act authorizes FCUs, subject to regulations of the Board, to sell all or a part of its assets to another credit union, to purchase all or part of the assets of another credit union, and to assume the liabilities of the selling credit union and those of its members.[12]

III. Section-By-Section Analysis

A. Part 701 Organization and Operation of Federal Credit Unions

As discussed in more detail below, this proposal would make several changes to sections in part 701 of the NCUA's regulations. The Board requests comment on all aspects of the proposal and on specific questions and issues mentioned below. These changes are intended to clarify numerous provisions regarding loans to members and lines of credit to members under § 701.21; loan participations under § 701.22; and the purchase, sale, and pledge of eligible obligations under § 701.23. In addition, the proposal would amend the NCUA's current regulatory requirements under §§ 701.22 and 701.23. The amended requirements would provide FICUs authority and autonomy to innovate and transact business with fintech companies and other institutions that provide services associated with the origination and sale of loans made to members of FICUs.

Section 701.21 Loans to Members and Lines of Credit to Members

As discussed in more detail below, this proposal would, as a conforming amendment, add new provisions to § 701.21 regarding indirect lending

[3] 12 U.S.C. 1766(a) (The Board may prescribe rules and regulations for the administration of 12 U.S.C. chapter 14 (including, but not by way of limitation, the merger, consolidation, and dissolution of corporations organized under the chapter). Any central credit union chartered by the Board shall be subject to such rules, regulations, and orders as the Board deems appropriate and, except as otherwise specifically provided in such rules, regulations, or orders, shall be vested with or subject to the same rights, privileges, duties, restrictions, penalties, liabilities, conditions, and limitations that would apply to all Federal credit unions under the chapter.).

[4] Sections 1751–1795k.

[5] Section 1789(11) (providing in relevant part as follows: ''In carrying out the purposes of this subchapter, the Board may—[. . .] prescribe such rules and regulations as it may deem necessary or appropriate to carry out the provisions of [12 U.S.C. 1781 − 1790e].'').

[6] *See* section 1786(r) (providing that for purposes of the FCU Act, the term ''institution-affiliated party'' means—(1) any committee member, director, officer, or employee of, or agent for, an insured credit union; (2) any consultant, joint venture partner, and any other person as determined by the Board (by regulation or on a case-by-case basis) who participates in the conduct of the affairs of an insured credit union; and (3) any independent contractor (including any attorney, appraiser, or accountant) who knowingly or recklessly participates in—(A) any violation of any law or regulation; (B) any breach of fiduciary duty; or (C) any unsafe or unsound practice, which caused or is likely to cause more than a minimal financial loss to, or a significant adverse effect on, the insured credit union.).

[7] Section 1786.

[8] Section 1757(5)(e).

[9] *Id.*

[10] Section 1757(13).

[11] *Id.*

[12] Section 1757(14).

arrangements and indirect leasing arrangements. The new provisions are intended to take the place of a provision in current § 701.23, which would be removed under the proposal. No other changes to § 701.21 are proposed.

Section 701.21(c) General Rules

New § 701.21(c)(9) Indirect Lending and Indirect Leasing Agreements

For reasons discussed in the preamble discussion on current § 701.23(b)(4), the NCUA is proposing to delete paragraph (b)(4)(iv) regarding indirect lending from § 701.23. Current § 701.23(b)(4)(iv) excludes certain loans acquired through indirect lending arrangements and indirect leasing arrangements from the 5-percent limit on the aggregate of the unpaid balance of certain loans purchased under § 701.23. While the language excluding loans and leases acquired through indirect lending and indirect leasing arrangements would no longer be needed in § 701.23(b)(4), the definition of such arrangements is still relevant for purposes of other provisions in the NCUA's regulations. Under current paragraph (b)(4), and NCUA's long-standing interpretation,[13] loans acquired by an FCU pursuant to an indirect lending arrangement are considered loans made by the FCU under § 701.21, rather than loans purchased under § 701.23. Accordingly, the Board is proposing to add to § 701.21 new paragraph (c)(9) regarding indirect lending and indirect leasing arrangements. The new paragraph is intended to replace the language defining indirect lending and indirect leasing arrangements under current § 701.23(b)(4)(iv).

New § 701.21(c)(9)(i) Definitions

Proposed new § 701.21(c)(9)(i) would define the terms ''indirect leasing arrangement'' and ''indirect lending arrangement'' for purposes of the NCUA's regulations. Current § 701.23(b)(4)(iv) provides that an indirect lending or indirect leasing arrangement that is classified as a loan and not the purchase of an eligible obligation because the FCU makes the final underwriting decision, and the sales or lease contract is assigned to the FCU very soon after it is signed by the member and the dealer or leasing company, is excluded in calculating the 5-percent limit. The NCUA believes splitting the provision in paragraph (b)(4)(iv) into two definitions will help clarify the existing requirements. Accordingly, proposed new § 701.21(c)(9)(i) would provide that the term *indirect leasing arrangement* means a written agreement to purchase leases from the leasing company where the purchaser makes the final underwriting decision, and the lease agreement is assigned to the purchaser very soon after it is signed by the member and the leasing company. Proposed new paragraph (c)(9)(i) would provide further that the term *indirect lending arrangement* means a written agreement to purchase loans from the loan originator where the purchaser makes the final underwriting decision regarding making the loan, and the loan is assigned to the purchaser very soon after the inception of the obligation to extend credit.

Both proposed new definitions would use language that is generally similar, but not identical, to the language in current § 701.23(b)(4)(iv). The NCUA is proposing to revise the language used in current paragraph (b)(4)(iv) to clarify the different requirements that apply to indirect leasing arrangements and indirect lending arrangements. The proposed changes are intended to clarify but not change the current meaning of both terms.

The Board specifically requests comment on whether proposed paragraph (c)(9) would have a material impact on credit unions' existing and future indirect lending arrangements, indirect leasing arrangements, or both.

New § 701.21(c)(9)(ii) Indirect Lending

Proposed new § 701.21(c)(9)(ii), consistent with current § 701.23(b)(4)(iv), would clarify the difference between loans made pursuant to indirect lending arrangements under § 701.21 and loans purchased under § 701.23. Current § 701.23(b)(4)(iv) excludes loans acquired pursuant to certain indirect lending arrangements from the 5-percent limit under current paragraph (b)(4). Paragraph (b)(4)(iv) provides that an *indirect lending* or indirect leasing arrangement that *is classified as a loan and not the purchase* of an eligible obligation *because* the FCU makes the final underwriting decision, and the sales or lease contract is assigned to the FCU very soon after it is signed by the member and the dealer or leasing company, is excluded from calculating the 5-percent limit.[14] As previously mentioned, current § 701.23(b)(4)(iv) would be removed under this proposal. Accordingly, proposed new § 701.21(c)(9)(ii) would provide that a loan acquired pursuant to an indirect lending arrangement, and that meets the requirements of § 701.21, is classified as a loan and not the purchase of a loan for purposes of the NCUA's regulations, which are codified in chapter VII of title 12 of the Code of Federal Regulations.

New § 701.21(c)(9)(iii) Indirect Leasing

Proposed new § 701.21(c)(9)(iii), consistent with current §§ 701.23(b)(4)(iv) and 714.9, would clarify the difference between leases made pursuant to indirect leasing arrangements under § 714.2(b)[15] and leases purchased under § 701.23. Current § 701.23(b)(4)(iv) excludes leases acquired pursuant to certain indirect leasing arrangements from the 5-percent limit under current paragraph (b)(4). Paragraph (b)(4)(iv) provides that an indirect lending or *indirect leasing arrangement* that *is classified as a loan and not the purchase* of an eligible obligation *because* the FCU makes the final underwriting decision, and the sales or lease contract is assigned to the FCU very soon after it is signed by the member and the dealer or leasing company, is excluded in calculating the 5-percent limitation.[16] Similarly,

[13] *See, e.g.,* NCUA Legal Op. 97–0546 (Aug. 6, 1997), *available at https://www.ncua.gov/regulation-supervision/legal-opinions/1997/indirect-lending.*

[14] (emphasis added); *see also, e.g.,* NCUA Legal Op. 97–0546 (Aug. 6, 1997) (providing in relevant part: ''FCUs may participate in indirect lending arrangements under the authority to make loans to members, 12 U.S.C. 107(5); 12 CFR 701.21, rather than the authority to purchase eligible obligations, 12 U.S.C. 107(13); 12 CFR 701.23, as long as two conditions are met. First, the FCU must make the final underwriting decision. That is, before the retailer and the member complete the loan or sales contract, the FCU must review the application and determine that the transaction conforms to its lending policies. This is because an FCU may not delegate its lending authority to a third party. Second, the retailer must assign the loan or sales contract to the FCU very soon after it is completed. Assignment close in time to the making of the loan allows the retailer to function as the facilitator of the loan while the FCU remains the true lender. As the time between completion and assignment of the loan lengthens, the FCU's payment to the retailer becomes the purchase of the loan rather than part of the processing of the loan.'').

[15] (Providing: ''[An FCU] may engage in indirect leasing. In indirect leasing, a third party leases property to [the FCU's] member and [the FCU] then purchases that lease from the third party for the purpose of leasing the property to [the FCU's] member. [The FCU does] not have to purchase the leased property if [it complies] with the requirements of § 714.3.'').

[16] *Id.* (emphasis added); *see also* 12 CFR 714.2(b) & 714.9; *and* NCUA Legal Op. 00–0811 (Nov. 2000) (providing in part: ''NCUA's leasing regulation recognizes that FCUs may engage in the leasing of personal property and does not distinguish between consumer and business leasing. 12 CFR part 714. The authority of FCUs to engage in secured lending is the basis for their authority to engage in leasing. Therefore, FCU leasing generally must comply with the statutory and regulatory requirements applicable to secured lending, including the member business loan rule. 12 CFR part 723. Our leasing regulation, however, notes exceptions from certain provisions of the lending rules that are not pertinent to leasing; for example, the interest rate ceilings. 12 CFR 714.10, 701.21(c)(7). In a lease, the

current § 714.9 provides that an FCU's indirect leasing arrangements are not subject to the eligible obligation limit if they satisfy the provisions of § 701.23(b)(3)(iv) that require that an FCU make the final underwriting decision and that the lease contract is assigned to the FCU very soon after it is signed by the member and the dealer or leasing company. Accordingly, proposed new § 701.21(c)(9)(iii) would provide that a lease acquired pursuant to an indirect leasing arrangement, and that meets the requirements of part 714 of the NCUA's regulations, is classified as a lease and not the purchase of a lease for purposes of the NCUA's regulations, which are codified in chapter VII of title 12 of the Code of Federal Regulations.

Section 701.22 Loan Participations

As discussed in more detail below, the proposal would make several clarifying amendments to § 701.22. These changes are primarily intended to clarify FCUs' authority to purchase loan participations and the requirements applicable to the purchase of loan participations by federally insured, state-chartered credit unions (FISCUs).

701.22 Introductory Paragraph

The introductory paragraph to current § 701.22 sets forth the scope and limitations of the section. The NCUA Board added the introductory paragraph to § 701.22 as part of a final rule it approved in 2013 (2013 Final Rule).[17] The introductory paragraph was intended to clarify several issues related to the scope and applicability of § 701.22. In particular, the 2013 Final Rule explained as follows in the remainder of this paragraph. The introductory text clarified the scope of the rule and helps distinguish a loan participation under § 701.22 from an eligible obligation under § 701.23. Further, it clarified that the rule applies to a natural person FICU's purchase of a loan participation where the borrower is not a member of that credit union. Generally, an FCU's purchase, in whole or in part, of its member's loan is covered by NCUA's eligible obligations rule at § 701.23. Additionally, by a cross-reference to Part 741 of NCUA's regulations, the rule also was made applicable to natural person FISCUs. The Board noted that corporate credit unions are subject to the loan participation requirements set forth in Part 704 and, therefore, are not subject to § 701.22 of NCUA's regulations. [18]

The introductory paragraph has seven separate substantive provisions. First, the paragraph provides that this section applies only to loan participations as defined in the section. Second, it provides that the section does not apply to the purchase of an investment interest in a pool of loans. Third, it provides that the section establishes the requirements a FICU must satisfy to purchase a loan participation. Fourth, it provides that the section applies to a FICU's purchase of a loan participation only where the borrower is not a member of the purchasing FICU and where a continuing contractual obligation between the seller and purchaser is contemplated. Fifth, it provides that § 701.23 generally applies to an FCU's purchase of all or part of a loan made to one of its members. Sixth, it provides that § 741.225 requires FISCUs to comply with the requirements of §§ 701.22 through 741.225 provides that FISCUs are exempt from the borrower membership requirement in current § 701.22(b)(4). Seventh, the paragraph provides that the section does not apply to corporate credit unions as defined in part 704.

In the 2013 Final Rule, the Board added a similar introductory paragraph to § 701.23 regarding the purchase, sale, and pledge of eligible obligations to clarify the scope of that section and distinguish loan participations from eligible obligations. The provisions included in that introductory paragraph are discussed in detail later in the part of the preamble on the introductory paragraph to § 701.23.

Since adopting the prefatory language in both sections, the NCUA has received inquiries from NCUA examiners, FICUs, fintech companies, and other parties who have expressed confusion about how to interpret many of these provisions. This confusion has led to inconsistent reporting of loan interests by FICUs and uncertainty about which of the two sections, § 701.22 or § 701.23, to apply to certain transactions, particularly innovative programs that have been designed by FICUs after 2013. In addition, the Board is concerned that continued confusion about lines of authority in this area could discourage FICUs from entering into certain safe, sound and compliant loan participation, purchase, or sale agreements that are within their statutory authority.

One significant issue with the current introductory paragraph to § 701.22 that parties have raised is when a FICU's partial loan purchase is subject to that section. In particular, parties have cited the continuing contractual obligation qualifier as a source of confusion. The third sentence in the introductory paragraph to current § 701.22 provides that the section applies only to a FICU's purchase of a loan participation where the borrower is not a member of that credit union *and where a continuing contractual obligation between the seller and purchaser is contemplated.*[19] The fourth sentence in the paragraph provides further that, generally, an FCU's purchase of all or part of a loan made to one of its own members, subject to a limited exception for certain well-capitalized FCUs in § 701.23(b)(2), *where no continuing contractual obligation between the seller and purchaser is contemplated,* is governed by § 701.23 of this part.[20] Similarly, the introductory paragraph to § 701.23 provides that § 701.23 governs an FCU's purchase, sale, or pledge of all or part of a loan to one of its own members, subject to a limited exception for certain well-capitalized FCUs, *where no continuing contractual obligation between the seller and purchaser is contemplated.*[21]

In practice, however, purchase agreements, regardless of whether the transactions involve the purchase of an eligible obligation or a loan participation, frequently contain some form of continuing contractual obligation between the buyer and the seller, including representations and warranties regarding the loans and loan repurchase agreements, servicing agreements, and other similar types of ongoing obligations set forth under the agreements. The Board believes the continuing contractual obligation clauses in the third and fourth sentences in the introductory paragraphs to current § 701.22 are unnecessary when determining whether a loan purchase agreement qualifies as either a loan participation or an eligible obligation.

In addition to the concerns explained above, the clause *where the borrower is not a member of that credit union* in the first part of the third sentence of the introductory paragraph conflicts with another provision in § 701.22. This language could be misinterpreted to suggest that § 701.22 does not apply to a partial loan purchase where the borrower is a member of the purchasing credit union, even when the transaction otherwise meets the definition of a loan participation under § 701.22. This clause directly conflicts with the more specific requirement in § 701.22(b)(4),

lessee's payments are periodic rental payments, not the repayment of principal and interest as in a loan.'').

[17] 78 FR 37946 (June 25, 2013) (footnote omitted).

[18] *Id.* at 37948.

[19] Emphasis added.

[20] Emphasis added.

[21] Emphasis added.

which provides that the borrower must become a member of one of the participating credit unions before the purchasing FICU purchases a participation interest in the loan. The NCUA has long interpreted the more specific language in paragraph (b)(4) as controlling and has applied the requirements of § 701.22 to partial loan purchases where the purchase meets the definition of a loan participation and the borrower is a member of the purchasing FICU.

Accordingly, the NCUA believes the removal of this clause will serve to clarify and reduce confusion when § 701.22 applies to certain transactions. As part of this proposal, the Board requests comment on whether deleting the fourth and fifth sentences in the introductory paragraph to current § 701.22 would clarify when the section applies to certain transactions. After considering any public comments received on this issue, the Board may adopt these amendments in a final rule based on this proposal.

The NCUA recognizes that whether the purchase of a partial loan is a loan participation under § 701.22 or a loan purchase under § 701.23 may still be uncertain in some instances even if these sentences are removed. The NCUA believes, however, that other provisions in § 701.22, such as the definition of loan participation and the conditions outlined in paragraph (b), make clear which transactions are subject to the requirements of § 701.22.

As discussed in more detail in the part of the preamble below regarding § 701.23, the Board is also considering deleting the continuing contractual obligations sentence in current § 701.23, subject to comments received on this proposal. The Board intends this change to work in conjunction with the proposed changes to the introductory paragraph to current § 701.22.

The Board is proposing no other changes to the introductory paragraph to current § 701.22. Another provision in the introductory paragraph that is often misread, however, is the sentence providing that § 701.22 does not apply to the *purchase of an investment interest in* a pool of loans. That sentence is intended to clarify that the purchase of such investment interests, to the extent they are permitted, are governed by part 703 of the NCUA's regulations for FCUs (and under part 741 of the NCUA's regulations and as authorized under state law for FISCUs) and not § 701.22. This continues to be the case under this proposal. The NCUA notes further that this qualification to the section makes clear that § 701.22 neither applies to nor authorizes FICU investments in either asset-backed securities or the purchase of other similar investment interests in pools of loans.[22] The requirements of § 701.22 apply to each individual loan a FICU purchases a loan participation interest in.[23]

If all the changes proposed above are adopted in a final rule, the introductory text of § 701.22 would provide the section applies only to loan participations as defined in paragraph (a). It does not apply to the purchase of an investment interest in a pool of loans. The section establishes the requirements a federally insured credit union must satisfy to purchase a participation in a loan. Federally insured state-chartered credit unions are required by § 741.225 to comply with the loan participation requirements of the section. The section does not apply to corporate credit unions, as that term is defined in § 704.2.

Section 701.22(a)

The proposed rule would add a second sentence to the current definition of ''originating lender'' in § 701.22(a) to codify and further clarify a 2015 NCUA legal opinion (2015 Opinion) regarding loan participations in indirect loans.[24] The NCUA's 2013 Final Rule amended the loan participation regulation to, among other things, clarify that the originating lender must participate in the loan throughout the life of the loan.[25] In the 2013 Final Rule, the NCUA explained that this requirement derives from sections 107(5) and (5)(E) of the FCU Act.[26] Section 107(5) provides in relevant part that an FCU shall have *power to participate with* other credit unions, credit union organizations, or financial organizations in making loans to credit union members.[27] Section 107(5)(E) requires further that participation loans *with* other credit unions, credit union organizations, or financial organizations shall be in accordance with written policies of the credit union's board of directors, provided that a credit union which *originates* a loan for which participation arrangements are made in accordance with this subsection *shall retain an interest* of at least 10 per centum of the face amount of the loan.[28] While the statutory requirements of section 107(5)(E) primarily pertain to FCUs involved in loan participations, the Board chose, for safety and soundness reasons, to extend most of the requirements in § 701.22 to cover all FICUs as part of the 2013 Final Rule.[29]

In the 2013 Final Rule, the Board noted two specific safety and soundness concerns as reasons for adopting the current definition of ''originating lender,'' explaining in relevant part as follows:

The 2013 Final Rule requires an originating lender to remain part of the participation arrangement and to retain a continuing interest in the loan in order to be a true participant. Otherwise, the transaction is not a loan participation but more akin to the sale of an eligible obligation. As the Board noted in 1991, permitting the sale of participation interests in eligible obligations will *blur the distinction* between loan participations and loan purchases and

[22] Emphasis added.

[23] *See, e.g.,* NCUA Legal Op. 18–0133 (March 2018), *available at https://www.ncua.gov/regulation-supervision/legal-opinions/2018/loan-participations.*

[24] NCUA Legal Op. 15–0813 (Aug. 10, 2015) *available at https://www.ncua.gov/regulation-supervision/legal-opinions/2015/loan-participations-indirect-loans-originating-lenders.*

[25] 78 FR 37946, 37949 (June 25, 2013) (providing verbatim: The proposed rule revised the definitions of ''originating lender'' and ''loan participation'' to clarify that the originating lender must participate in the loan throughout the life of the loan.''); *see also* § 701.22(a) (providing in relevant part that: *Loan participation* means a loan where one or more eligible organizations participate pursuant to a written agreement *with the originating lender,* and the written agreement requires the originating lender's continuing participation throughout the life of the loan. (emphasis added)).

[26] *See* 76 FR 79548, 79549 (Dec. 22, 2011); *and* 78 FR 37946, 37949 (June 25, 2013) (providing that: The requirement that credit unions only participate with the originating lender derives from the FCU Act's requirement for originating FCUs to retain at least a 10 percent interest in the face amount of all loans they participate out. Moreover, the Board interprets the authority in the FCU Act for credit unions to participate in loans ''with'' other lenders to contemplate a shared, continuing lending arrangement. Simply put, the rule requires an originating lender to remain part of the participation arrangement and to retain a continuing interest in the loan in order to be a true participant. Otherwise, the transaction is not a loan participation but more akin to the sale of an eligible obligation.).

[27] 12 U.S.C. 1757(5) (emphasis added).

[28] Section 1757(5)(E) (emphasis added).

[29] *See* 76 FR 79548, 79548 (Dec. 22, 2011) (Explaining in part that: [L]oan participations [. . .] create more systemic risk to the share insurance fund (NCUSIF) due to the resulting interconnection between participants. For example, large volumes of participated loans in the system tied to a single originator, borrower, or industry or serviced by a single entity have the potential to impact multiple credit unions if a problem arises. Additionally, as both federal credit unions (FCUs) and federally insured state-chartered credit unions (FISCUs) actively engage in loan participations, it is important to the safety and soundness of the NCUSIF that all federally insured credit unions (FICUs) adhere to the same minimum standards for engaging in loan participations. The Board believes such standards are necessary to ensure the NCUSIF consistently recognizes and accounts for the risks associated with the purchase of loan participations. Finally, during examinations and other FICU contacts, the agency has encountered confusion concerning the application of the current loan participation rule regarding the entities and transactions subject to the rule.); *and* 78 FR 37946, 37947 & 37955 (June 25, 2013); *and* § 741.225.

sales, arguably circumventing the purpose of the loan participation and eligible obligations rules. Additionally, the Board believes the continued participation of the lender that initially originated the loan is integral to a safe and sound participation arrangement. In 1991, the Board expressed its concern that a lender may have a *decreased interest in properly underwriting a loan* if they know they can later reduce their risk by selling participation interests in it. The requirement for the originating lender's continued participation in a loan participation arrangement is intended to address this safety and soundness concern.[30]

As explained in more detail below, these concerns are fully accounted for under the 2015 Opinion and this proposal by limiting the interpretation to indirect loans and requiring that such loans meet the same general requirements applicable to indirect loans made by FCUs under current § 701.23(b)(4)(iv).

The 2013 Final Rule responded to concerns raised by commenters regarding the proposed definition of ''originating lender'' and its application in situations where a CUSO underwrites and processes a loan, but the FICU funds the loan. In response to this feedback the Board provided the following explanation.

These commenters observed that a CUSO often serves as an originator in name only and, thus, is not the most appropriate party to regard as the originating lender for the purposes of the rule. For example, loans may be *underwritten* and processed by a CUSO, but funded by its owner credit union. The Board acknowledged that this CUSO model is not uncommon within the industry and permissible under § 712.5. For purposes of this final rule, it was the Board's intent that the originating lender is the entity with which the borrower initially or originally contracts for the loan.[31]

As noted above, the Board's responses to commenters in the 2013 Final Rule regarding the definition of originating lender were limited to situations in which a FICU purchased a loan from a CUSO that had underwritten the loan. The Board did not discuss the application of the definition of originating lender to CUSOs or other entities in the context of indirect lending arrangements in which a purchasing FICU underwrites the loan and makes the final underwriting decision. Accordingly, the application of the definition of originating lender to CUSOs or other entities in the context of indirect lending arrangements was left unaddressed in the 2013 Final Rule and open to later interpretation by the NCUA, which is what it did two years later in the 2015 Opinion discussed in more detail in the following paragraphs.

The NCUA has long used the act of underwriting a loan as a feature to distinguish between transactions where a FICU makes a loan and transactions where a FICU purchases a loan.[32] In particular, in a 1997 legal opinion the NCUA explained:

FCUs may participate in indirect lending arrangements under the authority to *make loans to members,* 12 U.S.C. 107(5); 12 CFR 701.21, rather than the authority to purchase eligible obligations, 12 U.S.C. 107(13); 12 CFR 701.23, as long as two conditions are met. *First, the FCU must make the final underwriting decision.* That is, before the retailer and the member complete the loan or sales contract, the FCU must review the application and determine that the transaction conforms to its lending policies. This is because an FCU may not delegate its lending authority to a third party. Second, the retailer must assign the loan or sales contract to the FCU very soon after it is completed. Assignment close in time to the making of the loan allows the retailer to function as the facilitator of the loan while the FCU remains the true lender. As the time between completion and assignment of the loan lengthens, the FCU's payment to the retailer becomes the purchase of the loan rather than part of the processing of the loan.[33]

By requiring the purchasing credit union to make the final underwriting decision in an indirect lending transaction, the NCUA ensured that the purchasing credit union was not relying on the due diligence of the loan seller who might otherwise have had a decreased interest in properly underwriting the loan knowing it would later be sold. Moreover, under the NCUA's loan participation regulation, the originating lender is required to retain at least a 5-percent interest in any participation interest for the life of the loan.[34] Accordingly, where an eligible organization makes a loan through an indirect lending arrangement there is no greater risk of incentives for lax or improper underwriting for purposes of § 701.22 than if the eligible organization had processed and funded the loan itself.

Furthermore, as discussed in the 1997 legal opinion quoted above, the NCUA has long distinguished between indirect loans, made under section 107(5) of the FCU Act and 12 CFR 701.21, and eligible obligations purchased under section 107(13) of the FCU Act and 12 CFR 701.23.[35] For over 25 years the NCUA has treated indirect loans—as defined under current § 701.23(b)(4)(iv)—made by a credit union to be separate and distinct from eligible obligations. Accordingly, while permitting the sale of participation interests in eligible obligations might blur the distinction between loan participations and loan purchases and sales and circumvent the purpose of the loan participation and eligible obligations rules, allowing the sale of participation interests in indirect loans presents no such risk.

Working within the regulatory and interpretative history discussed above, the NCUA determined in the 2015 Opinion that an ''eligible organization'' [36] may be considered the ''originating lender'' for purposes of § 701.22 where the eligible organization generated the loan through an ''*indirect*

[30] 78 FR 37946, 37948 & 37949 (emphasis added) (providing also that: In granting [loan participation authority to FCUs], Congress expressed its intent to enhance the ability of FCUs to serve their members' loan demands. Congress also expressed, however, that originating FCUs must maintain discipline in the origination process. [. . . T]he loan participation authority must not be so broad that loan participations may be originated from any source. [. . .]); 56 FR 15034, 15034–15035 (April 15, 1991) (providing that: NCUA has interpreted the term ''participation loan'' to mean arrangements made prior to disbursements of the loan proceeds. In the preamble to the proposed rule, the Board stated that this interpretation may be too restrictive and proposed deleting it. [. . .] One commenter noted that this change will blur the distinction between loan participations and loan purchases and sales. [. . .] There are two basic safety and soundness concerns with the proposed change. FCUs may have a decreased interest in properly underwriting a loan if they know they can later reduce their risk by selling participation interests in it. Alternatively, FCUs interested in obtaining a participation after the loan is made may not properly investigate the loan and may instead rely on the original participants to have properly underwritten the loan. FCUs may jump in without a proper due diligence review. [. . .] Accordingly, the NCUA Board declines to adopt the proposed change and will continue to require a written commitment to participate in a loan precede final disbursement.); *see also* 68 FR 39866, 39867 (July 3, 2003); 68 FR 75110 (Dec. 30, 2003); *and* H.R. Rep. No. 95–23, at 12 (1977), *reprinted in* 1977 U.S.C.C.A.N. 115.

[31] 78 FR 37949–37950 (emphasis added).

[32] *See, e.g.,* NCUA Legal Op. 92–1203 (Jan. 5, 1993); NCUA Legal Op. 92–1203 (May 11, 1993); NCUA Legal Op. 97–0546 (Aug. 6, 1997), *available at https://ncua.gov/regulation-supervision/legal-opinions; and* § 701.23(b)(4)(iv).

[33] NCUA Legal Op. 97–0546 (emphasis added).

[34] § 701.22(d)(4)(ii) (''The interest that the originating lender will retain in the loan to be participated. If the originating lender is a federal credit union, the retained interest must be at least 10 percent of the outstanding balance of the loan through the life of the loan. If the originating lender is any other type of eligible organization, the retained interest must be at least 5 percent of the outstanding balance of the loan through the life of the loan, unless a higher percentage is required under state law.'').

[35] NCUA Legal Op. 97–0546.

[36] *Id.* (providing in relevant part as follows: ''*Eligible organization* means a credit union, credit union organization, or financial organization.'').

lending arrangement'' [37] with a retailer such as an auto dealer.[38] Current § 701.22(a) defines the term ''originating lender'' as ''the participant with which the borrower initially or originally contracts for a loan and who, thereafter or concurrently with the funding of the loan, sells participations to other lenders.'' [39] The 2015 Opinion explained that, in indirect lending arrangements with a retailer such as an auto dealer, the retailer is acting as an agent of the eligible organization, and is simply performing as an administrative functionary processing a loan for the eligible organization, and the retailer's activities are part and parcel of, and an extension of, the eligible organization's lending operations. In this context, the 2015 Opinion concluded, the retailer is not acting as a separate lender generating loans for itself and then selling those loans to an eligible organization. Rather, the retailer is a facilitator that is part of the eligible organization's loan processing mechanism, and the eligible organization is the *de facto* originating lender and, therefore, the originating lender for purposes of the NCUA's loan participation rule.

The 2015 Opinion explained further that a loan purchased by an eligible organization must satisfy two conditions to be classified as an ''indirect loan'' and not the purchase of a loan.[40] First, the eligible organization must make the final underwriting decision regarding the loan. In other words, a loan must be underwritten by the purchasing eligible organization before completion of the loan or sales contract.[41] An eligible organization may use an automated credit scoring system to make its final underwriting decision as long as the ''score'' obtained from the automated system is the sole determinant for granting credit.[42] When an eligible organization establishes the qualifying criteria for the automated scoring system, it is effectively making an advance decision on a particular application.[43] So long as the party entering the borrower's application information does not exercise any judgment regarding that information, the score will be deemed to reflect the FCU's lending policies.[44]

Second, the sales contract must be assigned to the eligible organization *very soon after* it is signed by the borrower and the dealer.[45] As explained in a separate NCUA legal opinion, assignment close in time to the making of the loan allows the retailer to function as the facilitator of the loan while the eligible organization remains the true lender.[46] The length of time that satisfies ''very soon after'' depends on the nature of the loan and the practical realities of assigning certain kinds of loans in the current marketplace and in accordance with prevailing industry standards.[47] While ''very soon after'' is generally determined on a case-by-case basis by loan type and in accordance with commercial reasonableness, the longer the time between the formation of the contract and its assignment, the more likely the program will be viewed as involving the purchase of an eligible obligation rather than the making of a loan.[48]

The Board believes that codifying the 2015 Opinion will clarify the loan participations rule and facilitate further growth in credit unions' purchase and sale of indirect loan participations. Industry data shows significant growth in credit unions engaging in indirect lending programs, which have become an important channel for credit unions to extend services to their members and provide a viable source of income to support their growth.

Since 2015, FICUs have experienced large growth in indirect lending programs as reflected in Table 1. The $299 billion outstanding balance of indirect loans as of June 30, 2022, more than doubled the 2015 year-end loan balance.[49]

During the past seven years, FICUs' indirect lending activities had double-digit increases (ranging from 14 percent to 21 percent) year over year between 2016 and 2018, and a low single-digit increase in 2019 and 2020.[50] The speed of growth went back to double digits in 2021, with FICUs reporting an aggregate 16.26 percent increase as of June 30, 2022, from year-end 2021.[51] The share of indirect loans outstanding in FICUs' total loan portfolio increased from 17.35 percent in 2015 to 21.22 percent in 2018, and reached 21.56 percent as of June 30, 2022, after maintaining at 20 percent for the past three years.[52]

Furthermore, between December 31, 2015, and June 30, 2022, the delinquency rate on the indirect lending program was relatively stable, ranging from 0.77 percent to 0.47 percent, while the net charge-off percent decreased from 0.7 percent in 2017 to 0.24 percent in 2021 and 0.21 percent in June 2022.[53]

TABLE 1—FICU INDIRECT LENDING ACTIVITIES [54]

(In $ million)	2015	2016	2017	2018	2019	2020	2021	2022 [55]
Total Outstanding Indirect Loans	136,583	165,171	194,016	221,477	228,559	233,161	257,271	299,106
% Year over Year Growth	....	20.93	17.46	14.15	3.20	2.01	10.34	16.26

[37] *See* § 701.23(b)(4)(iv) (''An *indirect lending* or indirect leasing *arrangement* that is classified as a loan and not the purchase of an eligible obligation because the Federal credit union makes the final underwriting decision and the sales or lease contract is assigned to the Federal credit union very soon after it is signed by the member and the dealer or leasing company.'') (emphasis added).

[38] NCUA Legal Op. 15–0813.

[39] *Id.* (providing in relevant part: ''*Originating lender* means the participant with which the borrower initially or originally contracts for a loan and who, thereafter or concurrently with the funding of the loan, sells participations to other lenders.'').

[40] *See* § 701.22(b)(4)(iv); *see also* NCUA Legal Op. 15–0813; *and* 78 FR 37946, 37949 (explaining that ''a lender 'may have a decreased interest in *properly underwriting a loan* if they know they can later reduce their risk by selling participation interests in it.' '').

[41] *See id.*

[42] *See* NCUA Legal Op. 97–0546.

[43] *See id.*

[44] *See id.*

[45] Emphasis added.

[46] *See* NCUA Legal Op. 97–0546.

[47] The preamble to the 1998 proposal to amend the eligible obligations rule requested public comment on whether the NCUA should specify a certain number of days as constituting ''very soon.'' 63 FR 41976, 41977 (Aug. 6, 1998). After considering the comments, however, the NCUA Board determined not to specifically define it because it wanted to provide FCUs with flexibility under various circumstances. The NCUA Board also clarified that assignment of the loan means acceptance of the loan and not necessarily the physical receipt of the loan documentation, recognizing that acceptance and payment are often done electronically. However, physical receipt of the loan documents by the FCU should occur within a reasonable time following acceptance of the loan. 63 FR 70997, 70998 (Dec. 23, 1998); *see also* NCUA Legal Op. 97–0546 (Aug. 6, 1997) (Concluding that an indirect lending arrangement where the retailer made a loan and assigned it to the purchasing credit union within one business day met the ''very soon after'' timing requirement.).

[48] 63 FR 41976, 41977 (Aug. 6, 1998).

[49] NCUA call report data for all federal insured credit unions from the 4th quarter of 2015 through the 2nd quarter of 2022.

[50] NCUA call report data for all federally insured credit unions from the 4th quarter of 2015 through the 4th quarter of 2021.

[51] NCUA Call Report data for all federally insured credit unions from the 4th quarter of 2015 through the 2nd quarter of 2022.

[52] *Id.*

[53] *Id.*

[54] *Id.*

[55] Period as of June 30, all other periods were as of December 31.

TABLE 1—FICU INDIRECT LENDING ACTIVITIES [54]—Continued

(In $ million)	2015	2016	2017	2018	2019	2020	2021	2022 [55]
% Indirect Loans Outstanding/Total Loans	17.35	19.00	20.27	21.22	20.63	20.05	20.50	21.56
Total Del. Indirect Loans (> = 60 Days)	988	1,264	1,391	1,494	1,513	1,291	1,198	1,537
% Loans Delinquent > = 60 Days/Total Indirect Loans	0.72	0.77	0.72	0.67	0.66	0.55	0.47	0.51
Net Indirect Loan Charge-Offs	782	997	1,264	1,318	1,354	1,129	594	288
% Net Charge-Offs/Avg Indirect Loans	0.63	0.66	0.70	0.63	0.60	0.49	0.24	0.21

For the reasons discussed previously, and consistent with sections 107(5) and 107(5)(E) of the FCU Act and the 2015 Opinion, the Board is proposing to codify into the NCUA's regulations its interpretation that an eligible organization may be considered an ''originating lender'' for purposes of § 701.22 where the eligible organization generates a loan through an indirect lending arrangement. Moreover, the Board proposes to further clarify in the regulation that any ''eligible organization''—as that term is defined under § 701.22(a)—that acquires a loan through an indirect lending arrangement acts as the originating lender for purposes of § 701.22, provided the eligible organization made the final underwriting decision regarding making the loan and was assigned the loan or sales contract very soon after the inception of the obligation to extend credit. In such cases, the Board considers the third party processing the loan to be an agent of the eligible organization that performs as an administrative functionary processing the loan for the eligible organization, and the third party's activities are part and parcel, and an extension, of the eligible organization's lending operations.

Where an indirect loan is underwritten by the purchasing eligible organization before the loan is made and the loan is transferred to the eligible organization very soon after the inception of the obligation to extend credit, the Board believes there is little risk the loan will not be properly underwritten. Accordingly, proposed § 701.22(a) would add to the end of the definition of ''originating lender'' a second clarifying sentence providing that originating lender includes a participant that acquires a loan through an indirect lending arrangement as defined under § 701.21(c)(9). Proposed paragraph (c)(9) provides, in part, that *indirect lending arrangement* means a written agreement to purchase loans from the loan originator where the purchaser makes the final underwriting decision regarding making the loan, and the loan is assigned to the purchaser very soon after the inception of the obligation to extend credit.

The Board specifically requests comment on whether there are certain types of transactions that should be excluded from the interpretation above. In particular, are there transactions in which eligible organizations acquire loans through indirect lending arrangements, but the third parties making the loans do *not* act as administrative functionaries processing the loan on behalf of the eligible organizations, and the third parties' activities are *not* part and parcel, and an extension, of the eligible organizations' lending operations? If there are transactions of this type, please explain why they should be excluded and provide information about the transactions and the specific activities undertaken by the parties.

In addition, the Board requests comment on whether there are other factors, changes, safety and soundness, or compliance implications the NCUA should consider related to the proposed amendments to the definition of ''originating lender.'' If there are, please explain them in detail and provide supporting data and information. Should the Board consider providing additional clarity such as adding some parameters around the meaning of ''very soon after'' for the assignment of the loan or contract to the credit union? Examples could be within seven days of the borrower executing the loan or contract, or assignment prior to the first loan payment.

The Board also invites comments on what it means for the credit union to make the final underwriting decision regarding making the loan in an indirect lending arrangement. For example, should the Board specify in the rule that a credit union in an indirect lending arrangement must be involved or consulted at the time of the extension of credit? Or, can the credit union simply provide its underwriting standards to the other party in the indirect lending arrangement and clarify in the indirect lending agreement that only those loans meeting the credit union's underwriting standards will be accepted for funding? Would a credit union still be making the final underwriting decision if a third party includes significantly more underwriting criteria that are more restrictive, for example, than the credit union requires?

Also, should the Board establish an indirect lending rule? And if so, what specifically should the Board consider in any future indirect lending rulemaking? Should a credit union be considered the originating lender in cases where an intermediary is added to a loan transaction between the initial party extending credit and a credit union, including a third party facilitating the loan transaction? The NCUA received several inquiries from the credit union system related to CUSOs that work with other lenders to extend credit. The CUSOs in those cases then either receive an immediate assignment of the loans and/or act as a facilitator in immediately assigning loans further to credit unions, where the loans meet the credit unions' underwriting criteria.

Are there structural, safety and soundness, or compliance concerns that would warrant considering that the addition of intermediaries in loan origination transactions, including CUSOs, precludes a credit union assignee from being considered the originating lender under the revised definition in the proposed rule?

Are there any additional safety and soundness or compliance implications concerning the proposed definition of ''originating lender'' that the Board should consider?

Should the Board consider defining the term ''an investment in a pool of loans'' in a future rulemaking? If so, how should it be defined and why?

Section 701.22(e) Temporary Regulatory Relief in Response to COVID–19

Current § 701.22(e) provides that notwithstanding paragraph (b)(5)(ii) of § 701.22, during the period commencing on April 21, 2020, and *concluding on December 31, 2022,* the aggregate amount of loan participations that may be purchased from any one originating lender shall not exceed the greater of $5,000,000 or 200 percent of the FICU's net worth.[56] The Board approved § 701.22(e) to help ensure that FICUs remained operational and had sufficient

[56] Emphasis added.

liquidity during the COVID–19 pandemic.[57] The Board concluded, at the time, that the amendments would provide FICUs with the necessary flexibility in a manner consistent with the NCUA's responsibility to maintain the safety and soundness of the credit union system.[58] As provided in current paragraph (e), the temporary regulatory relief provided under the paragraph will expire on December 31, 2022. Accordingly, the Board is proposing to remove this paragraph as part of any final rule amending § 701.22 issued after December 31, 2022.

The Board welcomes comments on the impact, if any, that was experienced due to the flexibilities provided in the temporary rule. Did the temporary rule have any effect on the participation markets? Are there any safety and soundness or compliance implications related to the expiration of the flexibilities?

Finally, the Board invites comment on what other recommendations it should consider in the loan participation rule. For example, should the Board consider replacing prescriptive limits with principles-based requirements? Should the Board consider removing the limit on the amount of loan participations that could be purchased from any one originating lender under current § 701.22(b)(5)(ii)?

Section 701.23 Purchase, Sale, and Pledge of Loans

As discussed in more detail in this portion of the preamble, this proposal would make several changes to current § 701.23 of the NCUA's regulations. These changes are intended to clarify numerous provisions regarding the purchase, sale, and pledge of eligible obligations. The proposal would also amend the NCUA's current regulatory requirements under current § 701.23 to provide FCUs expanded authority and autonomy to innovate and transact business with fintech companies and other institutions that provide services associated with the origination and sale of loans made to members of FCUs.

Section 701.23 Introductory Paragraph

The introductory paragraph to current § 701.23 sets forth the scope and limitations of the section. The Board added the introductory paragraph to § 701.23 as part of the 2013 Final Rule.[59] The introductory paragraph was added to clarify several issues related to the scope and applicability of § 701.23. In particular, the 2013 Final Rule explained in five sentences as follows: The proposal added introductory text to § 701.23 to clarify the scope of § 701.23 and to distinguish transactions under § 701.23 from transactions covered by § 701.22. The final rule adopts the additional language substantially as proposed, but with some amendments to conform it to a 2012 final rule promulgated by NCUA eliminating the Regulatory Flexibility Program (RegFlex).[60] The final rule regarding RegFlex provides a limited exception to the general requirement that an FCU's purchase, sale, or pledge of all or part of a loan must be to one of its own members.[61] Specifically, the exception permits FCUs that meet the well capitalized standard to buy loans from other FICUs without regard to whether the loans are eligible obligations of the purchasing FCU's members or the members of a liquidating credit union. The final rule also makes a parallel conforming amendment to the introductory text to § 701.22 in this regard.[62]

The introductory paragraph to current § 701.23 has three separate substantive provisions. First, the paragraph provides that the section governs an FCU's purchase, sale, or pledge of all or part of a loan to one of its own members where no continuing contractual obligation is contemplated between the seller and the purchaser. The first provision also notes that there is a limited exception to the membership requirement for certain well-capitalized FCUs. Second, the paragraph elaborates on the membership requirement by providing that the borrower must be a member of the purchasing FCU *before* the purchase is made, except as provided in current § 701.23(b)(2). Third, the paragraph provides broadly that an FCU may not purchase a non-member loan to hold in its portfolio.

Since amending § 701.23 as part of the 2013 Final Rule, the NCUA has received numerous inquiries from NCUA examiners, FCUs, fintech companies, and other parties who have expressed confusion about how to interpret these provisions. This confusion has led to inconsistent reporting of loan interests by FCUs and uncertainty regarding which of the two sections, § 701.22 or § 701.23, applies to certain transactions, particularly innovative programs that have been designed by FICUs after 2013. In addition, the Board is concerned that continued confusion about when a borrower is required to be a member under § 701.23 could discourage FCUs from entering into certain safe and sound loan purchase, sale, and pledge agreements that are within their statutory authority.

The clause in the first sentence of the introductory paragraph to current § 701.23 that provides ''where no continuing contractual obligation between the seller and purchaser is contemplated'' continues to be a source of confusion for examiners and the credit union system. As mentioned above, in practice loan purchase agreements, regardless of whether the transactions involve the purchase of an eligible obligation or a loan participation, frequently contain some form of continuing contractual obligation between the buyer and the seller, including representations and warranties regarding the loans and loan repurchase agreements, servicing agreements, and other similar types of ongoing obligations. Accordingly, the Board requests comments on deleting the continuing contractual obligations clause in current § 701.23. The Board intends this potential change to work in conjunction with the proposed changes to the introductory paragraph to current § 701.22.

In the introductory paragraph to § 701.23, the Board is considering two other changes in conjunction with amendments made elsewhere in this proposal, which are described in more detail below. First, the Board requests comments on removing the clause referring to the limited exception for well-capitalized FCUs. As discussed in more detail below in the part of the preamble on § 701.23(b)(2), the Board is proposing to remove the well-capitalized requirements for FCU purchases of certain non-member loans from FICUs. Accordingly, the Board believes that deleting the clause referring to the limited exception for well-capitalized FCUs is a necessary conforming amendment.

Second, the Board is proposing to remove the third sentence in the introductory paragraph to current § 701.23 to clarify the broad prohibition on holding non-member loans in the portfolio. This prohibition appears to have originally been intended to address FCU purchases of non-member loans to complete pools of loans for resale, as authorized for real estate-secured loans and federally guaranteed student loans under current § 701.23(b)(1)(iii) and (iv). The prohibition on retaining the non-member loans in portfolio goes together with the authority in paragraphs (b)(1)(iii) and (iv) because those provisions allow an FCU to buy such

[57] *See* 85 FR 22010 (April 21, 2020); 85 FR 83405 (Dec. 22, 2020) (extending paragraph (e) through Dec. 31, 2021); *and* 86 FR 72517 (Dec. 22, 2021) (extending paragraph (e) through Dec. 31, 2022).

[58] 85 FR 22010, 22010 (April 21, 2020).

[59] 78 FR 37946 (June 25, 2013).

[60] 77 FR 31981 (May 31, 2012).

[61] 12 CFR 701.23(b)(2).

[62] 78 FR 37954–37955.

non-member loans solely to complete a pool of loans for resale.

Moreover, the second sentence in current § 701.23(b)(1)(iv) further confirms this relationship by providing that a pool must include a substantial portion of the credit union's members' loans *and must be sold promptly*.[63] For other purchases of non-member loans under current § 701.23, the authority is not tied to a plan or requirement to resell the loans being purchased. Prohibiting the FCU from retaining the loans in portfolio, as the current wording in the undesignated introductory paragraph implies, unnecessarily restricts FCUs' authority to purchase and hold non-member loans from FICUs under current § 701.23(b)(1)(ii)[64] and (b)(2). Accordingly, the Board requests comment on deleting the third sentence in the introductory paragraph to § 701.23, providing that an FCU may not purchase a non-member loan to hold in its portfolio.

The Board is considering one other change to the introductory paragraph. The second paragraph provides that for purchases of eligible obligations, except as described in paragraph (b)(2) of the section, the borrower must be a member of the purchasing FCU before the purchase is made. As discussed above, there are express exceptions to the membership requirement under paragraph (b)(1) as well as in paragraph (b)(2). For example, paragraphs (b)(1)(iii) and (iv) authorize FCUs to buy non-member loans to complete a pool of loans for resale. Accordingly, the Board requests comment on amending the second sentence in the introductory paragraph to current § 701.23 to provide that for purchases of eligible obligations, except as described under paragraph (b) of the section, the borrower must be a member of the purchasing FCU before the purchase is made.

If the changes proposed above are adopted in a final rule, the introductory text of § 701.23 would provide that the section governs an FCU's purchase, sale, or pledge of all or part of a loan to one of its own members, subject to certain exceptions. The introductory paragraph would provide further that for purchases of eligible obligations, except as otherwise described under paragraph (b) of § 701.23, the borrower must be a member of the purchasing FCU before the purchase is made.

Section 701.23(a) Definitions

The proposed rule would, among other changes discussed below, amend current § 701.23(a) to add the heading ''Definitions'' to the paragraph and remove the numbering from the individual definitions under paragraph (a). This change is intended to avoid errors and confusion when definitions in paragraph (a), which may be cross referenced elsewhere in the NCUA's regulations, are added or removed. Accordingly, the individual definitions included under proposed § 701.23(a) will be listed in alphabetic order but will not be numbered individually.

Eligible obligation. Proposed § 701.23(a) would amend the definition of ''eligible obligation'' to clearly distinguish between an eligible obligation and a note held by a liquidating credit union. Current § 701.23(a) defines the term eligible obligation broadly to mean a loan or group of loans, which includes the notes of a liquidating credit union.[65] As explained in the part of the preamble on § 701.23(b)(4), under this proposal the statutory 5-percent limitation on the aggregate of the unpaid balance of notes purchased under § 701.23 would apply to only notes of liquidating credit unions and not to eligible obligations as that term is generally used under section 107(13)[66] of the FCU Act. Accordingly, the proposal would amend the current definition of eligible obligation to clarify that the term does not include a note held by a liquidating credit union.

The proposal would also amend the definition of ''eligible obligation'' to clarify that the term includes a whole loan or part of a loan. The NCUA has long held the position that the term eligible obligation includes loans, in whole or in part, provided the loan does not meet the definition of a loan participation under § 701.22(a).[67] The Board believes that the amended definition of an eligible obligation would provide clarity and reduce confusion in the credit union system concerning when a transaction involving a loan purchased in part (partial loan) meets the regulatory definition of an eligible obligation. It has come to the Board's attention that many credit union officials find the eligible obligations rule unclear, specifically when attempting to determine which rule applies to a loan purchased in part. The amended definition will allow FCU officials to differentiate between a transaction involving a partial loan that meets the definition of an eligible obligation under § 701.23 and a transaction involving a partial loan that meets the definition of a loan participation under § 701.22.

Current § 701.22(a) provides that loan participation means a loan where one or more eligible organizations participate pursuant to a written agreement with the originating lender, and the written agreement requires the originating lender's continuing participation throughout the life of the loan. For example, if an FCU purchases a partial loan that does not meet the definition of loan participation under proposed § 701.22(a), then the transaction may still be permissible provided it meets the definition of an ''eligible obligation'' under proposed § 701.23(a) and meets the requirements under that section.

Finally, the proposal would amend the definition of ''eligible obligation'' to remove the words ''group of loans.'' The words are redundant because the term eligible obligation is used in its plural form, eligible obligations, throughout proposed and current § 701.23 to indicate where the section authorizes or applies to the purchase of one or more loans. The Board believes removing the phrase ''group of loans,'' in conjunction with the other changes discussed in this proposal, will clarify the definition of eligible obligation. Accordingly, for all the reasons discussed above, proposed § 701.23(a) would provide that *eligible*

[63] Emphasis added.

[64] Authorizing FCUs to purchase eligible obligations of a liquidating credit union's individual members, from the liquidating credit union.

[65] *See, e.g.,* §§ 701.23(b)(1)(ii), (b)(2)(ii), and (b)(4).

[66] Section 1757(13) (authorizing FCUs by providing that: [I]n accordance with rules and regulations prescribed by the Board, to purchase, sell, pledge, or discount or otherwise receive or dispose of, in whole or in part, any eligible obligations (as defined by the Board) of its members and to purchase from any liquidating credit union notes made by individual members of the liquidating credit union at such prices as may be agreed upon by the board of directors of the liquidating credit union and the board of directors of the purchasing credit union, but no purchase may be made under authority of this paragraph if, upon the making of that purchase, the aggregate of the unpaid balances of notes purchased under authority of this paragraph would exceed 5 per centum of the unimpaired capital and surplus of the credit union[.]).

[67] *See* 78 FR 37946, 37948 (June 25, 2013) (providing in part: ''[The introductory paragraph to § 701.22] clarifies that the [section] applies to a natural person FICU's purchase of a loan participation where the borrower is not a member of that credit union. Generally, an FCU's purchase, in whole or in part, of its member's loan is covered by NCUA's eligible obligations rule at § 701.23.'' The 2013 final rule also notes in FN 2 that there is also ''a limited exception for certain well capitalized federal credit unions to purchase, subject to certain conditions, non-member eligible obligations from a FICU. 12 CFR 701.23(b)(2).''); *see also,* 12 U.S.C. 1757(13) (providing in part: An FCU shall have power, ''in accordance with rules and regulations prescribed by the Board, to purchase, sell, pledge, or discount or otherwise receive or dispose of, *in whole or in part,* any eligible obligations (as defined by the Board) of its members.'' (emphasis added)).

obligation means a whole loan or part of a loan (other than a note held by a liquidating credit union) that does not meet the definition of a loan participation under § 701.22(a).

Liquidating credit union. Proposed § 701.23(a) would define the term ''liquidating credit union'' to specify the point in time when a credit union meets the definition of a liquidating credit union for purposes of applying the 5-percent limitation in proposed § 701.23(b)(4). The term liquidating credit union is used but not defined in current § 701.23 because the section does not distinguish between eligible obligations and notes of liquidating credit unions for purposes of calculating the 5-percent limitation on the aggregate of the unpaid balance of loans purchased under current § 701.23(b)(1) and (b)(2)(ii). As explained in more detail later in the part of the preamble on proposed § 701.23(b)(4), under this proposal, the 5-percent limitation would apply only to notes purchased from liquidating credit unions, making it necessary for the NCUA to specify the point in time when a credit union meets the definition of a liquidating credit union. Consistent with Congress' use of the broad term ''credit union'' in section 107(13) of the FCU Act, the definition of liquidating credit union would include both liquidating FICUs and liquidating credit unions not insured by the NCUA.[68]

Accordingly, the Board proposes to define the term liquidating credit union as follows: Liquidating credit union means: (1) in the case of a voluntary liquidation, a credit union is a liquidating credit union as of the date the members vote to approve liquidation; and (2) in the case of an involuntary liquidation, a credit union is a liquidating credit union as of the date the board of directors is served an order of liquidation issued by either the NCUA or the state supervisory authority.

The Board specifically requests comment on whether the Board should provide any additional clarity regarding the definitions of the terms ''eligible obligation'' and ''loan participation.'' If so, what further clarification should be provided?

Also, should the Board consider defining the term ''empowered to grant'' in a future rulemaking? Are there any other terms used in § 701.23 that the Board should consider defining or further clarifying through a future rulemaking?

Section 701.23(b) Purchase of Loans

Current § 701.23(b) would be amended, as discussed in more detail later in this preamble, to make certain substantive changes and to implement clarifying and conforming changes. Proposed § 701.23(b) would amend the current paragraph heading to current paragraph (b) to clarify which transactions are covered under the paragraph. The current heading for paragraph (b) is ''Purchase.'' The Board believes that this would result in only a minor technical change to current § 701.23(b). The amended rule would only add the two words ''of loans'' to the current rule text to better clarify the type of eligible obligation transactions for which this section would apply, that being the purchase of loans. Accordingly, the paragraph heading for proposed § 701.23(b) would be revised to read ''Purchase of loans.''

Section 701.23(b)(1)

Section 701.23(b)(1)(ii)

Current § 701.23(b)(1)(ii) authorizes FCUs to purchase certain eligible obligations of a liquidating credit union's individual members from the liquidating credit union. As explained previously in the part of the preamble on § 701.23(a) regarding the definition of eligible obligation, under this proposal, notes of liquidating credit unions would no longer be included within the definition of ''eligible obligations.'' Accordingly, subject to the 5-percent limitation, this proposal would amend current § 701.23(b)(1)(ii) to remove the references to eligible obligations and authorize FCUs to purchase notes of a liquidating credit union's individual members from the liquidating credit union.

Section 701.23(b)(1)(iv)

The word ''mortgage'' is misspelled in the first sentence of current § 701.23(b)(1)(iv). Proposed § 701.23(b)(1)(iv) would revise the current rule to correct that misspelling. No substantive changes would be made to current paragraph (b)(1)(iv).

Section 701.23(b)(2) Purchase of Obligations From a FICU

Proposed § 701.23(b)(2) would revise the current rule to remove the CAMELS rating requirement and the capital classification requirements in the introductory paragraph. Current § 701.23(b)(2) provides that an FCU that received a composite CAMELS rating of ''1'' or ''2'' for the last two (2) full examinations and maintained a capital classification of ''well capitalized'' under part 702 of the chapter for the six (6) immediately preceding quarters may purchase and hold certain obligations, provided that it would be empowered to grant them.

The Board is proposing to simplify the rule and provide FCUs additional authority to purchase loans. This includes removing limits on eligible obligations of a credit union's members and removing the CAMELS rating and capital classification requirements.

The CAMELS rating and capital classification requirements were added to the NCUA's regulations as part of a 2001 final rule regarding the NCUA's RegFlex program.[69] The 2001 final rule explained, in two sentences responding to commenters suggestions that the requirements be removed, as follows: The Board continues to believe that CAMEL ratings and net worth ratios are the best measures of how well a credit union is managed and how much risk it presents to the NCUSIF and the credit union system. That is, consistent with safety and soundness concerns, credit unions with advanced levels of net worth and consistently strong supervisory examination ratings have earned exemptions from certain NCUA Regulations.[70]

FCUs have generally managed their loan purchase, sale, and pledge activity well since the addition of the CAMELS and capital requirements and continue to do so. Approximately 10 percent of FCUs were engaged in the purchase, sale, or pledge of loans during the first half of 2022.[71]

Additionally, the Board notes that this purchase authority is limited to only purchases from a FICU. Therefore, the loans able to be purchased under this authority are already in the credit union system. Moving the obligation from one FICU to another FICU generally is not expected to result in a significant increase to the Share Insurance Fund's risk exposure.

Further, the current CAMELS and net worth restrictions are only applicable to a limited segment of the credit union system given that the vast majority of FCUs have a CAMELS composite rating

[68] *See* Section 1757(13) (providing in relevant part: ''to purchase from any liquidating *credit union* notes made by individual members of the liquidating *credit union* at such prices as may be agreed upon by the board of directors of the liquidating *credit union* and the board of directors of the purchasing credit union, but no purchase may be made under authority of this paragraph if, upon the making of that purchase, the aggregate of the unpaid balances of notes purchased under authority of this paragraph would exceed 5 per centum of the unimpaired capital and surplus of the credit union;'' (emphasis added).).

[69] 66 FR 58656 (Nov. 23, 2001).

[70] 66 FR 58656.

[71] NCUA Call Report data for all FCUs as of the 2nd quarter of 2022.

of 1 or 2 and are well-capitalized.[72] Expansion of this authority would allow slightly more FCUs to purchase obligations from a FICU, potentially creating additional revenue and capital for the purchaser and providing an additional outlet for selling FICUs, creating additional liquidity channels in the credit union system.

Lastly, the NCUA believes any increased risk associated with removing the CAMELS rating and capital classification requirements in current § 701.23 would also be minimized by the addition of the proposed principles-based due diligence, risk assessment, and risk management requirements.

Accordingly, the introductory paragraph to proposed § 701.23(b)(2) would provide that an FCU may purchase and hold certain obligations if it would be empowered to grant them.

Section 701.23(b)(2)(ii) Notes of a Liquidating Credit Union

Current § 701.23(b)(2)(ii) authorizes FCUs to purchase certain eligible obligations of a liquidating credit union without regard to whether they are obligations of the liquidating credit union's individual members. As explained earlier in the part of the preamble on § 701.23(a) regarding the definition of eligible obligation, under this proposal notes of liquidating credit unions would no longer be included within the definition of ''eligible obligation.'' Accordingly, this proposal would amend current § 701.23(b)(2)(ii) to remove the words ''eligible obligations'' and ''obligations'' and authorize FCUs to purchase notes of a liquidating credit union without regard to whether they are notes of the liquidating credit union's individual members.

Section 701.23(b)(3) Introductory Text and (b)(3)(ii)

Proposed § 701.23(b)(3)(ii) would revise the current requirement that written agreements and schedules of loans be retained by the purchaser. Current § 701.23(b)(3)(ii) provides that a written agreement and a schedule of the eligible obligations covered by the agreement are retained in the purchaser's office. Under the proposed rule, the purchasing FCU would still be required to retain the written loan purchase agreement and a schedule of the eligible obligations covered by the agreement, but the proposal would eliminate the requirement for it to be retained in the purchaser's office.

The Board acknowledges the requirement for the FCU to retain the written loan purchase agreement and schedule of the eligible obligations in the purchaser's office could imply that the written loan purchase agreement and schedule be retained in a hard-copy format, which is outdated given the current digital environment. An FCU might choose to store its records in electronic format, in the cloud, or housed in off-site servers or databases. The Board intends, with this proposed change, that the FCU make the written loan purchase agreement and schedule of the eligible obligations covered by the agreement available upon request.[73] Credit unions that have some or all of their records maintained by an off-site data processor are considered to be in compliance for the storage of those records if the service agreement specifies the data processor safeguards against the simultaneous destruction of production and back-up information.[74] Accordingly, proposed § 701.23(b)(3)(ii) would provide that a written agreement and a schedule of the eligible obligations covered by the agreement are retained by the purchaser.

This proposed change would align this requirement with the NCUA's regulations and guidelines for FICUs on records preservation programs. Under part 749, the NCUA does not require or recommend a particular format for record retention. If the credit union stores records on microfilm, microfiche, or in an electronic format, the stored records must be accurate, reproducible, and accessible to an NCUA examiner.[75] If records are stored on the credit union premises, they should be immediately accessible upon the examiner's request; if records are stored by a third party or off site, then they should be made available to the examiner within a reasonable time after the examiner's request. The credit union must maintain the necessary equipment or software to permit an examiner to review and reproduce stored records upon request. The credit union should also ensure that the reproduction is acceptable for submission as evidence in a legal proceeding.[76]

Section 701.23(b)(4)

This proposal would amend current § 701.23(b)(4), which limits the aggregate unpaid balance of certain eligible obligations purchased by an FCU to a maximum of 5 percent of the FCU's unimpaired capital and surplus. Under this proposed rule, the 5-percent limitation would apply solely to notes of a liquidating credit union's members purchased by an FCU from the liquidating credit union. As discussed in the following paragraphs, the Board has determined this change would remove a regulatory limit to the purchase of eligible obligations that the FCU Act does not require. The Board believes adequate safety and soundness of eligible obligations purchases can be accomplished through principles-based regulation rather than a once-size-fits-all limitation.

Section 701.23 provides both the regulatory authority for purchases of eligible obligations by an FCU and the limitations. Currently, the 5-percent limitation applies to eligible obligations purchased by an FCU under § 701.23(b)(1) and (b)(2)(ii). In general, paragraph (b)(1) authorizes an FCU to purchase (1) eligible obligations of its members; (2) eligible obligations of a liquidating credit union's members from the liquidating credit union; and (3) student loans and real estate-secured loans from any source to facilitate the purchasing FCU's packaging of a pool of such loans to be sold or pledged on the secondary market. Paragraph (b)(2)(ii), which is on purchases from FICUs, authorizes an FCU to purchase the ''eligible obligations of a liquidating credit union without regard to whether they are obligations of the liquidating credit union's members.''

The statutory source of the 5-percent limitation is section 107(13) of the FCU Act.[77] Section 107 generally enumerates the powers of FCUs, and paragraph (13) authorizes an FCU to make certain loan purchases. Specifically, paragraph (13) provides verbatim as follows: in accordance with rules and regulations prescribed by the Board, to purchase, sell, pledge, or discount or otherwise receive or dispose of, in whole or in part, any eligible obligations (as defined by the Board) of its members and to purchase from any liquidating credit union *notes* made by individual members of the liquidating credit union at such prices as may be agreed upon by the board of directors of the liquidating credit union and the board of directors of the purchasing credit union, but no purchase may be made under authority

[72] As of June 30, 2022, 78 percent of FCUs were rated a CAMELS composite 1 or 2 and were classified as ''well capitalized.'' These FCUs account for 96 percent of total FCU assets. There were only 614 FCUs with a CAMELS composite rating of 3, 4, or 5, and only 166 FCUs not classified as ''well capitalized.''

[73] *See* § 749.2.

[74] *See* appendix A to part 749.

[75] *See* 12 CFR 749.5.

[76] *See generally* part 749; *and* NCUA Legal Op. 07–0812 (Jan. 2008), *available at https://www.ncua.gov/regulation-supervision/legal-opinions/2008/electronic-retention-records.*

[77] 12 U.S.C. 1757(13).

of this paragraph if, upon the making of that purchase, the aggregate of the unpaid balances of *notes* purchased under authority of this paragraph would exceed 5 per centum of the unimpaired capital and surplus of the credit union.[78]

Section 107(13) applies to the purchase of two mutually exclusive categories of loans—''eligible obligations'' (as that term may be defined by the Board) of the purchasing FCU's members and the ''notes'' of a liquidating credit union made to the liquidating credit union's members. The 5-percent limitation, however, applies solely to the second category of loans, that is, the notes of a liquidating credit union to its members. The statutory language specifies that ''no purchase may be made . . . if, upon the making of that purchase, the aggregate of the unpaid balances of *notes* purchased under authority of this paragraph would exceed 5 per centum of the unimpaired capital and surplus of the credit union.'' [79] The 5-percent limitation is specific to the ''aggregate unpaid balances of *notes*'' [80] purchased ''under authority of this paragraph'' (that is, paragraph (13) of section 107). As italicized in the preceding quotes, the only notes authorized to be purchased pursuant to section 107(13) are those of a liquidating credit union to its members. Notwithstanding the ambiguity introduced by the reference to the entire ''paragraph'' (13) in the context of the 5-percent limitation, the following term ''notes'' narrows the required scope of its application to purchases from a liquidating credit union.

Despite the statutory wording, the NCUA's implementing regulation at 12 CFR 701.23 does not distinguish between eligible obligations and notes. Section 107(13) of the FCU Act empowers the NCUA to define the term ''eligible obligation.'' The NCUA has exercised this discretion by opting to jointly treat notes and other eligible obligations as the same type of instrument under its regulations. Both are encompassed in the regulatory definition of the term ''eligible obligation,'' which is defined to be ''a loan or group of loans.'' [81] The proposed rule would amend current § 701.23 to more closely follow the statutory language. Under the proposed rule, the 5-percent limitation would apply solely to the purchase by an FCU of the notes made by a liquidating credit union to the liquidating credit union's members. The limitation would not apply to other loans purchased by an FCU under the authority of section 107(13).

The proposed rule would also amend the definition of ''eligible obligations'' to reflect the revised scope of the 5-percent limitation. Under the proposed rule, the term ''eligible obligation'' would be revised to mean ''a whole loan or part of a loan (other than a note held by a liquidating credit union) that does not meet the definition of a loan participation under § 701.22(a).'' [82]

The Board acknowledges that the current scope of the 5-percent limitation reflects or implies an alternate legal reading of the statutory language, which the Board recognizes as a plausible reading. The alternate reading hinges on the language providing that ''no purchase may be made *under authority of this paragraph*.'' The term ''this paragraph'' encompasses paragraph (13) of section 107 in its entirety. This reading applies the 5-percent limitation to all instruments (eligible obligations and notes) purchased pursuant to paragraph (13). The current regulation reflects such an interpretation, and the Board has made past statements in support of this reading.[83] This proposed rule constitutes a reconsideration of the NCUA's prior position. As noted, the NCUA has determined that the proposed regulatory change is more consistent with the language of the FCU Act and is more aligned with the different safety and soundness considerations with respect to eligible obligations in general and notes purchased from a liquidating credit union.

The proposed reading is better supported by accepted canons of statutory construction. The statutory construction canon of ''consistent usage'' logically presumes that different words denote different ideas.[84] Accordingly, the use of the terms ''eligible obligations'' and ''notes'' is intended to distinguish between two mutually exclusive categories of loans. Further, the canon holds that ''a word or phrase is presumed to bear the same meaning throughout a text.'' [85] The use of the word ''notes'' in paragraph 107(13) is appropriately interpreted consistently and exclusively to reference only notes made by a liquidating credit union to its members.

The proposed reading also aligns with the ''surplusage'' canon of statutory interpretation. Under this canon, ''every word and every provision is to be given effect if possible.'' [86] ''No word should be ignored. None should needlessly be given an interpretation that causes it to duplicate another provision or have no consequence.'' [87] The proposed interpretation accounts for language subsequent to ''under authority of this paragraph'' that modifies the clause's scope. This subsequent language specifies that the prohibition applies only ''if, upon the making of that purchase, the aggregate of the unpaid balances of *notes* purchased under authority of this paragraph would exceed 5 per centum of the unimpaired capital and surplus of the credit union.'' Thus, the limit's application is required only with respect to the purchase of ''notes,'' which, as stated previously, is appropriately narrowed to solely cover loans made by liquidating credit unions to their members. Reading the statute to require application of the 5-percent limitation to ''eligible obligations'' conflates the terms ''notes'' and ''eligible obligations,'' despite the different terminology Congress enacted. The effect of treating the terms as duplicative is to effectively ignore the use of the term ''notes,'' which should be separately considered under the surplusage canon.

It also bears noting that the stated rationale for original enactment of the 5-percent limitation does not apply to the purchase of eligible obligations. The 5-percent limitation language in section 107(13) of the FCU Act was added by Congress in 1968 and referred solely to notes of liquidating credit unions at that time because that statute did not refer to purchases of eligible obligations.[88] That

[78] *Id.* (emphasis added).

[79] Emphasis added.

[80] Emphasis added.

[81] 12 CFR 701.23(a).

[82] Under the current definition of ''eligible obligation'', there may be instances where the notes of the liquidating credit union members are also eligible obligations of the members of the purchasing FCU. The 5-percent limitation would apply to these loans as they fall within the more specific category of ''eligible obligations'' purchased from a liquidating credit union.

[83] For example, the preamble to the 1979 final rule implementing the NCUA's eligible obligations authority contained the following statement: ''The Administration feels that the language of Section 107(13) is clear, and that the best interpretation is that adopted in the proposed rule'' (that is, the currently codified regulatory text). 44 FR 27068, 27070 (May 9, 1979).

[84] Antonin Scalia & Bryan A. Garner, *Reading Law: The Interpretation of Legal Texts,* 148 (2012).

[85] *Id.*

[86] *Id.* at 145.

[87] *Id.*

[88] Public Law 90–375 (approved July 5, 1968) (Providing that: in accordance with rules and regulations prescribed by the Director, to purchase from any liquidating credit union notes made by individual members of the liquidating credit union at such prices as may be agreed upon by the board of directors of the liquidating credit union and the board of directors of the purchasing credit union, *but no purchase may be made under authority of this paragraph if, upon the making of that purchase, the aggregate of the unpaid balances of notes purchased under authority of this paragraph would exceed 5 per centum of the unimpaired*

language is identical to the current version of the statutory text and continues to refer solely to ''notes'' of liquidating credit unions. Prior to the amendment, FCUs lacked express statutory authority to purchase the loans of liquidating credit unions. As a result, liquidating credit unions were hampered in their efforts to dispose of their assets to repay their members. The Senate report accompanying the legislation explained that the change would ''greatly increase the market for the notes of liquidating credit unions and will prevent liquidating credit unions from having to go outside the credit union movement to liquidate their assets.'' [89] However, Congress was also mindful of the risks that might be posed in purchasing the loans of credit unions compelled to liquidate due to poor management decisions.[90] As a result, it opted to limit the ability of an FCU to purchase notes of liquidating credit unions to 5 percent of its unimpaired capital and surplus.[91]

The express authority to purchase eligible obligations was later added to the text of section 107(13) in 1977.[92] The legislative history from that time shows the amendment was intended to provide FCUs with flexibility to use secondary market facilities to enhance liquidity, especially in relation to real estate loans.[93] The purchase by an FCU of loans made to its own members is not analogous to, and does not pose the same inherent risk that, purchasing the notes of a liquidating credit union does. Accordingly, it is reasonable that Congress would elect not to mandate a limit on the ability of an FCU to make such purchases. This supposition is supported by Congress' decision to use the new term ''eligible obligations'' (and in granting the NCUA broad authority to define this term), rather than simply revising the existing scope of the term ''notes'' to include member loans. Further, the legislative history accompanying enactment of the 1977 amendments does not make any mention of the 5-percent limitation being applicable to eligible obligations.

The 1977 legislative history in several instances also refers to the amendment granting FCUs the ability to purchase the ''notes'' of its members. One could infer from this that the term ''eligible obligations'' was intended to be read synonymously with ''notes.'' [94] This reading appears at least plausible because the broad category of ''notes'' could be seen to encompass various debt instruments, including notes or written documents evidencing a member's eligible obligations. Such a reading, however, is not required and is inferior to the interpretation the Board is proposing in this rule for two reasons. First, Congress ultimately opted to use the term ''eligible obligations'' in the statutory amendment that was enacted. The codified text supersedes non-binding statements in the legislative record.[95] Secondly, and as discussed earlier, accepted canons of statutory construction favor an interpretation that provides individual terms with their own individual meaning.

For the preceding reasons, the NCUA has determined that the proposed regulatory change is more consistent with the language of the FCU Act. The NCUA also has determined that the amendment will not pose a safety and soundness risk due to the addition of principles-based risk management requirements. By amending the current rule to narrow the application of the 5-percent limitation to the aggregate of the unpaid balances of loans purchased from any source to instead apply to only the ''notes'' of a liquidating credit union, the Board intends to allow FCUs greater capacity, flexibility, and individual autonomy to establish their own risk tolerance limits for the amount of the loans of its members that can be purchased from any source other than a liquidating credit union. This includes other financial institutions, fintech companies, third-party loan acquisition channels such as CUSOs, and other loan-originating retailers.

While the narrower interpretation of section 107(13) of the FCU Act would remove the existing limit on the amount of eligible obligations that an FCU could purchase, establishing risk management expectations will minimize potential risk to the Share Insurance Fund while allowing FCUs more flexibility in how they manage their eligible obligation purchase activities. Proposed new § 701.23(b)(6), which is discussed in detail later in the part of the preamble on paragraph (b)(6), would outline minimum risk management standards that must be included in the written loan purchase policy for any FCU that plans to purchase eligible obligations. The Board believes these risk management standards should be part of the normal business practices at well-run FCUs that engage in the purchase of eligible obligations, and as such, should not represent an additional burden. It is the Board's view that the proposed changes would allow well-run FCUs more autonomy and flexibility in how they conduct their business. Provided the FCU can demonstrate and document that its loan purchase activity does not present a material risk to the viability or solvency of the FCU through the standards established in § 701.23(b)(6), the FCU should be able to establish its own internal standards to meet its business needs and the needs of its members.

The proposed rule would amend current § 701.23(b)(4) to remove the exclusions provided in paragraphs (b)(4)(i) through (iv) and revise the current language to apply the 5-percent limit to only notes purchased from liquidating credit unions. While the narrower interpretation of section 107(13) of the FCU Act would remove the existing restriction on the amount of eligible obligations an FCU could purchase, the new risk management requirements will minimize the potential increase in risk to the Share Insurance Fund, while allowing FCUs more flexibility in how they manage their loan purchase activities. Accordingly, proposed § 701.23(b)(4) would provide that the aggregate of the unpaid balance of notes purchased under paragraphs (b)(1)(ii) and (b)(2)(ii) of § 701.23 shall not exceed 5 percent of the unimpaired capital and surplus of the purchaser.

The Board invites comments concerning the proposed rule narrowing the application of the 5-percent limitation to only apply to the aggregate amount of ''notes'' that can be purchased by an FCU from a liquidating credit union. Should the Board consider defining the term ''notes'' as used to calculate the 5-percent limitation for the aggregate of the unpaid balances of notes an FCU could purchase from a liquidating credit union? If so, how should it be defined?

capital and surplus of the credit union. (emphasis added)).

[89] S. Rep. No. 1265, 90th Cong., 2d Sess., at 2 (June 18, 1968).

[90] *Statement of J. Deane Gannon, Director, Bureau of Federal Credit Unions, Social Security Administration, Department of Health, Education and Welfare,* FCU Act Amendments, Subcommittee on Financial Institutions of the Comm. on Banking and Currency, at 11–12 (May 24, 1968).

[91] H.R. Rep. No. 1372 (May 9, 1968).

[92] Public Law 95–22 (approved Apr. 19, 1977).

[93] H.R. Rep. No. 95–23, at 16 (Feb. 22, 1977).

[94] *See,* for example, 123 Cong. Rec. H 1521–32, at H–1524 (Daily ed. March 1, 1977) (Describing the amendment as providing for the ''Purchase and sale of notes of members.''); H.R. Rep. No. 95–23, at 16 (Feb. 22, 1977) (also describing amendment as pertaining to the ''Purchase and sale of notes''); and *Statement of C. Austin Montgomery, Administrator, National Credit Union Administration Before the Subcommittee on Financial Institutions Supervision, Regulation and Insurance Committee on Banking, Finance, and Urban Affairs, House of Representatives,* 95th Cong. 27 (1977) (''Temporary liquidity problems experienced by credit unions might be resolved by selling or pledging notes'').

[95] Scalia & Garner, *supra* note 7 at 64 (''[T]he purpose must be derived from the text, not from extrinsic sources such as legislative history or an assumption about the legal drafter's desires'').

Are there additional changes to this rule that the Board should consider in the future that would further facilitate credit union engagement with fintech companies and other third parties in a safe and sound manner?

Section 701.23(b)(5) Grandfathered Purchases

Proposed § 701.23(b)(5) would amend the current rule to broaden the grandfathering provision in current paragraph (b)(5). Current § 701.23(b)(5) provides that, subject to safety and soundness considerations, an FCU may hold any of the loans described in paragraph (b)(2) of this section provided it was authorized to purchase the loan and purchased the loan before July 2, 2012. The Board believes the proposed revisions to the current grandfathering provision would avoid placing undue burden on FCUs that were operating in compliance with the existing rule and avoid disrupting the existing eligible obligations market by forcing widespread divestments of the eligible obligations currently held in FCU loan portfolios. While the proposed grandfathering provision would allow FCUs to continue to hold eligible obligations that were purchased prior to the effective date of this rule, it does not exempt FCUs from conducting and updating risk assessments, establishing concentration limits, or monitoring the ongoing condition of the FCU's eligible obligation loan portfolio.

Accordingly, proposed § 701.23(b)(5) would provide that, subject to safety and soundness considerations, an FCU may hold any of the loans described in paragraph (b) of this section that were acquired before the effective date of the final rule approved by the Board; provided the transaction was in compliance with § 701.23 at the time the transaction was executed.

New § 701.23(b)(6)

The proposal would add a new paragraph (b)(6) to § 701.23, which would set forth basic due diligence, risk assessment, and management requirements that must be addressed in an FCU's internal written purchase policies.[96] An FCU's board of directors is responsible for planning, directing, and controlling the FCU's activities. To fulfill these duties, the board of directors must establish adequate policies. The introductory paragraph to proposed § 701.23(b)(6) would provide that the purchases of eligible obligations and notes of liquidating credit unions must comply with the purchasing FCU's internal written purchase policies, which must contain certain provisions.

The specific policy requirements, which are discussed in detail below, are part of the basic fiduciary responsibilities and duties required of boards of directors.[97] The requirements in the proposed rule address the basic elements necessary to administer a safe and sound loan purchase program.

As discussed previously, the Board is proposing that these requirements be added to mitigate the risk of removing certain regulatory limits on the purchase of loans by FCUs. The new requirements proposed under § 701.23(b)(6) are crafted to encourage credit discipline and promote safe and sound loan purchase programs, which are intended to protect the Share Insurance Fund. These requirements continue the Board's long-standing expectations for FCUs that purchase loans to appropriately identify and mitigate undue risk, while also providing FCUs greater flexibility to establish their own risk tolerance limits. These principles eliminate some unintended consequences of the prescriptive requirements in current § 701.23(b)(2) that, in some cases, resulted in FCUs managing their lending practices and balance sheets to regulatory restrictions instead of broader considerations for safe and sound lending practices.

The proposed framework would provide credit unions with expanded flexibility to develop loan purchase policies that are commensurate with the size, scope, type, complexity, and level of risk posed by the planned loan purchase activities. The proposed changes are intended to provide principles-based requirements that are useful for credit unions of any size or complexity to implement the appropriate level of due diligence, risk assessment, and management.

When determining whether to start a loan purchase program and developing related written policies, credit unions should consider whether the proposed loan purchase activities are consistent with the FCU's overall business strategy and risk tolerances, and financial and operational capabilities. Loan purchase, sale, or pledge activities that are inconsistent with the FCU's risk tolerance levels or beyond management's ability to manage can pose material risks to an FCU's financial or operational condition.

The risk management expectations that are outlined in this proposal reflect the key components of long-standing supervisory expectations as communicated to credit unions through NCUA Letters to Credit Unions (LCU), Supervisory Letters, and the Examiner's Guide. The NCUA specifically requests comment on the written purchase policy requirements being proposed in paragraph (b)(6) of the rule. Are the principles-based due diligence, risk assessment, and management requirements proposed sufficient to offset the risk associated with removing the CAMELS rating and ''well capitalized'' requirements for a credit union to purchase and hold eligible obligations from a FICU? Are there other principles-based safety and soundness or compliance criteria the Board should consider that would mitigate the risk of removing certain prescriptive requirements from the rule?

New § 701.23(b)(6)(i)

Proposed new § 701.23(b)(6)(i) would require FCUs to perform due diligence on the seller, and any applicable counterparties, before purchasing an eligible obligation. Conducting due diligence on third parties is a long-standing expectation for credit unions engaging in third-party relationships and when introducing new loan programs and products, as noted in NCUA LCU 01–CU–20 (November 2001), NCUA LCU 08–CU–26 (November 2008), and NCUA LCU 10–CU–03 (March 2010).[98]

Third-party relationships with credit unions have resulted in financial stress due to unexpected costs, legal disputes, and asset losses on several occasions. Due diligence reviews are important because they assist credit unions in risk identification and mitigation when engaging in a new loan program and when partnering with outside parties to enhance services to members. Failure to complete adequate due diligence can result in the acquisition of loan volumes that exceed the board's risk appetite, loan types that go beyond management's ability to manage, or loan types or volume that exceed the capabilities of current loan processing and management information systems. The use of third parties can add complexity and additional risk to a credit union's activities and may also expose the credit union to consumer compliance and other legal risks. For example, failure to conduct adequate due diligence could lead to an FCU entering into agreements with a third party that may discontinue services in the future. This could lead to disruptions in member service, uncollected payments on loans, and potential losses if the third party fails to

[96] A credit union's written loan purchase policies may be incorporated into the written lending policies required under § 741.3(b)(2).

[97] *See* §§ 701.4(b)(4), 701.21(c)(2), and 741.3(b)(2).

[98] *Available at https://ncua.gov/regulation-supervision/letters-credit-unions-other-guidance.*

remit funds that are due to the purchasing FCU.

The responsibility to perform appropriate due diligence remains with the FCU's board of directors and management and cannot be outsourced. Overreliance on the due diligence information provided by a third party without independent review by the FCU's board and management could result in unsafe and unsound practices.

The proposed rule allows FCUs the flexibility to determine the level and depth of due diligence reviews that are necessary based on the level of risk posed by the loans being purchased and the third-party relationships. Several factors may be considered when determining the appropriate nature of due diligence for third-party loan purchases and programs, including:

- the transaction's complexity;
- the purchasing FCU's internal lending policies and procedures;
- the transaction's size relative to the FCU's existing loan portfolio, concentrations, and net worth level; and
- the purchasing FCU's management and staff expertise regarding the types of loans being purchased.

Additionally, FCUs can take a tiered approach when establishing their due diligence processes in their loan purchase policies. For example, when conducting background checks the FCU can determine how best to assess a third party's business reputation, potential conflicts of interest, experience, and compliance with federal and state laws, rules, and regulations based on the type of relationship with the third party and its risk exposure.

Accordingly, proposed § 701.23(b)(6)(i) would provide that the purchasing FCU's written purchase policy must require that the purchasing FCU conduct due diligence on the seller of the loans and other counterparties to the transaction prior to the purchase.

New § 701.23(b)(6)(ii)

Proposed new § 701.23(b)(6)(ii) would require FCUs to establish risk assessment and risk management processes for purchase activities. Conducting risk assessments and implementing risk management processes reflect the NCUA's long-standing expectation that credit unions incorporate these activities in relationships with third parties as outlined in NCUA LCU 07–CU–13 (April 2008), Evaluating Third-Party Relationships; NCUA LCU 22–CU–05 (March 2022), CAMELS Rating System; and NCUA Letter to FCUs 02–FCU–09 (March 2002), Risk-Focused Examination Program.[99] The purchase of loans can provide an FCU with a wide range of benefits, including achieving strategic loan growth, managing liquidity, adjusting risk exposures, and enhancing the services provided to members. However, an FCU that starts a new lending program, including the purchase or sale of loans, or engages with third parties without fully understanding the associated risks, may expose itself to credit, interest rate, liquidity, transaction, compliance, strategic, or reputation risk. Risk assessments allow credit unions to better understand the risk involved in new products and services to ensure the board has effective processes in place to control the risk. Not understanding these associated risks may result in the FCU operating outside of the board's risk appetite and can result in elevated risk to the Share Insurance Fund. FCUs are ultimately responsible for safeguarding member assets and ensuring sound operations.

Adequate risk management processes include ongoing monitoring and oversight of the loan purchase program. This includes formal reporting to the board of directors and the FCU's senior management, which will ensure the board is able to fulfill its duties. An FCU's management reporting should be timely and commensurate with the size, complexity, and risk exposure of the FCU. For example, the board of directors should be informed when targets are met or exceeded, or limits breached. Reports should also consist of appropriate information that the board of directors and management could use to make informed decisions and take timely corrective action when warranted. For effective governance, an FCU's board of directors and management must understand the nature and level of risk associated with the FCU's purchased loan portfolio and program and receive periodic updates and reports on the performance of the purchased loan portfolio.

The proposed rule provides FCUs the flexibility to tailor their risk assessment and management processes to fit within their governance framework and other operations, while providing a basic framework to follow when developing their initial and ongoing risk assessment and management processes. Accordingly, proposed § 701.23(b)(6)(ii) would provide that the purchasing FCU's internal written purchase policies must establish risk assessment and risk management process requirements that are commensurate with the size, scope, type, complexity, and level of risk posed by the planned loan purchase activities.

New § 701.23(b)(6)(iii)

Proposed new § 701.23(b)(6)(iii) would require FCUs to establish certain internal underwriting and ongoing monitoring standards for eligible obligation purchase activities. Underwriting is the foundation of lending. Without ensuring that underwriting standards are in place that adequately address how to analyze a borrower's ability to repay their debt, the board will not be able to fulfill its responsibilities for the safety and soundness of the FCU's lending activities. By this same logic, the board must also monitor the level of credit risk within the credit union's loan portfolio. Changing economic conditions at the local, regional, or national level can materially impact the likelihood that the credit union's outstanding loans are repaid. For example, the closure of a local business that is a large employer of the credit union's members could significantly change the risk profile of the credit union's loan portfolio. Changing levels of credit risk within the FCU's existing loan portfolio (including eligible obligations) may necessitate strategic changes or mitigating actions. If the level of credit risk begins to exceed the board's risk appetite, then risk exposures may need to be adjusted. Depending on the circumstances, this could include, but is not limited to, restricting the purchase of new eligible obligations, implementing more conservative underwriting standards, or potentially divesting parts of the existing loan portfolio.

The FCU's internal policies must address the level of underwriting to be performed for the purchase of loans. Underwriting should identify all risks that could materially influence the purchasing FCU's decision to proceed with a loan purchase. Appropriate underwriting standards that adequately address how to analyze a borrower's ability to repay their loan and the support provided by collateral are a basic tenet of lending and help ensure that the FCU will be repaid, which protects its members and the Share Insurance Fund. Without appropriate underwriting standards, an FCU will not be able to accurately assess its risk of credit loss. Originating or purchasing loans to high credit risk borrowers without appropriately understanding and planning for that risk can result in unexpectedly high loss rates that negatively impact earnings and net worth, which may impair the viability of the credit union and pose a risk to the Share Insurance Fund. A lack of

[99] *Available at https://ncua.gov/regulation-supervision/letters-credit-unions-other-guidance.*

adequate underwriting standards can also result in adverse risk selection, whereby high credit risk borrowers are only able to obtain loans from institutions with lax underwriting, resulting in the FCU attracting borrowers with a much higher risk of default.

An FCU engaging in loan purchases should conduct an independent credit analysis and assessment of the borrower's creditworthiness and ability-to-repay, the support provided by collateral if relied on as part of the credit decision, and changes to the risk profile of the purchased loans. A purchasing FCU should not rely on the underwriting and analysis performed by the seller, or work performed by other third-party underwriters on behalf of a seller. To do so is an unsafe and unsound practice.

An FCU can leverage its current internal underwriting policies for similar loan types when developing its loan purchase policies. Performing credit and collateral analysis as if it were the originator should result in purchased loans that are consistent with the board of director's overall business strategy, risk tolerances, and credit quality standards. To the extent a purchasing FCU relies on a third party's credit models for credit decisions, the purchasing FCU should perform due diligence on the credit model. An FCU is not prohibited from relying on a qualified and independent third party to perform model validation. However, the purchasing FCU should review the model validation to determine if it is sufficient.

The purchasing FCU's internal loan purchase policies should outline and identify the loan types that are acceptable for purchase. For example, acceptable loan types could include residential real estate (1–4 family or multi-family first lien and/or junior lien), solar loans, automobile loans, student loans, unsecured loans, out-of-territory loans, commercial loans, or government guaranteed loans (guaranteed and/or unguaranteed portion).

The loan purchase policy should address the level and depth of the underwriting and analysis that is required for each loan type permitted to be purchased based on the specific loan category, type, size, complexity, and risk profile of the borrower. The proposed rule allows flexibility to establish those parameters, while providing a basic framework for FCUs to follow when developing their policies.

Accordingly, proposed § 701.23(b)(6)(iii) would provide that the purchasing FCU's internal written purchase policies must establish internal underwriting and ongoing monitoring standards that are commensurate with the size, scope, type, complexity, and level of risk posed by the loan purchase activities. Proposed paragraph (b)(6)(iii) would provide further that underwriting and ongoing monitoring standards must address the borrower's creditworthiness and ability to repay, and the support provided by collateral if the collateral was used as part of the credit decision.

New § 701.23(b)(6)(iv)

Proposed new § 701.23(b)(6)(iv) would provide that the purchasing FCU's internal written purchase policy must require that the written purchase agreements include certain language. A well-written loan purchase agreement can minimize conflicts between the FCU and other parties to the agreement. The Board believes that any written loan purchase agreement must clearly delineate the roles, duties, and obligations of the seller, the purchasing FCU, servicer, and any other parties associated with the agreement, as applicable. The proposed rule establishes minimum provisions that any well-written loan purchase agreement must address.

The written loan purchase agreement is a critical component of any third-party relationship. In addition to establishing the rights and obligations of each party to the loan agreement, it should clearly address how the relationship operates. The written loan purchase agreement should fully describe the roles and responsibilities of all parties to the agreement, including any subcontractors. A well-written loan purchase agreement should address dispute resolution, requirements for any ongoing credit information if necessary for the loan type, remedies upon loan default and bankruptcy, identify which party bears the costs of collateral disposition, whether there are recourse arrangements for early pay-off, and if there is an obligation for the purchasing FCU to make any additional purchases or credit advances.

The purchasing FCU's board of directors and management should understand that it may have limited control over credit decisions for loans purchased in part, including limitations on the ability of the purchasing FCU to participate in loan modifications, act on defaulted loans, or decline to make additional advances if the purchasing FCU deems such advances are not prudent in relation to the loan quality. The written loan agreement must address these circumstances, and other conditions under which the parties to the agreement may replace the servicer if services are not performed in accordance with the terms of the written loan purchase agreement. The purchasing FCU must also know the location and custodian for the original loan documents if the original loan documents are not required to be transferred to the purchasing FCU as part of the loan purchase transaction. The purchasing FCU could be required to provide the original loan documents to various parties involved in the administration and collection of the purchased loans. The purchasing FCU would therefore need to know where the original documents were located and which party to contact should the purchasing FCU need to obtain the original loan documents.

The written loan purchase agreement must, prior to the loan purchase transaction, identify the specific loan or loans being purchased, and the interest being purchased. A loan purchase transaction may involve a single loan or multiple loans, purchased in whole or in part. The documentation, for example, can be as simple as an addendum or schedule identifying each loan, provided the addendum or schedule is incorporated by reference into the loan purchase agreement. This provision clarifies in the existing rule that the loan purchase transaction involves the purchase of individual loans, and it is not the purchase of an investment interest in a pool of loans. Accordingly, for all the reasons outlined above, proposed § 701.23(b)(6)(iv) would provide that the purchasing FCU's internal written purchase policy must require that the written purchase agreement include: the specific loans being purchased (either directly in the agreement or through a document that is incorporated by reference into the agreement); the location and custodian for the original loan documents; an explanation of the duties and responsibilities of the seller, servicer, and all parties with respect to all aspects of the loans being purchased, including servicing, default, foreclosure, collection, and other matters involving the ongoing administration of the loans, if applicable; and the circumstances and conditions under which the parties to the agreement may replace the servicer when the seller retains the servicing rights for the loans being purchased, if applicable.

New § 701.23(b)(6)(v)

Proposed new § 701.23(b)(6)(v) would require that FCUs establish certain portfolio concentration limits. Excessive concentration risk can severely impact the financial condition of an FCU. High concentrations in areas experiencing economic distress could result in significant losses exceeding an FCU's net worth. An FCU's board of directors and management have the responsibility to identify, manage, monitor, and control the risks facing the FCU, including concentration risk. FCU management must know what their concentration risks are and be able to demonstrate appropriate risk management and mitigation practices to minimize the risk of significant financial condition decline. Accordingly, proposed § 701.23(b)(6)(v) would provide that a purchasing FCU's internal written purchase policies must establish portfolio concentration limits by loan type and risk category in relation to net worth that are commensurate with the size, scope, and complexity of the credit union's loan purchases. Paragraph (b)(6)(v) would provide further that the policy limits must take into account the potential impact of loan concentrations on the purchasing credit union's earnings, loan loss reserves, and net worth.

An FCU's loan purchase policy should establish credit underwriting and administration requirements that address the risks and characteristics unique to the loan types permitted for purchase. An FCU's loan purchase policy concentration limits should be considered for the aggregate amount of total purchased loans, for each loan type, risk factor, or category permitted. For example, concentration limits can be set by loan or collateral type but may also be set by associated borrower, origination channel, geographic area, or other risk category as applicable.

An FCU's board of directors should establish concentration risk limits commensurate with its net worth levels and consider how the limits fit into the overall strategic plan of the FCU. When credit union loan portfolios are concentrated in a small number of loan products that are significantly exposed to similar or correlated risk factors, a single event can impact a large portion of the loan portfolio and result in elevated losses that, if not managed appropriately, can lead to the credit union's failure. Since the year 2000, more than 50 percent of the NCUA's postmortems and material loss reviews have cited concentration risk as a central component of credit union failures. An FCU's board of directors should use a comprehensive perspective when developing loan purchase concentration policy limits, including identifying outside forces (such as economic or housing price uncertainty) that would affect the ability to manage concentration risk. The parameters set by the board of directors should be specific to each portfolio and should include limits on loan types and third-party relationship exposure, at a minimum. The concentration risk limits should correlate to the FCU's overall growth objectives, financial targets, and net worth plan. The concentration risk limits set forth in the FCU's policy should be closely linked to those codified in related policies, including, but not limited to, real estate loans, member business loans, asset/liability management (ALM), and investment policies. Concentrations that exceed net worth must be monitored carefully, and the board of directors should document an adequate rationale for undertaking that level of risk.[100]

New § 701.23(b)(6)(vi)

Proposed new § 701.23(b)(6)(vi) would address when a legal review of agreements or contracts would be required. The written loan purchase agreement is a critical component of any third-party relationship and, as such, the requirement for a legal review is a key element in the overall risk mitigation and management process. By obtaining legal advice regarding third-party contracts, an FCU can ensure its legal and business interests are appropriately protected, and the board of directors and management understand the risks, rights, and responsibilities of each party to the written loan purchase agreement. Accordingly, proposed § 701.23(b)(6)(vi) would provide that an FCU's internal written purchase policy must address when a legal review of agreements or contracts will be performed to ensure that the legal and business interests of the credit union are protected against undue risk.

A legal review of the written loan purchase agreements and contracts will help an FCU ensure that the board of directors and management understand the rights and responsibilities of each party. For example, the review could identify which party bears the costs of collateral disposition, whether there are recourse arrangements, or whether the agreement includes a commitment for the purchasing FCU to make additional loan purchases and describe the interest being purchased. A legal review may also reduce a credit union's legal, compliance, or reputation risk by ensuring that the written loan purchase agreement complies with all applicable state and federal laws.

[100] *See* attachment to NCUA Letter to FICUs 10–CU–03 (March 2010) available at *https://www.ncua.gov/files/letters-credit-unions/LCU2010-03Encl.pdf.*

Further, an FCU should understand what actions it may take if the contract is breached, or services are not performed as expected. For example, the legal review could determine if the written loan purchase agreements include recourse language that requires a seller to buy back loans with missing documents, made outside of policy, or otherwise not in conformance with representations and warranties. The written loan purchase agreement is a critical component of any third-party relationship and, as such, a legal review is a key element in the overall risk mitigation and management process.

Section 701.23(c) Sale

The proposal would make a non-substantive conforming change to current § 701.23(c)(1). In addition, the proposal would make certain substantive changes to paragraph (c)(2) and add new paragraphs (c)(3) and (4), which are discussed in more detail in the following paragraphs. No changes would be made in the introductory sentence to current § 701.23(c).

Section 701.23(c)(1)

As required by the changes discussed below, proposed § 701.23(c)(1) would make a conforming amendment to current § 701.23(c)(1). The conforming amendment would remove the ''and'' at the end of the provision to allow for an additional provision to be added under § 701.23(c)(2). No substantive change to this provision is intended.

Section 701.23(c)(2)

The proposal would amend current § 701.23(c)(2) to change the retention requirements for the written agreement and schedule of eligible obligations sold by an FCU. The Board believes that this would result in only a minor technical change to current § 701.23(c)(2). Under the proposed rule, the FCU selling the eligible obligations would still be required to retain the written loan sales agreement and a schedule of the eligible obligations covered by the agreement. The Board acknowledges the requirement for the FCU to retain the written loan sales agreement and schedule of the eligible obligations in the seller's office could imply that the written loan sales agreement and schedule be retained in a hard-copy format, which is outdated given the current digital environment. An FCU might choose to store its records in electronic format, in the cloud, or housed in off-site servers or databases.

This proposed change would align this requirement with the NCUA's regulations and guidelines for FICUs on records preservation programs. Under part 749, the NCUA does not require or recommend a particular format for record retention. If the credit union stores records on microfilm, microfiche, or in an electronic format, the stored records must be accurate, reproducible, and accessible to an NCUA examiner.[101] If records are stored on the credit union premises, they should be immediately accessible upon the examiner's request; if records are stored by a third party or off site, then they should be made available to the examiner within a reasonable time after the examiner's request. The credit union must maintain the necessary equipment or software to permit an examiner to review and reproduce stored records upon request. The credit union should also ensure that the reproduction is acceptable for submission as evidence in a legal proceeding.[102] Accordingly, proposed § 701.23(c)(2) would provide that a written agreement, and a schedule of the eligible obligations covered by the agreement, is retained by the selling credit union that identifies the specific loans being sold either directly in the agreement or through a document that is incorporated by reference into the agreement.

New § 701.23(c)(3)

The proposal would add new paragraph (c)(3) to § 701.23 to require a legal review of the written agreement to protect the legal and business interests of the selling FCU. A legal review of the written loan sales agreements and contracts will help an FCU ensure that the board of directors and management understand the rights and responsibilities of each party. For example, the legal review would make clear which party bears the costs of collateral disposition, whether there are recourse arrangements, whether the agreement includes a commitment for the purchasing credit union to make additional loan purchases, and whether it describes the interest being purchased. The legal review would also ensure that the written loan sales agreement complies with all applicable state and federal laws, helping to minimize a credit union's legal, compliance, and reputation risk. The legal review should address loan and collateral documentation and information that the selling party is required to share with the purchasing party, status reports on payments and interest accrual, exit strategies, procedures for modifying loan terms, notification of adverse loan events, and collection procedures if servicing rights are retained by the seller. Further, an FCU should understand what actions it may take if the contract is breached or services are not performed as expected. The written loan sales agreement is a critical component of any third-party relationship and, as such, the requirement for a legal review is a key element in the overall risk mitigation and management process.

Accordingly, proposed § 701.23(c)(3) would require a legal review of the written agreement is completed that includes the terms, recourse, and risk-sharing arrangements, and, as applicable, loan administration and controls, to ensure that the selling FCU's legal and business interests are protected from undue risks.

Section 701.23(d) Pledge

The proposed rule would amend current § 701.23(d)(1)(iii) to amend the retention requirements for agreements covering eligible obligations pledged by an FCU. The Board believes that this would result in only a minor technical change to current § 701.23(d)(1)(iii). Under the proposed rule, the FCU pledging the eligible obligations would still be required to retain the written agreement covering the pledging arrangement. The Board acknowledges the requirement for the FCU that pledges the eligible obligations to retain the written agreement in the office could imply that the written agreement should be retained in a hard-copy format, which is outdated given the current digital environment. An FCU might choose to store its records in electronic format, in the cloud, or housed in off-site servers or databases. The Board's intent is that the FCU that pledges the eligible obligations make the written agreement covering the pledging arrangement available upon request.[103]

This proposed change would align this requirement with the NCUA's regulations and guidelines for FICUs on records preservation programs. Under part 749, the NCUA does not require or recommend a particular format for record retention. If the credit union stores records on microfilm, microfiche, or in an electronic format, the stored records must be accurate, reproducible, and accessible to an NCUA examiner.[104] If records are stored on the credit union premises, they should be immediately accessible upon the examiner's request; if records are stored by a third party or off site, then they should be made available to the examiner within a reasonable time after the examiner's request. The credit union must maintain the necessary equipment or software to permit an examiner to review and reproduce stored records upon request. The credit union should also ensure that the reproduction is acceptable for submission as evidence in a legal proceeding.[105]

Accordingly, proposed § 701.23(d)(1)(iii) would require that a written agreement covering the pledging arrangement is retained by the credit union that pledges the eligible obligations.

Section 701.23(g) Payments and Compensation

The proposed rule would amend current § 701.23(g) by adding a paragraph heading. The Board believes that this would result in only a minor technical change to paragraph (g). The amended rule would add the three-word descriptive heading ''payments and compensation'' for this section of the rule, but does not add any additional requirements or make any other changes to this section of this rule. Accordingly, proposed § 701.23(g) would have the paragraph heading ''payments and compensation.''

Section 701.23(i) Temporary Regulatory Relief in Response to COVID–19

The proposed rule would not extend the regulatory relief in § 701.23(i) that the Board approved in April of 2020 in response to COVID–19. This temporary relief is set to sunset on December 31, 2022. Current paragraph (i) provides that: notwithstanding § 701.23(b), during the period commencing on April 21, 2020, and *concluding on December 31, 2022,* an FCU may: purchase, in whole or in part, and within the limitations of the board of directors' written purchase policies, any eligible obligations pursuant to paragraph (b)(1)(i) and (b)(2)(i) without regard to whether they are loans the credit union is empowered to grant or are refinancing to ensure the obligations are ones the purchasing credit union is empowered to grant; and purchase and hold the obligations described in § 701.23(b)(2)(i) through (iv) if the FCU's CAMELS composite rating is ''1,'' ''2,'' or ''3''.[106]

As provided in current paragraph (i), the temporary regulatory relief provided under the paragraph expires on December 31, 2022. The Board temporarily modified certain regulatory

[101] *See* 12 CFR 749.5.

[102] *See generally* part 749; *and* NCUA Legal Op. 07–0812 (Jan. 2008), *available at https://www.ncua.gov/regulation-supervision/legal-opinions/2008/electronic-retention-records.*

[103] *See* § 749.2.

[104] *See* 12 CFR 749.5.

[105] *See generally* part 749; *and* NCUA Legal Op. 07–0812 (Jan. 2008), *available at https://www.ncua.gov/regulation-supervision/legal-opinions/2008/electronic-retention-records.*

[106] Emphasis added.

requirements to help ensure that FICUs remained operational and liquid during the COVID–19 pandemic. The Board concluded, at the time, that the amendments would provide FICUs with the necessary flexibility in a manner consistent with the NCUA's responsibility to maintain the safety and soundness of the credit union system. The Board provided this temporary regulatory relief to assist credit unions in navigating the national emergency resulting from the COVID–19 pandemic.[107] Since the implementation of temporary regulatory relief, many credit unions have generally resumed normal, pre-pandemic operations. The majority of the COVID–19 pandemic health mitigation efforts imposed by states as well as the federal government have been lifted (non-essential business closures, social distancing requirements, and mask mandates).

The expiration date of the temporary final rule was initially extended through the close of December 31, 2021, by publishing the extension in the **Federal Register** on December 22, 2020.[108] Due to the continued impact of COVID–19, the Board decided it was necessary to further extend the effective period of these temporary modifications until December 31, 2022, by publishing the extension in the **Federal Register** on December 22, 2021.[109] The Board is proposing to remove current paragraph (i) from § 701.23 as part of any final rule issued after December 31, 2022.

B. Part 714—Leasing

Section 714.9 [Removed and Reserved]

Current § 714.9 provides that the indirect leasing arrangements of an FCU are not subject to the eligible obligation limit if they satisfy the provisions of § 701.23(b)(3)(iv) that require that FCUs make the final underwriting decision and that the lease contract is assigned to the FCU very soon after it is signed by the member and the dealer or leasing company. The reference in current § 714.9 cites to § 701.23(b)(3)(iv), but there is no paragraph (b)(3)(iv) in that section. It is clear from the ''eligible obligations limit'' language in current § 714.9, however, that the cross citation is intended to reference the exclusion from the 5-percent limitation in current § 701.23(b)(4)(iv). Because this proposal would amend § 701.23(b)(4) to remove paragraph (b)(4)(iv) and would no longer apply the 5-percent limitation to any purchases of eligible obligations, as explained earlier in the preamble, current § 714.9 would be rendered moot by this proposal. Accordingly, this proposal would remove the language in current § 714.9 and reserve the blank section for future use.

The Board seeks comments specifically on the placement of the definition of indirect leasing arrangement in the NCUA's regulations. The proposed definition would apply throughout the NCUA's regulations and is being proposed for inclusion in § 701.21 alongside the related definition of indirect lending arrangement that the Board is proposing to add to new § 701.21(c)(9)(i). The Board requests comments on whether stakeholders would find it clearer or more user-friendly to codify this definition in part 714.

IV. Regulatory Procedures

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires that, in connection with a notice of proposed rulemaking, an agency prepare and make available for public comment an initial regulatory flexibility analysis that describes the impact of a proposed rule on small entities. A regulatory flexibility analysis is not required, however, if the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (defined for purposes of the RFA to include credit unions with assets less than $100 million) [110] and publishes its certification and a short, explanatory statement in the **Federal Register** together with the rule.

The Board fully considered the potential economic impact of the proposed changes during the development of the proposed rule. As noted in the preamble, the proposed rules would clarify the NCUA's current regulations and provide additional flexibilities to FICUs, making it easier to take advantage of advanced technologies and opportunities offered by the fintech sector.

The proposed rule would not impose any new significant burden on FICUs and may ease some existing requirements. Small FICUs are not obligated to buy and sell eligible obligations and loan participations. Additionally, while the proposed rule introduces risk management and due diligence policy expectations, FICUs have the flexibility to tailor required processes and policies to fit within their existing governance framework and commensurate with their size and complexity. Accordingly, the NCUA certifies that it would not have a significant economic impact on a substantial number of small FICUs.

Paperwork Reduction Act

The Paperwork Reduction Act of 1995 (PRA) applies to rulemakings in which an agency by rule creates a new paperwork burden on regulated entities or modifies an existing burden.[111] For purposes of the PRA, a paperwork burden may take the form of a reporting, disclosure, or recordkeeping requirement, each referred to as an information collection. The NCUA may not conduct or sponsor, and the respondent is not required to respond to, an information collection unless it displays a currently valid Office of Management and Budget (OMB) control number.

The rule as previously published contains an information collection in the form of a written policy requirement and a transaction documentation requirement, covered by OMB control numbers 3133–0127 and 3133–0141. The proposed changes to part 701 would not result in a change in burden, and there are no new information collection requirements associated with this proposed rule.

Executive Order 13132

Executive Order 13132 encourages independent regulatory agencies to consider the impact of their actions on state and local interests. The NCUA, an independent regulatory agency as defined in 44 U.S.C. 3502(5), voluntarily complies with the principles of the executive order to adhere to fundamental federalism principles. This proposed rule would reduce regulatory burdens on, and expand the authority of, federally insured credit unions, including federally insured, state-chartered natural-person credit unions to purchase certain loans and loan participations. It may have, to some degree, a direct effect 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. It does not, however, rise to the level of material impact for purposed of Executive Order 13132.

Assessment of Federal Regulations and Policies on Families

The NCUA has determined that this proposed rule will not affect family well-being within the meaning of section 654 of the Treasury and General Government Appropriations Act, 1999,

[107] *See* 85 FR 22010 (April 21, 2020).

[108] *See* Id.

[109] 85 FR 22010.

[110] *See* 80 FR 57512 (Sept. 24, 2015).

[111] 44 U.S.C. 3507(d).

Public Law 105–277, 112 Stat. 2681 (1998).

List of Subjects

12 CFR Part 701

Advertising, Aged, Civil rights, Credit, Credit unions, Fair housing, Individuals with disabilities, Insurance, Marital status discrimination, Mortgages, Religious discrimination, Reporting and recordkeeping requirements, Sex discrimination, Signs and symbols, Surety bonds.

12 CFR Part 714

Credit unions, Leasing, Reporting and recording keeping requirements.

By the National Credit Union Administration Board on December 15, 2022.

Melane Conyers-Ausbrooks,

Secretary of the Board.

For the reasons discussed above, the Board proposes to amend 12 CFR parts 701 and 714 as follows:

PART 701—ORGANIZATION AND OPERATION OF FEDERAL CREDIT UNIONS

■ 1. The authority citation for part 701 continues to read as follows:

Authority: 12 U.S.C. 1752(5), 1755, 1756, 1757, 1758, 1759, 1761a, 1761b, 1766, 1767, 1782, 1784, 1785, 1786, 1787, 1788, 1789. Section 701.6 is also authorized by 15 U.S.C. 3717. Section 701.31 is also authorized by 15 U.S.C. 1601 *et seq.;* 42 U.S.C. 1981 and 3601–3610. Section 701.35 is also authorized by 42 U.S.C. 4311–4312.

■ 2. Amend § 701.21 by adding paragraph (c)(9) to read as follows:

§ 701.21 Loans to members and lines of credit to members.

* * * * *

(c) * * *

(9) *Indirect lending and indirect leasing arrangements*—(i) *Definitions.* For purposes of this chapter, the following definitions apply:

Indirect leasing arrangement means a written agreement to purchase leases from the leasing company where the purchaser makes the final underwriting decision, and the lease agreement is assigned to the purchaser very soon after it is signed by the member and the leasing company.

Indirect lending arrangement means a written agreement to purchase loans from the loan originator where the purchaser makes the final underwriting decision regarding making the loan, and the loan is assigned to the purchaser very soon after the inception of the obligation to extend credit.

(ii) *Indirect lending.* A loan acquired pursuant to an indirect lending arrangement, and that meets the requirements of this section, is classified as a loan and not the purchase of a loan for purposes of this chapter.

(iii) *Indirect leasing.* A lease acquired pursuant to an indirect leasing arrangement, and that meets the requirements of part 714 of this chapter, is classified as a lease and not the purchase of a lease for purposes of this chapter.

* * * * *

■ 3. Amend § 701.22 by:

■ a. Revising the introductory text; and

■ b. Revising the definition of ''Originating lender'' in paragraph (a).

The revisions read as follows:

§ 701.22 Loan participations.

This section applies only to loan participations as defined in paragraph (a) of this section. It does not apply to the purchase of an investment interest in a pool of loans. This section establishes the requirements a federally insured credit union must satisfy to purchase a participation in a loan. Federally insured state-chartered credit unions are required by § 741.225 of this chapter to comply with the loan participation requirements of this section. This section does not apply to corporate credit unions, as that term is defined in § 704.2 of this chapter.

(a) * * *

Originating lender means the participant with which the borrower initially or originally contracts for a loan and who, thereafter or concurrently with the funding of the loan, sells participations to other lenders. Originating lender includes a participant that acquires a loan through an indirect lending arrangement as defined under § 701.21(c)(9).

* * * * *

■ 4. Amend § 701.23 by:

■ a. Revising the introductory text, paragraph (a), the heading to paragraph (b), and paragraph (b)(1)(ii);

■ b. Removing the word ''mortage'' from the first sentence in paragraph (b)(1)(iv) and adding in its place the word ''mortgage'';

■ c. Revising paragraphs (b)(2) introductory text, (b)(2)(ii), (b)(3)(ii), and (b)(4) and (5);

■ d. Adding paragraph (b)(6);

■ e. Revising paragraphs (c)(1) and (2);

■ f. Adding paragraph (c)(3);

■ g. Revising paragraph (d)(1)(iii); and

■ h. Adding a heading to paragraph (g).

The revisions and additions read as follows:

§ 701.23 Purchase, sale, and pledge of loans.

This section governs a Federal credit union's purchase, sale, or pledge of all or part of a loan to one of its own members, subject to certain exceptions. For purchases of eligible obligations, except as otherwise described under paragraph (b) of this section, the borrower must be a member of the purchasing Federal credit union before the purchase is made.

(a) *Definitions.* For purposes of this section:

Eligible obligation means a whole loan or part of a loan (other than a note held by a liquidating credit union) that does not meet the definition of a loan participation under § 701.22(a).

Liquidating credit union means:

(i) In the case of a voluntary liquidation, a credit union is a liquidating credit union as of the date the members vote to approve liquidation.

(ii) In the case of an involuntary liquidation, a credit union is a liquidating credit union as of the date the board of directors is served an order of liquidation issued by either the NCUA or the state supervisory authority.

Student loan means a loan granted to finance the borrower's attendance at an institution of higher education or at a vocational school, which is secured by and on which payment of the outstanding principal and interest has been deferred in accordance with the insurance or guarantee of the Federal Government, of a state government, or any agency of either.

(b) *Purchase of loans.* (1) * * *

(ii) Notes of a liquidating credit union's individual members, from the liquidating credit union;

* * * * *

(2) *Purchases of obligations from a FICU.* A Federal credit union may purchase and hold the following obligations, provided that it would be empowered to grant them:

* * * * *

(ii) *Notes of a liquidating credit union.* Notes of a liquidating credit union, without regard to whether they are notes of the liquidating credit union's members;

* * * * *

(3) * * *

(ii) A written agreement and a schedule of the eligible obligations covered by the agreement are retained by the purchaser; and

* * * * *

(4) The aggregate of the unpaid balance of notes purchased under paragraphs (b)(1)(ii) and (b)(2)(ii) of this section shall not exceed 5 percent of the unimpaired capital and surplus of the purchaser.

(5) Subject to safety and soundness considerations, a Federal credit union

may hold any of the loans described in paragraph (b) of this section that were acquired before [EFFECTIVE DATE OF THE FINAL RULE]; provided the transaction was in compliance with this section at the time the transaction was executed.

(6) Purchases of eligible obligations and notes of liquidating credit unions must comply with the purchasing Federal credit union's internal written purchase policies, which must:

(i) Require that the purchasing Federal credit union conduct due diligence on the seller of the loans and other counterparties to the transaction prior to the purchase.

(ii) Establish risk assessment and risk management process requirements that are commensurate with the size, scope, type, complexity, and level of risk posed by the planned loan purchase activities.

(iii) Establish internal underwriting and ongoing monitoring standards that are commensurate with the size, scope, type, complexity, and level of risk posed by the loan purchase activities. Underwriting and ongoing monitoring standards must address the borrower's creditworthiness and ability to repay, and the support provided by collateral if the collateral was used as part of the credit decision.

(iv) Require that the written purchase agreement include:

(A) The specific loans being purchased (either directly in the agreement or through a document that is incorporated by reference into the agreement);

(B) The location and custodian for the original loan documents;

(C) An explanation of the duties and responsibilities of the seller, servicer, and all parties with respect to all aspects of the loans being purchased, including servicing, default, foreclosure, collection, and other matters involving the ongoing administration of the loans, if applicable; and

(D) The circumstances and conditions under which the parties to the agreement may replace the servicer when the seller retains the servicing rights for the loans being purchased, if applicable.

(v) Establish portfolio concentration limits by loan type and risk category in relation to net worth that are commensurate with the size, scope, and complexity of the credit union's loan purchases. The policy limits must take into account the potential impact of loan concentrations on the purchasing credit union's earnings, loan loss reserves, and net worth.

(vi) Address when a legal review of agreements or contracts will be performed to ensure that the legal and business interests of the credit union are protected against undue risk.

(c) * * *

(1) The board of directors or investment committee approves the sale;

(2) A written agreement, and a schedule of the eligible obligations covered by the agreement, is retained by the selling credit union that identifies the specific loans being sold either directly in the agreement or through a document that is incorporated by reference into the agreement; and

(3) A legal review of the written agreement is completed that includes the terms, recourse, and risk-sharing arrangements, and, as applicable, loan administration and controls, to ensure that the selling Federal credit union's legal and business interests are protected from undue risks.

(d) * * *

(1) * * *

(iii) A written agreement covering the pledging arrangement is retained by the credit union that pledges the eligible obligations.

* * * * *

(g) *Payments and compensation*— * * *

* * * * *

PART 714—LEASING

■ 5. The authority citation for part 714 continues to read as follows:

Authority: 12 U.S.C. 1756, 1757, 1766, 1785, 1789.

§ 714.9 [Removed and Reserved]

■ 6. Remove and reserve § 714.9.

[FR Doc. 2022–27607 Filed 12–29–22; 8:45 am]

BILLING CODE 7535–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[REG–114666–22]

RIN 1545–BQ50

Use of an Electronic Medium To Make Participant Elections and Spousal Consents

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of proposed rulemaking and notice of public hearing.

SUMMARY: This document sets forth a proposed regulation relating to the use of an electronic medium for participant elections and spousal consents. The proposed regulation provides an alternative to in-person witnessing of spousal consents required to be witnessed by a notary public or a plan representative, and clarifies that certain special rules for the use of an electronic medium for participant elections also apply to spousal consents. The proposed regulation generally affects sponsors and administrators of, and individuals entitled to benefits under, certain qualified retirement plans. This document also provides a notice of a public hearing.

DATES: Written or electronic comments must be received by March 30, 2023. A telephonic public hearing on this proposed regulation has been scheduled for April 11, 2023, at 10:00 a.m. ET. Requests to speak and outlines of topics to be discussed at the public hearing must be received by March 30, 2023. If no outlines are received by March 30, 2023, the public hearing will be cancelled. Requests to attend the public hearing must be received by 5:00 p.m. ET on April 7, 2023. The public hearing will be made accessible to people with disabilities. Requests for special assistance during the public hearing must be received by April 6, 2023.

ADDRESSES: Commenters are strongly encouraged to submit public comments electronically. Submit electronic submissions via the Federal eRulemaking Portal at *www.regulations.gov* (indicate IRS and REG–114666–22) by following the online instructions for submitting comments. Once submitted to the Federal eRulemaking Portal, comments cannot be edited or withdrawn. The Department of the Treasury (''Treasury Department'') and the IRS will publish for public availability any comment submitted electronically or on paper to its public docket on *www.regulations.gov*. Send paper submissions to: CC:PA:LPD:PR (REG–114666–22), Room 5203, Internal Revenue Service, P.O. Box 7604, Ben Franklin Station, Washington, DC 20044.

FOR FURTHER INFORMATION CONTACT: Concerning the regulation, call Arslan Malik at (202) 317–6700 or Pamela Kinard at (202) 317–6000; concerning submission of comments, the hearing, and the access code to attend the hearing by telephone, call Vivian Hayes at (202) 317–5306 (not toll-free numbers) or email *publichearings@irs.gov* (preferred).

SUPPLEMENTARY INFORMATION:

Background

A. In General

This document sets forth proposed amendments to 26 CFR part 1 under section 401 of the Internal Revenue Code (Code). Final regulations relating to the electronic delivery of applicable notices and participant elections were published in the **Federal Register** on October 20, 2006 (71 FR 61877) (2006 final regulations). The 2006 final regulations included new § 1.401(a)–21 setting forth standards for the use of an electronic medium to provide applicable notices to recipients or to make participant elections, amended Q&A–13 of § 54.4980F–1 by revising the rules for using an electronic method to provide a section 204(h) notice, and made certain conforming amendments.[1] Section 1.401(a)–21 reflects the applicable provisions of the Electronic Signatures in Global and National Commerce Act, Public Law 106–229, 114 Stat. 464 (2000) (E–SIGN), as it relates to the electronic delivery of applicable notices and participant elections. For an in-depth description of the provisions of E–SIGN, see the background section in the preamble of the 2006 final regulations.

B. Special Rules for Participant Elections

Section 1.401(a)–21(d) sets forth several special rules relating to the use of an electronic medium to make a participant election, which is defined in § 1.401(a)–21(e)(6) as any consent, election, request, agreement, or similar communication made by or from a participant, beneficiary, alternate payee, or an individual entitled to benefits under a retirement plan, employee benefit arrangement, or individual retirement plan. First, the person eligible to make a participant election must be effectively able to access the electronic medium used to make the participant election. Second, the electronic system used in making a participant election must be reasonably designed to preclude any person other than the appropriate person from making the participant election. Third, the electronic system must provide the person making the participant election with a reasonable opportunity to review, confirm, modify, or rescind the terms of the election before it becomes effective. Fourth, the person making the participant election must receive, within a reasonable time, confirmation of the effect of the election through either a written paper document or an electronic medium under a system that satisfies the applicable notice requirements under § 1.401(a)–21(b) or (c).

Spousal consent rules apply to plans that are subject to the qualified joint and survivor annuity (QJSA) and qualified preretirement survivor annuity (QPSA) requirements of section 417.[2] In general, these spousal consent rules require that a participant's spouse consent to the participant's election to take certain plan distributions or loans, and that such consent be witnessed by a plan representative or a notary public. See generally section 417(a)(2); § 1.401(a)–20, Q&A–8(b) and Q&A–24; and § 1.417(e)–1(b). Section 1.401(a)–21(d)(6)(i) provides that, in the case of a participant election that is required to be witnessed by a plan representative or a notary public (such as a spousal consent under section 417), the signature of the individual making the participant election must be witnessed in the physical presence of a plan representative or a notary public (physical presence requirement). Section 1.401(a)–21(d)(6)(ii) provides that, if the signature of an individual is witnessed in the physical presence of a notary public, an electronic notarization acknowledging the signature (in accordance with section 101(g) of E–SIGN,[3] and applicable State law for notaries public) will not be denied legal effect.

Section 1.401(a)–21(d)(6)(iii) provides that the Commissioner may provide in guidance published in the Internal Revenue Bulletin that the use of procedures under an electronic system is deemed to satisfy the physical presence requirement, but only if those procedures with respect to the electronic system provide the same safeguards for participant elections as are provided through the physical presence requirement.

C. Notices Issued in Response to COVID–19 Pandemic

During the Coronavirus Disease 2019 (COVID–19) pandemic,[4] the Treasury Department and the IRS received several requests from stakeholders to permit remote witnessing of spousal consents by a notary public or a plan representative over the internet using digital tools and live audio-video technologies (remote witnessing) for plan distributions and loans. These stakeholders stated that, due to social distancing requirements and other measures put into place in response to the COVID–19 pandemic, the physical presence requirement in § 1.401(a)–21(d)(6) made it difficult, if not impossible, for a participant to receive a plan distribution or loan for which spousal consent was required. In response to the COVID–19 pandemic and requests for relief from stakeholders, the Treasury Department and the IRS issued a notice granting temporary relief from the physical presence requirement for spousal consents and, in response to the continuing COVID–19 pandemic and additional requests for relief from stakeholders, three additional notices granting extensions of the temporary relief (together, the temporary relief notices).[5] The temporary relief notices granted relief for the period January 1, 2020, through December 31, 2022.

Under the temporary relief notices, in the case of a participant election witnessed by a notary public, an electronic system that uses remote witnessing is deemed to satisfy the physical presence requirement if the participant election is executed via live audio-video technology that otherwise satisfies the requirement for participant elections and is consistent with State law requirements that apply to the notary public.

In the case of a participant election witnessed by a plan representative, under the temporary relief notices, an electronic system that uses remote witnessing is deemed to satisfy the

[1] The 2006 final regulations made conforming amendments to §§ 1.72(p)–1, 1.132–9, 1.401(k)–3, 1.402(f)–1, 1.411(a)–11, 1.417(a)(3)–1, 1.7476–2, and 35.3405–1.

[2] In general, the spousal consent requirements under section 417 apply to a subset of qualified retirement plans, including defined benefit plans, money purchase pension plans, and defined contribution plans that (1) do not provide 100 percent death benefits for surviving spouses, (2) provide benefits in the form of a life annuity, or (3) are direct or indirect transferees of a defined benefit or money purchase pension plan. See section 401(a)(11)(B) and § 1.401(a)–20, Q&A–3. Section 205 of the Employee Retirement Income Security Act of 1974, as amended (ERISA), provides parallel annuity and spousal rights provisions, including spousal consent requirements. The IRS has interpretive authority over section 205 of ERISA pursuant to the Reorganization Plan No. 4 of 1978, 5 U.S.C. App.

[3] Section 101(g) of E–SIGN provides that ''[i]f a statute, regulation, or other rule of law requires a signature or record relating to a transaction in or affecting interstate or foreign commerce to be notarized, acknowledged, verified, or made under oath, that requirement is satisfied if the electronic signature of the person authorized to perform those acts, together with all other information required to be included by other applicable statute, regulation, or rule of law, is attached to or logically associated with the signature or record.''

[4] On March 13, 2020, the President determined that the COVID–19 pandemic was of sufficient severity and magnitude to warrant an emergency determination beginning March 1, 2020, under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5207.

[5] See Notice 2020–42, 2020–26 IRB 986; Notice 2021–03, 2021–2 IRB 316; Notice 2021–40, 2021–28 IRB 15; and Notice 2022–27, 2022–22 IRB 1151.

physical presence requirement if the electronic system uses live audio-video technology and satisfies the following requirements: (1) the individual signing the participant election must present a valid photo ID to the plan representative during the live audio-video conference, and may not merely transmit a copy of the photo ID prior to or after the witnessing; (2) the live audio-video conference must allow for direct interaction between the individual and the plan representative (for example, a pre-recorded video of the person signing is not sufficient); (3) the individual must transmit by fax or electronic means a legible copy of the signed document directly to the plan representative on the same date it was signed; and (4) after receiving the signed document, the plan representative must acknowledge that the signature has been witnessed by the plan representative in accordance with the requirements of the temporary relief notices and transmit the signed document, including the acknowledgement, back to the individual under a system that satisfies the applicable notice requirements under § 1.401(a)–21(c).

D. Comments Relating to Remote Witnessing of Spousal Consents

1. Solicitation of Public Comments

Several stakeholders requesting an extension of the temporary relief provided in Notice 2020–42 further requested that the relief be made permanent. In response, Notices 2021–03 and 2021–40 solicited comments relating to remote witnessing. Notice 2021–03 solicited comments on whether relief from the physical presence requirement should be made permanent and, if made permanent, what, if any, procedural safeguards would be necessary to reduce the risk of fraud, spousal coercion, or other abuse in the absence of a physical presence requirement. Notice 2021–03 also stated that any permanent modification to the physical presence requirement would be made through the regulatory process, giving stakeholders an opportunity to provide additional comments.

Notice 2021–40 solicited general and specific comments on whether permanent guidance modifying the physical presence requirement should be issued. Specifically, the Treasury Department and the IRS requested comments regarding: (1) how the temporary removal of the physical presence requirement for participant elections required to be witnessed by a plan representative or a notary public has affected costs and burdens for all parties (for example, participants, spouses, and plans) and whether there are costs and burdens associated with the physical presence requirement that support modifying the requirement on a permanent basis; (2) whether there is evidence that the temporary removal of the physical presence requirement has resulted in fraud, spousal coercion, or other abuse, and how, if the physical presence requirement is permanently modified, increased fraud, spousal coercion, or other abuse may be likely to result from that modification; (3) how participant elections are being witnessed, or are expected to be witnessed, as the COVID–19 pandemic abates (for example, whether the availability of in-person notarization has returned, or is expected to return, to pre-COVID–19 pandemic levels); (4) if guidance permanently modifying the physical presence requirement is issued, what procedures should be established to provide the same safeguards for participant elections as are provided through the physical presence requirement; and (5) if guidance permanently modifying the physical presence requirement is issued, whether the guidance should establish procedures for witnessing by plan representatives that are different from procedures for witnessing by notaries public.

2. Commenters Supporting Remote Witnessing

Commenters supporting remote witnessing for spousal consents made several arguments in support of adding remote witnessing as a permanent alternative to the physical presence requirement. Supporters argued that the remote witnessing process, in particular remote witnessing by a notary public, is easy to use, reduces the time it takes to process a distribution, and saves participants and beneficiaries both time and money.[6] For example, two commenters stated that remote witnessing by a notary public takes about 8 minutes on average. In addition, supporters argued that remote witnessing provides a necessary alternative for participants and spouses with mobility challenges, health concerns, and long commute times.

In response to concerns about potential fraud, supporters of remote witnessing for spousal consents argued that State notarization laws allowing remote witnessing have strict guidelines to help prevent fraudulent activity, including knowledge-based authentication and credential analysis. Supporters also noted that, during the period of remote witnessing permitted by the temporary relief notices, plans had not reported any evidence of fraud, spousal coercion, or other abuse.

In addressing whether additional safeguards should be added to the requirements for remote witnessing of spousal consents, supporters of remote witnessing generally argued that the safeguards provided in the temporary relief notices are adequate. They also pointed out that technological advances (such as real-time ID verification, electronic authentication standards, and digital recording and storage) have the potential to make the remote witnessing process more secure than the in-person witnessing process.

Some supporters of remote witnessing of spousal consents argued against establishing procedures for remote witnessing by a plan representative that differ from the procedures for a notary public. However, others argued that separate rules may be warranted because a plan representative (unlike a notary public) is not subject to any State oversight or mandated procedures for witnessing. One commenter suggested requiring that plan representatives use secure two-way live audio-video communication, record the audio-video communication, and store the audio-video recording.

Many supporters of remote witnessing of spousal consents supported a rule preventing a plan from requiring remote witnessing for spousal consents. They argued that a spouse should be able to choose to have a spousal consent witnessed in person, even if the plan permits remote witnessing.

Finally, one supporter of remote witnessing of spousal consents suggested clarification that the protections for participant elections made with an electronic medium set forth in § 1.401(a)–21(d) also apply to spousal elections made with an electronic medium. For example, the commenter suggested requiring that the system be designed to preclude anyone other than a spouse from giving consent and that a spouse be given a reasonable opportunity to review, confirm, modify, or rescind a spousal consent before it becomes effective.

[6] Another commenter addressed fees, stating that fees are imposed for both remote and in-person notarizations, are regulated by State law, and are generally equivalent. However, another commenter supporting remote witnessing argued that fees for remote witnessing by a notary public are generally higher than for in-person notarization, so that there is a cost associated with remote witnessing by a notary public. In addition, a commenter opposing remote witnessing argued that in-person notarization is usually free or has nominal fees, as compared to generally higher fees for remote witnessing by a notary public.

3. Commenters Opposing Remote Witnessing

Commenters opposing remote witnessing for spousal consents made several arguments in favor of retaining the physical presence requirement without modification. In particular, they argued that there is no longer a public health emergency justification for waiving the physical presence requirement, that the temporary relief notices were a temporary measure to address a national public health emergency, and that social distancing requirements and other measures have eased, so there is no longer a sufficient rationale for changing the physical presence requirement.

In addition, in response to statements by commenters that there has been no evidence of fraud during the period of the temporary relief granted under the temporary relief notices, opponents of remote witnessing for spousal consents argued that it usually takes many years for evidence of fraud to surface and that investigating and resolving allegations of fraud can take years. Opponents of remote witnessing also argued that a notary public or plan representative witnessing a spousal consent remotely, unlike a notary public or plan representative witnessing a spousal consent in-person, cannot check for signs of ID tampering or physically inspect ID security features intended to prevent forgeries. They further argued that knowledge-based authentication is not effective for a married couple because spouses are likely to know key facts about each other. With respect to detecting spousal coercion and pressure, opponents of remote witnessing of spousal consents argued that remote witnessing is inferior to in-person witnessing. For example, a commenter argued that a webcam's field of vision is narrow and cannot see individuals outside the field of vision who may be exerting undue influence on a spouse signing a consent. Opponents of remote witnessing for spousal consents noted that a conflict of interest may exist between spouses over the form and timing of retirement distributions and loans, so that a participant may put significant pressure on a spouse to waive spousal rights.

In addressing whether additional safeguards should be added to the requirements for remote witnessing of spousal consents in the temporary relief notices, opponents of remote witnessing for spousal consents argued that, if remote witnessing were permitted, the scope of the current safeguards in § 1.401(a)–21(d) should be clarified. For example, plans should be required to—(1) send to a spouse who provides spousal consent certain documents, such as a confirmation of the consent (separate from documents sent to a participant) in a manner that ensures actual receipt, (2) make a visual recording of the consent process, and (3) retain all critical plan records with respect to a participant election or spousal consent. They also suggested that the Treasury Department and the IRS impose additional protections, such as requiring that plans allow spouses to choose to have a spousal consent witnessed in person and providing guidance on post-consent confirmations.

Explanation of Provisions

A. Overview

The proposed regulation modifies the participant election rules in § 1.401(a)–21(d) in two significant ways. First, the proposed regulation sets forth alternatives to the physical presence requirement in § 1.401(a)–21(d)(6) for the witnessing of a spousal consent. These alternatives permit a spousal consent to be witnessed remotely by a notary public or plan representative, but only if certain conditions are satisfied. Second, the proposed regulation clarifies that the protections in § 1.401(a)–21(d) that apply to participant elections made using an electronic medium also apply to spousal consents made using an electronic medium. As part of that clarification, the proposed regulation modifies existing *Example 3* in § 1.401(a)–21(f), which illustrates the electronic transmission of a participant election for a plan loan and related notarized spousal consent, to clarify that the protections in § 1.401(a)–21(d) apply to the spousal consent. The proposed regulation also makes other minor conforming changes.

B. Remote Witnessing of Spousal Consents

Section 1.401(a)–21(d)(6)(i) of the proposed regulation generally retains the physical presence requirement set forth in the existing regulation. The physical presence requirement provides that, in the case of a spousal consent that is required to be witnessed by a notary public or a plan representative (such as a spousal consent under section 417), the signature of the person signing the spousal consent must be witnessed in the physical presence of a notary public or plan representative.

However, the proposed regulation also provides two alternatives to the physical presence requirement for spousal consents. These two alternatives are similar to the alternatives in the temporary relief notices issued in response to the COVID–19 pandemic. For more information about the temporary relief notices, see Part C in the Background section of this preamble, under the heading *Notices Issued in Response to COVID–19 Pandemic.*

1. Remote Witnessing by Notary Public

Proposed § 1.401(a)–21(d)(6)(ii)(A) sets forth remote witnessing rules for spousal consents witnessed by a notary public. The proposed regulation provides that, as an alternative to satisfying the physical presence requirement, a plan may accept a spousal consent witnessed remotely by a notary public, provided that (1) the signature of the person signing the spousal consent is witnessed by the notary public using live audio-video technology, (2) the requirements in § 1.401(a)–21(d) for spousal consents are satisfied, and (3) the remote witnessing is consistent with State law requirements that apply to the notary public. This alternative is substantially similar to the temporary relief from the physical presence requirement provided in the temporary relief notices for remote witnessing by a notary public.

Section 1.401(a)–21(d)(6)(ii)(A)(*2*) of the proposed regulation requires that a plan that accepts spousal consents witnessed remotely by a notary public, as described in proposed § 1.401(a)–21(d)(6)(ii)(A)(*1*), must also accept spousal consents witnessed in the physical presence of a notary public. Both supporters and opponents of remote witnessing suggested this requirement (which was also included in the temporary relief notices providing extensions).

2. Remote Witnessing by Plan Representative

The proposed regulation also sets forth remote witnessing rules for spousal consents witnessed by a plan representative. Proposed § 1.401(a)–21(d)(6)(ii)(B) provides that, as an alternative to satisfying the physical presence requirement, a plan may accept a spousal consent witnessed remotely by a plan representative, provided that (1) the signature of the person signing the spousal consent is witnessed by a plan representative using live audio-video technology, (2) the requirements in § 1.401(a)–21(d) for spousal consents are satisfied, and (3) the remote witnessing satisfies the following five requirements described in proposed § 1.401(a)–21(d)(6)(ii)(B)(*1*) through (*5*):

First, the person signing the spousal consent must present a valid photo ID to the plan representative during the live audio-video conference. For example, the person signing the spousal consent may not merely transmit a copy of the photo ID to the plan representative prior to or after the witnessing. Second, the live audio-video conference must allow for direct interaction between the person signing the spousal consent and the plan representative. A pre-recorded video of the person signing the spousal consent does not satisfy this requirement. Third, the person signing the spousal consent must transmit by electronic means a legible copy of the signed document directly to the plan representative on the same date that the spousal consent is signed. Fourth, after receiving the signed spousal consent, the plan representative must acknowledge that the signature has been witnessed by the plan representative and transmit the signed spousal consent, including the acknowledgement, back to the person signing the spousal consent under a system that satisfies the applicable notice requirements in § 1.401(a)–21(c). Fifth, a recording of the audio-video conference during which the spousal consent was signed remotely must be made by the plan representative and, consistent with § 1.401(a)–21(a)(3)(ii),[7] must be retained by the plan in accordance with section 6001 (which provides rules relating to the maintenance of records, statements, and special returns). The first four requirements are similar to the requirements in the temporary relief notices, and the fifth requirement is an additional requirement suggested by commenters both supporting and opposing remote witnessing.

Section 1.401(a)–21(d)(6)(iii) of the proposed regulation continues to include rules that are in the existing regulation relating to electronic notarization. In particular, the proposed regulation provides that, if the physical presence requirements (or the alternative remote witnessing requirements) are satisfied, an electronic notarization acknowledging a signature (in accordance with section 101(g) of E–SIGN and State law applicable to a notary public) will not be denied legal effect.

C. Clarifying That Existing Special Rules for Participant Elections Apply to Spousal Consents

The proposed regulation clarifies that the five special rules regarding use of an electronic medium in existing § 1.401(a)–21(d) apply to spousal consents. First, the electronic medium under an electronic system used to make a participant election or spousal consent must be a medium that the person who is eligible to make the election or consent is effectively able to access. Second, the electronic system used in making a participant election or spousal consent must be reasonably designed to preclude any person other than the appropriate person from making the participant election or spousal consent. Whether this condition is satisfied is based on facts and circumstances, including whether the participant election or spousal consent has the potential for a conflict of interest between the persons involved in the election or consent. Third, the electronic system used in making a participant election or spousal consent must provide the person making the election or consent with a reasonable opportunity to review, confirm, modify, or rescind the terms of the election or consent before it becomes effective. Fourth, the person making the participant election or spousal consent must receive, within a reasonable time, a confirmation of the effect of the election or consent through either a written paper document or an electronic medium under a system that satisfies the requirements of § 1.401(a)–21(b) or (c) (as if the confirmation were an applicable notice). Fifth, for spousal consents required to be witnessed by a plan representative or a notary public, the spousal consent must be witnessed in accordance with proposed § 1.401(a)–21(d)(6).

The requirements regarding use of an electronic medium in existing § 1.401(a)–21(d) apply to participant elections, and that term is defined broadly in § 1.401(a)–21(e)(6) to include any consent, election, request, agreement, or similar communication made by or from a participant, beneficiary, alternative payee, or an individual entitled to benefits. Under this broad definition, structured for simplicity, a participant election includes a spousal consent. However, in responding to the request for comments on whether to add spousal protections, commenters both supporting and opposing remote witnessing suggested explicitly applying the safeguards in § 1.401(a)–21(d) to spousal consents, including the safeguard that confirmation of the spousal consent be provided to the spouse. Although these safeguards already apply to spousal consents under existing § 1.401(a)–21(d), in response to these comments, the Treasury Department and the IRS believe that it is helpful to clarify and emphasize that these protections apply to spousal consents.

Accordingly, the proposed regulation includes three clarifications with respect to spousal consents. First, the proposed regulation provides a separate definition for spousal consent. Section 1.401(a)–21(e)(8) of the proposed regulation defines a spousal consent as a written consent signed by a participant's spouse that meets the requirements of section 417(a)(2)(A). Second, as described in the preceding paragraph, amendments are made in § 1.401(a)–21(d) to clarify that each special rule regarding use of an electronic medium for participant elections applies to spousal consents. Third, the proposed regulation modifies *Example 3* in § 1.401(a)–21(f) to clarify how the protections in § 1.401(a)–21(d) apply to spousal consents. *Example 3* in existing § 1.401(a)–21(f) illustrates the application of § 1.401(a)–21(d) to a participant election for a plan loan and a related notarized spousal consent. The example describes how a plan can satisfy the requirements in § 1.401(a)–21(d)(4) and (5), by providing the participant an opportunity to review the election and a confirmation of the election. However, the example is silent on how those requirements apply to the participant's spouse with respect to the spousal consent. The modified example addresses the application of those requirements with respect to the spousal consent.

The protections in § 1.401(a)–21(d) (as clarified by the proposed regulation), including the ability for a spouse to review and rescind a spousal consent, provide spouses using an electronic medium to sign a spousal consent (including the use of remote witnessing, whether by a notary public or a plan representative) with protections that are not provided to spouses who do not sign spousal consents using an electronic medium. Section 1.401(a)–20, Q&A–30, provides that, in general, a plan may preclude a spouse from revoking consent once it has been given, but that a participant must always be allowed to change an election during the applicable election period. However, as provided in existing § 1.401(a)–21(d) and clarified in this proposed regulation, § 1.401(a)–21(d)(4) requires a plan to give the spouse, for a spousal consent made

[7] Section 1.401(a)–21(a)(3)(ii) provides that the rules in the regulations do not alter the otherwise applicable requirements under the Code, such as the requirements relating to tax reporting, tax records, or substantiation of expenses, and refers to section 6001 for rules relating to the maintenance of records, statements, and special returns. It also refers to section 101(e) of E–SIGN, which provides that if an electronic record of an applicable notice or a participant election is not maintained in a form that is capable of being retained and accurately reproduced for later reference, then the legal effect, validity, or enforceability of the electronic record may be denied.

using an electronic medium that is subject to § 1.401(a)–21(d), a reasonable opportunity to review, confirm, modify, or rescind the terms of the spousal consent before it becomes effective.

D. Balancing of Interests

The Treasury Department and the IRS understand that there are strongly held points of view both in support of and in opposition to remote witnessing. As previously discussed in Part D of the Background section of this preamble, under the heading *Comments Relating to Remote Witnessing of Spousal Consents,* commenters supporting remote witnessing argued that remote witnessing provides a valuable option to participants and spouses (including those with limited mobility), by offering an essential convenience during a period in which more people rely on technological advances for their financial transactions. On the other hand, commenters opposing remote witnessing argued that spousal pension rights particularly affect retirement security for women and that any decision to waive those rights should be afforded maximum safeguards.[8]

In drafting the proposed regulation, the Treasury Department and the IRS have worked to strike a balance between the competing interests identified by commenters by offering remote witnessing as an option to those who elect to use it, but still requiring conditions on remote witnessing that are either similar to or more protective than the conditions in the temporary relief notices. Many of these conditions, including prohibiting a plan from requiring remote witnessing of spousal consents by a notary public and requiring that a plan representative record the audio-video conference during which a spousal consent is signed remotely (and retain the recording), were suggested both by commenters supporting and by commenters opposing remote witnessing.

In addition, the Treasury Department and the IRS believe that, by clarifying that the protections in § 1.401(a)–21(d) apply both to participant elections and spousal consents, the proposed regulation emphasizes several essential protections for a spouse using an electronic medium to sign a spousal consent. Those protections include requiring a plan to send a spouse confirmation of a spousal consent separate from the documents sent to the participant making the election and giving the spouse the ability to review and rescind the spousal consent.

[8] The Treasury Department and the IRS have provided sample language, in Notice 97–10, 1997–2 IRB 41, which is designed to make it easier for spouses of participants to understand their rights to survivor annuities under qualified plans. The language is designed to assist plan administrators in preparing spousal consent forms that meet the statutory requirements.

Proposed Applicability Date

This regulation is proposed to apply beginning on the date that is six months after publication of the Treasury decision adopting these rules as a final regulation in the **Federal Register**. Prior to the applicability date of the final regulation, taxpayers may rely on the rules set forth in this notice of proposed rulemaking.

Availability of IRS Documents

For copies of recently issued revenue procedures, revenue rulings, notices and other guidance published in the Internal Revenue Bulletin, please visit the IRS website at *www.irs.gov* or contact the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402.

Special Analyses

I. Regulatory Impact Analysis

This proposed regulation is not subject to review under section 6(b) of Executive Order 12866 pursuant to the Memorandum of Agreement (April 11, 2018) between the Treasury Department and the Office of Management and Budget regarding review of tax regulations.

II. Paperwork Reduction Act

The collections of information referenced in this proposed regulation were previously reviewed and approved by the Office of Management and Budget in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)) under control number 1545–1632.

Comments on the collection of information and the accuracy of estimated average annual burden and suggestions for reducing this burden should be sent to the Office of Management and Budget, Attn: Desk Officer for the Department of the Treasury, Office of Information and Regulatory Affairs, Washington, DC 20503, with copies to the Internal Revenue Service, Attn: IRS Reports Clearance Officer, SE:W:CAR:MP:T:T:SP; Washington, DC 20224. Comments on the collection of information should be received by March 30, 2023.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid control number assigned by the Office of Management and Budget.

Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

III. Regulatory Flexibility Act

Pursuant to the Regulatory Flexibility Act, it is hereby certified that this regulation will not have a significant economic impact on a substantial number of retirement plans, or their administrators and sponsors. This certification is based on several factors. First, the provisions of the proposed regulation that permit the remote witnessing of spousal consents are voluntary; plans are not required to permit remote witnessing, and spouses are not required to use remote witnessing even if a plan sponsor chooses to make remote witnessing available as an option under its plan. Accordingly, it is anticipated that a sponsor will permit remote witnessing under its plan only if the sponsor concludes that remote witnessing is more convenient and less burdensome for the plan and its participants and beneficiaries. Similarly, it is anticipated that a spouse in a plan that permits remote witnessing will use remote witnessing only if the spouse concludes that remote witnessing is more convenient and less burdensome. Further, the requirements for remote witnessing in the proposed regulation are substantially similar to requirements already imposed under the temporary relief notices, and the new requirements imposed under the proposed regulation with respect to witnessing by a plan representative (that is, that the plan must record the audio-video conference and retain the recording) were suggested by commenters (including commenters supporting remote witnessing).

Second, the provisions of the proposed regulation relating to the application of the requirements in § 1.401(a)–21(d) to spousal consents are merely clarifications of existing regulations. As previously stated, under existing § 1.401(a)–21, spousal consents are a subset of participant elections, so that the requirements in § 1.401(a)–21(d) apply to spousal consents. Thus, this proposed regulation does not impose new compliance burdens and is not expected to result in economically meaningful changes in behavior related to existing § 1.401(a)–21.

For the reasons stated, a regulatory flexibility analysis under the Regulatory

Flexibility Act is not required. The Treasury Department and the IRS invite comments on the impact of this regulation on small entities. Pursuant to section 7805(f) of the Code, this notice of proposed rulemaking has been submitted to the Chief Counsel of Advocacy of the Small Business Administration for comment on its impact on small business.

Comments and Public Hearing

Before these proposed amendments to the regulation are adopted as a final regulation, consideration will be given to comments that are submitted timely to the IRS as prescribed in the preamble under the **ADDRESSES** section. The Treasury Department and the IRS request comments on all aspects of the proposed regulation. Any electronic comments and paper comments submitted will be made available at *www.regulations.gov* or upon request.

A telephonic public hearing has been scheduled for April 11, 2023, beginning at 10 a.m. ET. The rules of 26 CFR 601.601(a)(3) apply to the hearing. Persons who wish to present oral comments by telephone at the public hearing must submit electronic or written comments and an outline of the topics to be addressed and the time to be devoted to each topic by March 30, 2023 as prescribed in the preamble under the **ADDRESSES** section. For those requesting to speak during the public hearing, send an outline of topic submissions electronically via the Federal eRulemaking Portal at *www.regulations.gov* (indicate IRS and REG–114666–22).

Individuals who want to testify (by telephone) at the public hearing must send an email to *publichearings@irs.gov* to receive the telephone number and access code for the public hearing. The subject line of the email must contain the regulation number REG–114666–22 and the word TESTIFY. For example, the subject line may say: Request to TESTIFY at Hearing for REG–114666–22. The email should include a copy of the speaker's public comments and outline of topics. Individuals who want to attend (by telephone) the public hearing must also send an email to *publichearings@irs.gov* to receive the telephone number and access code for the public hearing. The subject line of the email must contain the regulation number REG–114666–22 and the word ATTEND. For example, the subject line may say: Request to ATTEND Hearing for REG–114666–22. To request special assistance during the public hearing, contact the Publications and Regulations Branch of the Office of Associate Chief Counsel (Procedure and Administration) by sending an email to *publichearings@irs.gov* (preferred) or by telephone at (202) 317–5177 (not a toll-free number).

A period of 10 minutes will be allocated to each person for making comments. After the deadline for receiving outlines has passed, the IRS will prepare an agenda containing the schedule of speakers. Copies of the agenda will be made available at *www.regulations.gov,* search IRS and REG–114666–22. Copies of the agenda will also be available by emailing a request to *publichearings@irs.gov.* Please put ''REG–114666–22 Agenda Request'' in the subject line of the email.

Drafting Information

The principal authors of this regulation are Arslan Malik and Pamela Kinard, Office of Associate Chief Counsel (Employee Benefits, Exempt Organizations, and Employment Taxes (EEE)). However, other personnel from the IRS and the Treasury Department participated in the development of this regulation.

List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

Proposed Amendments to the Regulations

Accordingly, the Treasury Department and the IRS are proposing to amend 26 CFR part 1 as follows:

PART 1—INCOME TAXES

■ **Paragraph 1.** The authority citation for part 1 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 2.** Section 1.401(a)–21 is amended by:
■ 1. Revising the section heading;
■ 2. Revising the first sentence of paragraph (a)(1)(i) and the heading of paragraph (a)(1)(ii);
■ 3. Revising paragraphs (a)(1)(ii)(A) and (C);
■ 4. Revising paragraphs (a)(2)(i) and (ii);
■ 5. Revising the heading of paragraph (a)(2)(iii);
■ 6. Revising the last sentence of paragraph (a)(3)(i) and revising paragraph (a)(3)(ii);
■ 7. Revising the heading and first sentence of paragraph (a)(4);
■ 8. Revising paragraph (d);
■ 9. Revising paragraphs (e)(4) and (6) and adding paragraph (e)(8);
■ 10. In paragraph (f), designating *Examples 1* through *6* as paragraphs (f)(1) through (6), respectively;
■ 11. Revising newly designated paragraph (f)(3);
■ 12. Revising paragraph (g).

The revisions and addition read as follows:

§ 1.401(a)–21 Rules relating to the use of an electronic medium to provide applicable notices and to make participant elections and spousal consents.

(a) * * *

(1) * * *

(i) * * * This section provides rules relating to the use of an electronic medium to provide applicable notices and to make participant elections and spousal consents with respect to retirement plans, employee benefit arrangements, and individual retirement plans described in paragraph (a)(2) of this section. * * *

(ii) *Notices, elections, and consents required to be in writing or in written form*—(A) *In general.* The rules of this section must be satisfied for an electronic medium to be used to provide an applicable notice or make a participant election or spousal consent if the notice, election, or consent is required to be in writing or in written form under the Internal Revenue Code, Department of Treasury regulations, or other guidance published in the Internal Revenue Bulletin by the Commissioner.

* * * * *

(C) *Rules relating to participant elections and spousal consents.* A participant election or a spousal consent that is made using an electronic medium is treated as being provided in writing or in written form if the requirements of paragraphs (a)(5) and (d) of this section are satisfied.

* * * * *

(2) * * *

(i) *Notices, elections, or consents under retirement plans.* The rules of this section apply to any applicable notice, participant election, or spousal consent relating to the following retirement plans: a qualified retirement plan under sections 401(a) or 403(a); a section 403(b) plan; a simplified employee pension (SEP) under section 408(k); a simple retirement plan under section 408(p); or an eligible governmental plan under section 457(b).

(ii) *Notices or elections under other employee benefit arrangements.* The rules of this section also apply to any applicable notice or participant election relating to the following employee benefit arrangements: an accident and health plan or arrangement under sections 104(a)(3) and 105; a cafeteria plan under section 125; an educational assistance program under section 127; a qualified transportation fringe program under section 132; an Archer MSA under section 220; or a health savings account under section 223.

(iii) *Notices or elections under individual retirement plans.* * * *

(3) * * *

(i) * * * The rules in this section also do not apply to section 411(a)(3)(B) of the Code (relating to suspension of benefits), section 4980B(f)(6) (relating to an individual's COBRA rights), or any other Code provision over which the Department of Labor or Pension Benefit Guaranty Corporation has similar interpretative authority.

(ii) *Recordkeeping and other requirements.* The rules in this section apply only with respect to applicable notices, participant elections, and spousal consents relating to a person's rights under a retirement plan, an employee benefit arrangement, or an individual retirement plan. Thus, the rules in this section do not alter the otherwise applicable requirements under the Code, such as the requirements relating to tax reporting, tax records, or substantiation of expenses. See section 6001 for rules relating to the maintenance of records, statements, and special returns. See also section 101(e) of E–SIGN, which provides that if an electronic record of an applicable notice, a participant election, or a spousal consent is not maintained in a form that is capable of being retained and accurately reproduced for later reference, then the legal effect, validity, or enforceability of the electronic record may be denied.

(4) *General requirements related to applicable notices, participant elections, and spousal consents.* The rules of this section supplement the general requirements related to each applicable notice, participant election, and spousal consent. * * *

* * * * *

(d) *Special rules for participant elections and spousal consents*—(1) *In general.* This paragraph (d) is satisfied for participant elections or spousal consents if the conditions described in paragraphs (d)(2) through (6) of this section are satisfied.

(2) *Effective ability to access.* The electronic medium under an electronic system used to make a participant election or spousal consent must be a medium that the person who is eligible to make the election or consent is effectively able to access. If the appropriate person is not effectively able to access the electronic medium for making the election or consent, the election or consent will not be treated as made available to that person. Thus, for example, the election will not be treated as made available for purposes of the rules under section 401(a)(4).

(3) *Authentication.* The electronic system used in making a participant election or spousal consent must be reasonably designed to preclude any person other than the appropriate person from making the election or consent. Whether this condition is satisfied is based on facts and circumstances, including whether the election or consent has the potential for a conflict of interest between the persons involved in the election or consent.

(4) *Opportunity to review.* The electronic system used in making a participant election or spousal consent must provide the person making the election or consent with a reasonable opportunity to review, confirm, modify, or rescind the terms of the election or consent before the election or consent becomes effective.

(5) *Confirmation of action.* The person making the participant election or spousal consent must receive, within a reasonable time, a confirmation of the effect of the election or the consent under the terms of the plan or arrangement through either a written paper document or an electronic medium under a system that satisfies the requirements of either paragraph (b) or (c) of this section (as if the confirmation were an applicable notice).

(6) *Spousal consents required under the Code to be witnessed by a notary public or a plan representative*—(i) *Witnessing of spousal consent in physical presence of notary public or plan representative.* Except as provided in paragraph (d)(6)(ii) of this section, in the case of a spousal consent that is required to be witnessed by a notary public or a plan representative (such as a spousal consent under section 417), the signature of the person signing the consent must be witnessed in the physical presence of a notary public or a plan representative.

(ii) *Alternative to witnessing of spousal consent in physical presence of notary public or plan representative*—(A) *Remote witnessing of spousal consent by notary public*—(*1*) *In general.* As an alternative to witnessing of a spousal consent in the physical presence of a notary public described in paragraph (d)(6)(i) of this section, a plan may accept a consent witnessed remotely by a notary public if the signature of the person signing the consent is witnessed by the notary public using live audio-video technology, the requirements of paragraph (d) of this section for consents are satisfied, and the remote witnessing is consistent with State law requirements that apply to the notary public.

(*2*) *In-person notarization must be accepted by plan.* A plan that accepts spousal consents witnessed remotely by a notary public must also accept consents witnessed in the physical presence of a notary public.

(B) *Remote witnessing of spousal consent by plan representative.* As an alternative to witnessing of a spousal consent in the physical presence of a plan representative described in paragraph (d)(6)(i) of this section, a plan may accept a consent witnessed remotely by a plan representative if the signature of the person signing the consent is witnessed by the plan representative using live audio-video technology, the requirements of paragraph (d) of this section are satisfied, and the additional requirements described in paragraphs (d)(6)(ii)(B)(*1*) through (*5*) of this section are satisfied.

(*1*) *Presentation of valid photo ID.* The person signing the spousal consent must present a valid photo ID to the plan representative during the live audio-video conference (for example, the person signing the consent may not merely transmit a copy of the photo ID to the plan representative prior to or after the witnessing).

(*2*) *Direct interaction.* The live audio-video conference must allow for direct interaction between the person signing the spousal consent and the plan representative (for example, a pre-recorded video of the person signing the consent is not sufficient).

(*3*) *Same-day document transmission.* The person signing the spousal consent must transmit by electronic means a legible copy of the signed document directly to the plan representative on the same date that the document is signed.

(*4*) *Plan representative acknowledgement.* After receiving the signed document, the plan representative must acknowledge that the signature has been witnessed by the plan representative in accordance with paragraph (d)(6)(ii)(B) of this section and transmit the signed document, including the acknowledgement, back to the person signing the spousal consent under a system that satisfies the applicable notice requirements in paragraph (c) of this section.

(*5*) *Recording and retention of audio-video conference.* A recording of the audio-video conference during which the spousal consent was signed remotely must be made by the plan representative and, consistent with paragraph (a)(3)(ii) of this section, must be retained by the plan in accordance with section 6001.

(iii) *Electronic notarization permitted.* If the requirements of paragraph (d)(6)(i) or (d)(6)(ii)(A) of this section are satisfied, an electronic notarization acknowledging a signature (in accordance with section 101(g) of E–SIGN and State law applicable to a notary public) will not be denied legal effect.

(e) * * *

(4) *Electronic record.* The term *electronic record* means an applicable notice, a participant election, or a spousal consent that is created, generated, sent, communicated, received, or stored by electronic media.

* * * * *

(6) *Participant election.* The term *participant election* includes any election, request, agreement, or similar communication made by or from a participant, beneficiary, alternate payee, or person entitled to benefits under a retirement plan, employee benefit arrangement, or individual retirement plan as described in paragraph (a)(2) of this section.

* * * * *

(8) *Spousal consent.* The term *spousal consent* means a written consent signed by a participant's spouse that meets the requirements of section 417(a)(2)(A).

(f) * * *

* * * * *

(3) *Example 3.* (i) *Facts involving participant election for plan loan and related notarized spousal consent.* Plan C, a qualified money purchase pension plan, permits a married participant to request a plan loan through Plan C's website with the notarized consent of the spouse. Under Plan C's system for requesting a plan loan, a participant must enter the participant's account number and personal identification number (PIN) (in order to preclude any person other than the participant from making the election) and the participant's email address. The information entered by the participant must match the information in Plan C's records in order for the transaction to proceed. Participant M, a married participant, is effectively able to access the website available to apply for a plan loan. Participant M completes the loan documents on Plan C's website.

(A) After receiving the completed loan documents, Plan C notifies Participant M that Participant M's spouse must sign a spousal consent for the plan loan that is witnessed by a notary public or plan representative. The spousal consent form includes sections for the signature, email address, and mailing address of Participant M's spouse. Participant M's spouse signs the spousal consent for the plan loan, and the signature is witnessed in the physical presence of a notary public. Participant M's spouse provides the notarized spousal consent to Participant M, and Participant M scans the notarized spousal consent and uploads it to Plan C's website.

(B) After Plan C receives the spousal consent, Plan C sends an email to Participant M with attached loan documents, giving Participant M a reasonable period of time to review and confirm the loan documents and to determine whether the plan loan should be modified (such as editing the account number or decreasing the loan amount) or rescinded. Using the email address provided on the spousal consent form, Plan C also sends an email to Participant M's spouse that attaches the signed spousal consent and gives Participant M's spouse a specified reasonable period of time to review and confirm the spousal consent and to determine whether the spousal consent should be modified or rescinded. The email also notifies Participant M's spouse that Participant M's spouse may request a written paper copy of the signed spousal consent and that, if Participant M's spouse requests a written paper copy of the signed spousal consent, it will be provided at no extra charge.

(C) Participant M makes no changes to the loan documents, and Participant M's spouse makes no changes to the spousal consent. After Plan C processes the loan documents, including the notarized spousal consent, Plan C notifies Participant M that the loan documents have been processed. In addition, the notice provides that Participant M may request a written paper copy of the loan documents and that, if Participant M requests a written paper copy of the loan documents, it will be provided at no charge. Plan C retains an electronic copy of the loan documents, including the notarized spousal consent, in a form that is capable of being retained and accurately reproduced for later reference by all parties.

(ii) *Conclusion.* In this paragraph (f)(3) (*Example 3*), the electronic transmission of the participant election for a plan loan and related notarized spousal consent satisfies the requirements of paragraphs (a), (c), and (d) of this section.

* * * * *

(g) *Applicability date*—(1) *In general.* Except as otherwise provided in paragraph (g)(2) of this section, the rules provided in this section apply to applicable notices provided and to participant elections and spousal consents made on or after (the date that is six months after the final regulation is published in the **Federal Register**).

(2) *Special applicability date rules for periods before the general applicability date.* Section 1.401(a)–21, as it appeared in the April 1, 2022, edition of 26 CFR part 1, applies for periods before the general applicability date in paragraph (g)(1) of this section.

Melanie R. Krause,

Acting Deputy Commissioner for Services and Enforcement.

[FR Doc. 2022–28327 Filed 12–29–22; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R05–OAR–2018–0841; FRL–10489–01–R5]

Air Plan Approval; Illinois; Alton Township 2010 SO_2 Attainment Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve the State Implementation Plan (SIP) revision which Illinois submitted to EPA on December 31, 2018, for attaining the 2010 sulfur dioxide (SO_2) primary national ambient air quality standard (NAAQS) for the Alton Township nonattainment area in Madison County. This plan (herein called a ''nonattainment plan'') includes Illinois' attainment demonstration and other elements required under the Clean Air Act (CAA), including the requirement for meeting reasonable further progress (RFP) toward attainment of the NAAQS, reasonably available control measures and reasonably available control technology (RACM/RACT), base-year and projection-year emission inventories, enforceable emission limitations and control measures, nonattainment new source review (NNSR), and contingency measures. EPA is proposing to approve Illinois' submission as a SIP revision for attaining the 2010 primary SO_2 NAAQS in the Alton township nonattainment area, finding that Illinois has adequately demonstrated that the plan provisions provide for attainment of NAAQS in the nonattainment area and that the plan meets the other applicable requirements under the CAA.

DATES: Comments must be received on or before January 30, 2023.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R05–OAR–2018–0841 at *https://www.regulations.gov,* or via email to *arra.sarah@epa.gov.* For comments submitted at *Regulations.gov*, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. For either manner of submission, EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www2.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT:

Andrew Lee, Physical Scientist, Attainment Planning and Maintenance Section, Air Programs Branch (AR–18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 353–7645, *lee.andrew.c@epa.gov.* The EPA Region 5 office is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays and facility closures due to COVID–19.

SUPPLEMENTARY INFORMATION:

Throughout this document whenever ''we,'' ''us,'' or ''our'' is used, we mean EPA.

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I. Why was Illinois required to submit an SO_2 plan for the Alton township area?

On June 22, 2010, EPA published a new 1-hour primary SO_2 NAAQS of 75 parts per billion (ppb), which is met at an ambient air quality monitoring site when the 3-year average of the annual 99th percentile of daily maximum 1-hour average concentrations does not exceed 75 ppb, as determined in accordance with appendix T of 40 CFR part 50. *See* 75 FR 35520, codified at 40 CFR 50.17(a)–(b). EPA has promulgated designations for this standard in four rounds. Alton Township, Illinois was designated nonattainment by EPA on June 30, 2016, as part of the Agency's Round 2 designations.

In the Round 2 designations, EPA designated areas including power plants exceeding certain emissions criteria, specifically including the Wood River power plant located in Wood River, Illinois. The modeling that Illinois submitted in support of its Round 2 designations recommendations included both the Wood River power plant and an additional source, the Alton Steel, Inc. steel mill in Alton, Illinois (Alton Steel). Alton Steel was included in the modeling analysis because its SO_2 emissions showed the potential for creating significant SO_2 concentration gradients within the modeling domain. The modeling was done using the AERMOD air dispersion modeling software utilizing data based on actual emissions from the Wood River Power Station and Alton Steel.

The state found that the highest modeled NAAQS violations in the area were almost entirely due to Alton Steel emissions and especially occurred along or near Alton Steel's north fence line. The Alton Steel facility consists of a melt shop and a rolling mill in which steel scrap is melted (electric arc furnace), refined/alloyed (ladle metallurgical furnace), and then cast/formed into blooms and slabs. Illinois provided suitable evidence that Wood River should be judged not to contribute to the modeled violation as the facility was shut down in 2016. As such, Illinois recommended the designation of nonattainment for Alton Township to focus on the NAAQS violations caused by Alton Steel.

The state's modeling in support of its designation recommendation indicated that the predicted 99th percentile 1-hour average concentration within the chosen modeling domain was 456.40 micrograms per cubic meter (μg/m^3), or 174.2 ppb. This modeled concentration included the background concentration of SO_2 and was based on actual emissions from the facilities in the area. Illinois performed a culpability analysis which demonstrated that only a small group of receptors violated the 2010 SO_2 NAAQS, and these receptors were primarily affected by emissions from Alton Steel, which were greatly influenced by downwash. High concentrations near Alton Steel were a consequence of building downwash combined with downward pointing vents, and primarily occurred when winds were blowing from the southwest, a direction that maximized the impact of the Alton Steel building in causing downwash and downwash-influenced concentrations in nearby ambient air locations.

On September 18, 2015, Illinois submitted its recommendations for EPA to designate certain areas of the state as part of the Round 2 designations. In its submission, Illinois recommended that a portion of Madison County be designated as nonattainment for the 2010 SO_2 NAAQS—specifically, a portion of southern Alton Township. EPA, agreeing with Illinois' analysis of the area, concurred with the state's proposed finding of nonattainment for Alton Township. EPA published a final action designating the area as nonattainment on July 12, 2016 (81 FR 45039), which became effective September 12, 2016. In response to EPA's designation of the Alton Township area, Illinois submitted an attainment plan on December 13, 2018, to EPA for approval. Under CAA section 192(a), these plans are required to demonstrate that their respective areas will attain the NAAQS as expeditiously as practicable, but no later than five years from the effective date of designation, which was September 12, 2021.

Unlike in the Round 2 designations modeling, the Alton Township attainment demonstration does not include the Wood River Power Station among the sources modeled. Wood River was excluded from the nonattainment area because in November 2015, the facility owner (Dynegy, Inc.) publicly announced that the power plant would be closing, pending approval of the electrical transmission system operator (Midcontinent Independent System Operator). The facility was retired in June 2016 and ceased emitting SO_2 at that point, and was demolished in February 2021.

II. Requirements for SO_2 Nonattainment Area Plans

Nonattainment area SO_2 SIPs must meet the applicable requirements of the CAA, and specifically CAA sections 110, 172, 191 and 192. EPA's regulations governing nonattainment area SIPs are set forth at 40 CFR part 51, with specific procedural requirements and control strategy requirements residing at subparts F and G, respectively. Soon after Congress enacted the 1990 amendments to the CAA, EPA issued comprehensive guidance on SIPs in a document entitled the ''General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990,'' published at 57 FR 13498 (April 16, 1992) (General Preamble). Among other things, the General Preamble addressed SO_2 SIPs and fundamental principles for SIP control strategies. *Id.* at 13545–49, 13567–68. On April 23, 2014, EPA issued guidance and recommendations for meeting the statutory requirements in SO_2 SIPs addressing the 2010 primary NAAQS, in a document entitled, ''Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions'' (April 2014 guidance), available at *https://www.epa.gov/sites/production/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.* In the April 2014 guidance, EPA described the statutory requirements for a complete nonattainment area SIP, which includes an accurate emissions inventory of current emissions for all sources of SO_2 within the nonattainment area; an attainment demonstration; enforceable emissions limitations and control measures; demonstration of RFP; implementation of RACM (including RACT); NNSR; and adequate contingency measures for the affected area.

In order for EPA to fully approve a SIP as meeting the requirements of CAA sections 110, 172 and 191–192 and EPA's regulations at 40 CFR part 51, the SIP for the affected area needs to demonstrate to EPA's satisfaction that each of the aforementioned requirements have been met. Under CAA sections 110(l) and 193, EPA may not approve a SIP that would interfere with any applicable requirement concerning NAAQS attainment and RFP, or any other applicable requirement, and no requirement in effect (or required to be adopted by an order, settlement, agreement, or plan in effect before November 15, 1990), in any area which is a nonattainment area for any air pollutant, may be modified in any manner unless it ensures equivalent or greater emission reductions of such air pollutant.

III. Attainment Demonstration and Longer-Term Averaging

CAA section 172(c)(1) directs states with areas designated as nonattainment to demonstrate that the submitted plan provides for attainment of the NAAQS. 40 CFR part 51, subpart G further delineates the control strategy requirements that SIPs must meet, and EPA has long required that all SIPs and control strategies reflect the four fundamental principles of quantification, enforceability, replicability, and accountability. *See* General Preamble, at 13567–68. SO_2 attainment plans must consist of two components: (1) emission limits and other control measures that assure implementation of permanent, enforceable and necessary emission controls, and (2) a modeling analysis which meets the requirements of 40 CFR part 51, appendix W which demonstrates that these emission limits and control measures provide for timely attainment of the primary SO_2 NAAQS as expeditiously as practicable, but by no later than the attainment date for the affected area. In all cases, the emission limits and control measures must be accompanied by appropriate methods and conditions to determine compliance with the respective emission limits and control measures, and must be quantifiable (*i.e.,* a specific amount of emission reduction can be ascribed to the measures), fully enforceable (specifying clear, unambiguous and measurable requirements for which compliance can be practicably determined), replicable (the procedures for determining compliance are sufficiently specific and non-subjective so that two independent entities applying the procedures would obtain the same result), and accountable (source specific limits must be permanent and must reflect the assumptions used in the SIP demonstrations).

EPA's April 2014 guidance recommends that the emission limits be expressed as short-term average limits (*e.g.,* addressing emissions averaged over one or three hours), but also allows for emission limits with longer averaging times of up to 30 days so long as the state meets various suggested criteria. *See* April 2014 guidance, pp. 22 to 39. The guidance recommends that, should states and sources utilize a longer-term average limit, the limit should be set at an adjusted level that reflects a stringency comparable to the 1-hour critical emission value shown to provide for attainment that the plan otherwise could have set as a 1-hour emission limit.

Illinois' plan applies 1-hour average emission limits to Alton Steel. However, Illinois' plan also considers the impact of an additional facility that is about 12 kilometers from Alton Steel, namely Ameren's Portage des Sioux Power Center (''Sioux'' or ''Ameren-Sioux'') in St. Charles County, Missouri, a facility that is subject to a 24-hour block average limit. Therefore, EPA is providing the following discussion of its rationale for approving the use of longer-term average limits in plans designed to provide for attainment.

The April 2014 guidance provides an extensive discussion of EPA's view that appropriately set comparably stringent limits based on averaging times as long as 30 days can be found to provide for attainment of the 2010 SO_2 NAAQS. In evaluating this option, EPA considered the nature of the standard, conducted detailed analyses of the impact of the use of 30-day average limits on the prospects for attaining the standard, and carefully reviewed how best to achieve an appropriate balance among the various factors that warrant consideration in judging whether a state's plan provides for attainment. *See id.; see also id.* at appendices B, C and D.

As specified in 40 CFR 50.17(b), the 1-hour primary SO_2 NAAQS is met at an ambient air quality monitoring site when the 3-year average of the annual 99th percentile of daily maximum 1-hour average concentrations is less than or equal to 75 ppb. In a year with 365 days of valid monitoring data, the 99th percentile would be the fourth highest daily maximum 1-hour value. The 2010 SO_2 NAAQS, including this form of determining compliance with the standard, was upheld by the U.S. Court of Appeals for the District of Columbia Circuit in *Nat'l Envt'l Dev. Ass'n's Clean Air Project* v. *EPA,* 686 F.3d 803 (D.C. Cir. 2012). Because the standard has this form, a single exceedance of the level of the NAAQS does not create a violation of the standard. Instead, at issue is whether a source operating in compliance with a properly set limit reflecting a longer-term average could cause hourly exceedances of the NAAQS level, and if so the resulting frequency and magnitude of such hourly exceedances, and in particular whether EPA can have reasonable confidence that a properly set longer-term average limit will provide that the 3-year average of the annual fourth highest daily maximum hourly value will be at or below 75 ppb. The following is a synopsis of EPA's review of how to judge whether such plans ''provide for attainment,'' based on modeling of projected allowable emissions and in light of the NAAQS' form for determining attainment at monitoring sites.

For plans for SO_2 based on 1-hour emission limits, the standard approach is to conduct modeling using fixed emission rates. The maximum emission rate that would be modeled to result in attainment (*i.e.,* in an ''average year'' [1] shows three, not four days with maximum hourly levels exceeding 75 ppb, over three consecutive years) is labeled the ''critical emission value.'' The modeling process for identifying this critical emission value inherently considers the numerous variables that affect ambient concentrations of SO_2, such as meteorological data, background concentrations, and topography. In the standard approach, the state would then provide for attainment by setting a continuously applicable 1-hour emission limit at this critical emission value. This is the approach Illinois took for setting limits at Alton Steel.

EPA recognizes that some sources have highly variable emissions, for example due to variations in fuel sulfur content and operating rate, that can make it extremely difficult, even with a well-designed control strategy, to ensure in practice that emissions for any given hour do not exceed the critical emissions value. EPA also acknowledges the concern that longer-term emission limits can allow short periods with emissions above the critical emissions value, which, if coincident with meteorological conditions conducive to high SO_2 concentrations, could in turn create the possibility of a NAAQS level exceedance occurring on a day when an exceedance would not have occurred if emissions were continuously controlled at the level corresponding to the critical emissions value. However, for several reasons, EPA believes that the approach recommended in its guidance document suitably addresses this concern. First, from a practical perspective, EPA expects the actual emission profile of a source subject to an appropriately set longer-term average limit to be like the emission profile of a source subject to an analogous 1-hour average limit. EPA expects this similarity because it has recommended that the longer-term average limit be set at a level that is comparably stringent to the otherwise applicable 1-hour limit (reflecting a downward adjustment from the critical emissions value) and that takes the source's emissions profile into account. As a result, EPA expects either form of emissions limit to yield comparable air quality.

Second, from a more theoretical perspective, EPA has compared the likely air quality with a source having maximum allowable emissions under an appropriately set longer-term limit, as compared to the likely air quality with the source having maximum allowable emissions under the comparable 1-hour limit. In this comparison, in the 1-hour average limit scenario, the source is presumed at all times to emit at the critical emissions level, and in the longer-term average limit scenario, the source is presumed occasionally to emit more than the critical emissions value but on average, and presumably at most times, to emit well below the critical emissions value. In an ''average year,'' compliance with the 1-hour limit is expected to result in three exceedance days (*i.e.,* three days with an hourly value above 75 ppb) and a fourth day with a maximum hourly value at 75 ppb. By comparison, with the source complying with a longer-term limit, it is possible that additional exceedances would occur that would not occur in the 1-hour limit scenario (if emissions exceed the critical emissions value at times when meteorology is conducive to poor air quality). However, this comparison must also factor in the likelihood that exceedances that would be expected in the 1-hour limit scenario would not occur in the longer-term limit scenario. This result arises because the longer-term limit requires lower emissions most of the time (because the limit is set well below the critical emissions value), so a source complying with an appropriately set longer term limit is likely to have lower emissions at critical times than would be the case if the source were emitting as allowed with a 1-hour limit.

As a hypothetical example to illustrate these points, suppose a source that always emits 1,000 pounds of SO_2 per hour, which results in air quality at the level of the NAAQS (*i.e.,* results in a design value of 75 ppb). Suppose further that in an ''average year,'' these emissions cause the 5 highest maximum daily average 1-hour concentrations to be 100 ppb, 90 ppb, 80 ppb, 75 ppb, and 70 ppb. Then suppose that the source becomes subject to a 30-day average emission limit of 700 pounds per hour. It is theoretically possible for a source meeting this limit to have emissions that occasionally exceed 1,000 pounds per hour, but with a typical emissions profile, emissions would much more commonly be between 600 and 800 pounds per hour. This simplified example assumes a zero-background concentration, which allows one to assume a linear relationship between emissions and air quality. (A nonzero background concentration would make the mathematics more difficult but would give similar results.) Air quality will depend on what emissions happen on what critical hours, but suppose that emissions at the relevant times on these 5 days are 800 pounds per hour, 1,100 pounds per hour, 500 pounds per hour, 900 pounds per hour, and 1,200 pounds per hour, respectively. (This is a conservative example because the average of these emissions, 900 pounds per hour, is well over the 30-day average emission limit.) These emissions would result in daily maximum 1-hour concentrations of 80 ppb, 99 ppb, 40 ppb, 67.5 ppb, and 84 ppb. In this example, the fifth day would have an exceedance that would not otherwise have occurred, but the third day would not have an exceedance that otherwise would have occurred, and the fourth day would have been below, rather than at, 75 ppb. In this example, the fourth highest maximum daily concentration under the 30-day average would be 67.5 ppb.

This simplified example encapsulates the findings of a more complicated statistical analysis that EPA conducted using a range of scenarios using actual plant data. As described in appendix B of EPA's April 2014 guidance, EPA found that the requirement for lower average emissions is highly likely to yield better air quality than is required with a comparably stringent 1-hour limit. Based on analyses described in appendix B of its 2014 guidance, EPA expects that an emissions profile with maximum allowable emissions under an appropriately set, comparably stringent 30-day average limit is likely to have the net effect of having a *lower* number of hourly exceedances of the NAAQS level and better air quality than an emission profile with maximum allowable emissions under a 1-hour emission limit at the critical emissions value.[2] This

[1] An ''average year'' is used to mean a year with average air quality. While 40 CFR 50 appendix T provides for averaging three years of 99th percentile daily maximum values (*e.g.,* the fourth highest maximum daily concentration in a year with 365 days with valid data), this discussion and an example below uses a single ''average year'' in order to simplify the illustration of relevant principles.

[2] See also further analyses described in rulemaking on the SO_2 nonattainment plan for Southwest Indiana. In response to comments expressing concern that the emissions profiles analyzed for appendix B represented actual rather than allowable emissions, EPA conducted additional work formulating sample allowable emission profiles and analyzing the resulting air quality impact. These analyses provided further support for the conclusion that an appropriately set longer term average emission limit in appropriate circumstances can suitably provide for attainment. The rulemaking describing these further analyses

result provides a compelling policy rationale for allowing the use of a longer averaging period, in appropriate circumstances where the facts indicate this result can be expected to occur.

The question then becomes whether this approach—which is likely to produce a lower number of overall hourly NAAQS level exceedances even though it may produce some unexpected exceedances above the critical emission value—meets the requirement in section 110(a)(1) and 172(c)(1) for state implementation plans to ''provide for attainment'' of the NAAQS. For SO_2, as for other pollutants, it is generally impossible to design a nonattainment plan in the present that will guarantee that attainment will occur in the future. A variety of factors can cause a well-designed attainment plan to fail and unexpectedly not result in attainment, for example if meteorology occurs that is more conducive to poor air quality than was anticipated in the plan. Therefore, in determining whether a plan meets the requirement to provide for attainment, EPA's task is commonly to judge not whether the plan provides absolute certainty that attainment will in fact occur, but rather whether the plan provides an adequate level of confidence of prospective NAAQS attainment. From this perspective, in evaluating use of a 30-day average limit, EPA must weigh the likely net effect on air quality. Such an evaluation must consider the risk that occasions with meteorology conducive to high concentrations will have elevated emissions leading to NAAQS level exceedances that would not otherwise have occurred and must also weigh the likelihood that the requirement for lower emissions on average will result in days not having hourly exceedances that would have been expected with emissions at the critical emissions value. Additional policy considerations, such as in this case the desirability of accommodating real world emissions variability without significant risk of NAAQS violations, are also appropriate factors for EPA to weigh in judging whether a plan provides a reasonable degree of confidence that the plan will lead to attainment. Based on these considerations, especially given the high likelihood that a continuously enforceable limit averaged over as long as 30 days, determined in accordance with EPA's guidance, will result in attainment, EPA believes as a general matter that such limits, if appropriately determined, can reasonably be considered to provide for attainment of the 2010 SO_2 NAAQS.

The April 2014 guidance offers specific recommendations for determining an appropriate longer-term average limit. The recommended method starts with determination of the 1-hour emission limit that would provide for attainment (*i.e.,* the critical emissions value), and applies an adjustment factor to determine the (lower) level of the longer-term average emission limit that would be estimated to have a stringency comparable to the otherwise necessary 1-hour emission limit. This method uses a database of continuous emission data reflecting the type of control that the source will be using to comply with the SIP emission limits, which (if compliance requires new controls) may require use of an emission database from another source. The recommended method involves using these data to compute a complete set of emission averages, computed according to the averaging time and averaging procedures of the prospective emissions limit. In this recommended method, the ratio of the 99th percentile among these long-term averages to the 99th percentile of the 1-hour values represents an adjustment factor that may be multiplied by the candidate 1-hour emission limit to determine a longer-term average emission limit that may be considered comparably stringent.[3] The guidance also addresses a variety of related topics, such as the potential utility of setting supplemental emission limits, such as mass-based limits, to reduce the likelihood and/or magnitude of elevated emission levels that might occur under the longer-term emission rate limit.

Preferred air quality models for use in regulatory applications are described in appendix A of EPA's *Guideline on Air Quality Models* (40 CFR part 51, appendix W). In 2005, EPA promulgated AERMOD as the Agency's preferred near-field dispersion modeling for a wide range of regulatory applications addressing stationary sources (for example in estimating SO_2 concentrations) in all types of terrain based on extensive developmental and performance evaluation. Supplemental guidance on modeling for purposes of demonstrating attainment of the SO_2 standard is provided in appendix A to the April 2014 guidance document referenced above. Appendix A provides extensive guidance on the modeling domain, the source inputs, assorted types of meteorological data, and background concentrations. Consistency with the recommendations in this guidance is generally necessary for the attainment demonstration to offer adequately reliable assurance that the plan provides for attainment.

As stated previously, attainment demonstrations for the 2010 1-hour primary SO_2 NAAQS must demonstrate future attainment and maintenance of the NAAQS in the entire area designated as nonattainment (*i.e.,* not just at the violating monitor) by using air quality dispersion modeling (*see* appendix W to 40 CFR part 51) to show that the mix of sources and enforceable control measures and emission rates in an identified area will not lead to a violation of the SO_2 NAAQS. For a short-term (*i.e.,* 1-hour) standard, EPA believes that dispersion modeling, using allowable emissions and addressing stationary sources in the affected area (and in some cases those sources located outside the nonattainment area which may affect attainment in the area) is technically appropriate, efficient, and effective in demonstrating attainment in nonattainment areas because it takes into consideration combinations of meteorological and emission source operating conditions that may contribute to peak ground-level concentrations of SO_2.

The meteorological data used in the analysis should generally be processed with the most recent version of AERMET. Estimated concentrations should include ambient background concentrations, should follow the form of the standard, and should be calculated as described in section 2.6.1.2 of the August 23, 2010, clarification memo on ''Applicability of Appendix W Modeling Guidance for the 1-hr SO_2 National Ambient Air Quality Standard'' (U.S. EPA, 2010).

IV. Review of Modeled Attainment Plan

This section generally discusses EPA's evaluation of the modeled attainment demonstration for Illinois' plan. A more detailed discussion is also presented in a technical support document (TSD) contained in the public docket for this proposed approval of Illinois' SIP.

A. Model Selection and General Model Inputs

As part of its SIP development process, Illinois used EPA's regulatory dispersion model, AERMOD, to help determine the SO_2 emission limit

was published on August 17, 2020, at 85 FR 49967, available at *https://www.govinfo.gov/content/pkg/FR-2020-08-17/pdf/2020-16044.pdf.* A more detailed description of these analyses is available in the docket for that action, specifically at *https://www.regulations.gov/document?D=EPA-R05-OAR-2015-0700-0023.*

[3] For example, if the critical emission value is 1,000 pounds of SO_2 per hour, and a suitable adjustment factor is determined to be 70 percent, the recommended longer term average limit would be 700 pounds per hour.

revisions that would be needed to bring the Alton Township nonattainment area into attainment of the 2010 SO_2 NAAQS. For its 2018 Alton Township attainment plan, Illinois has relied upon AERMOD Version 18081 and the companion AERMOD User Guide documentation in developing this attainment demonstration. Regulatory default options were specified in developing the attainment demonstration that are consistent with established practices for use of AERMOD in determining NAAQS compliance for SIP revisions. Included among those default options are stack tip downwash, buoyancy induced dispersion, default wind profile coefficients, default vertical potential temperature gradients, and final plume rise. EPA finds these selections appropriate.

This attainment demonstration uses a modeling domain that reflects the geographic extent of emission sources included in the Round 2 modeling for the Wood River Power Plant. The most significant sources addressed in the modeling for the area are the Alton Steel facility and the Ameren-Sioux power center in Missouri about 13 kilometers west-northwest of the nonattainment area. These two facilities are the principal causes of the modeled violations in the area. Illinois modeled several other, relatively minor sources within the area that did not contribute significantly to the violation. Illinois performed a culpability analysis to quantify the impacts of these various minor sources to determine their contribution to the modeled violations. At the highest concentrations the model estimated in the area, all other sources combined, aside from Ameren-Sioux and Alton Steel, contributed less than 2 $\mu g/m^3$ in total to the modeled violations. The way these sources are modeled are discussed in detail below.

The receptor network encompasses the nonattainment area and consists of discrete fence line receptors spaced at approximately 50-meter intervals and a gridded receptor array with 100-meter interval spacings. The receptor density is consistent with standard modeling guidance for adequately capturing and resolving SO_2 concentration maxima. See TSD pg. 3.

Selection of terrain data corresponds to the geographic area represented by the Alton Township nonattainment area, as well as the locations of facilities nearby that influence concentrations in the area. U.S. Geological Survey (USGS) National Elevation Dataset (NED) data were obtained in an appropriate format for use in AERMAP and used for generating the necessary terrain inputs. Elevations from the NED data were determined for all sources and structures, and both elevations and representative hill heights were determined for receptors.

A detailed site characterization of the Alton Steel facility, Ameren-Sioux power center, and pertinent other sources provided dimensional and locational data for structures and stacks necessary for addressing building-induced plume downwash. Stacks constructed to less than good engineering practice (GEP) height and within the ''zone of influence'' of a nearby structure have plumes that are potentially subject to excessive downwash. Illinois used EPA's Building Profile Input Program with PRIME algorithm (BPIPPRM, version 04274) to generate direction-specific building parameters for modeling building wake effects. The location and height of each stack and flare to be evaluated, and the locations and heights of nearby structures, were processed in BPIPPRM to produce the building parameters required by AERMOD.

Most of the stacks modeled by Illinois are modeled at heights that BPIPPRM considers to be at or below GEP height. However, two sources in this analysis were modeled by Illinois with stacks above GEP height. The stack at the Ameren-Sioux facility is constructed above GEP height and was modeled by Illinois at actual height. Additionally, at WRB Refining, several stacks have been constructed with heights above GEP height and were modeled at the actual stack height and at full potential to emit. WRB Refining, despite being modeled above GEP height, is not considered a significant contributor to the violations in the area. Illinois performed a culpability analysis and concluded that WRB has a very low contribution, less than 1 $\mu g/m^3$ in all modeled scenarios, to the modeled violations. As such, Illinois modeling that facility at GEP height would change little about the principal sources of SO_2 pollution in the area. Ameren-Sioux was modeled at above GEP height and was determined to be a significant contributor to the violations in the area. EPA has conducted supplemental modeling to correct any deficiencies in Illinois's modeling related to the characterization of emissions in the area. EPA used Illinois' receptor grid, meteorological surface and upper air stations, model settings, and some source parameters to develop the modeling demonstration. EPA is relying on our supplemental modeling to support the attainment plan and establish that the area is now modeling attainment. See TSD pg. 6.

More discussion on this topic is included in the sections below.

B. Meteorological Data

Procedures for selecting and developing meteorological data have been provided in the draft document ''Regional Meteorological Data Processing Protocol, EPA Region 5 and States.'' [4] This document describes selection criteria for surface meteorological data that address the representativeness of the meteorological data collection site to the emission source/receptor impact area. There are two specific criteria to be considered: (1) the suitability of meteorological data for the study area, and (2) the similarity of surface conditions and surroundings at the emission source/receptor impact area compared to characteristics at the location of the meteorological instrumentation tower.

In its 2018 submission, Illinois used the then-most recent five years (2012–2016) of surface meteorological data from St. Louis, Missouri (WBAN No. 13994, 28 kilometers to the southwest) and coincident upper air data from Lincoln, Illinois (WBAN No. 4833, 157 km to the northeast). These data were determined to be representative of the NAA's airshed. These data, in combination with surface characteristics data, were processed using AERSURFACE (version 13016) to prepare the meteorological data for simulating the area's planetary boundary layer turbulence structure. Illinois utilized AERMET (version 16216) to process the raw meteorological data. Illinois obtained Automated Surface Observing Systems (ASOS) one-minute wind speed and wind direction data for NWS surface stations and processed it using AERMINUTE (version 15272). EPA utilized the meteorological data processed by Illinois in its supplemental modeling. See TSD pg. 13.

The frequency and magnitude of wind speed and direction are defined in terms of where the wind is blowing from, parsed out in sixteen 22.5-degree wind sectors. The predominant wind direction during the five-year period is from the south, occurring approximately 9.8% of the time. The highest percentage wind speed range, occurring 34.5% of the time, was in the 3.6–5.7 meters per second range.

C. Modeled Emissions Data

In its 2018 submittal, Illinois provided an analysis modeling other

[4] Draft—*Regional Meteorological Data Processing Protocol. EPA Region 5 and States* (August 2014), available in the docket for this action.

SO_2 sources in the area, including GBC Metals, Olin Corporation, National Maintenance & Repair, Alton Water Treatment Facility, Conoco-Phillips Hartford Plant, Alton Memorial Hospital, St. Anthony's Hospital, St. Claire's Hospital, the Charles E. Mahoney Plant, WRB Refinery, and most notably including the Alton Steel facility and the Ameren-Sioux facility. Data for detailed site characterization (stack locations, fence line locations, building dimensions, etc.) of these sources were gathered and/or generated to support development of specific AERMOD inputs. Illinois used EPA's Building Profile Input Program with PRIME algorithm (BPIPPRM, version 04274) to generate direction-specific building inputs for modeling building wake effects within AERMOD. Building-induced plume downwash was addressed for all stacks and flares. The flares, all of which are located at WRB Refining, were modeled with adjusted release parameters including fixed values for temperature, exit velocity, and modified values for release height and diameter. Illinois relied upon the AERSCREEN User's Guide [5] to calculate the effective height and diameter for modeling the flares. Following the submittal from Illinois, EPA performed a supplemental modeling run to evaluate changes in allowable emissions that occurred after Illinois submitted the attainment plan and to correct any deficiencies in the emissions data or source characterization that could potentially cause reduced concentrations. See TSD p. 2.

The most significant sources affecting the nonattainment area were Alton Steel and the Ameren-Sioux facility in Missouri. While the Ameren-Sioux facility is not in the nonattainment area, Illinois modeled this facility due to its proximity to the nonattainment area and its high SO_2 emissions, yielding an impact of up to 283.4 $\mu g/m^3$ on the air quality in the area. Illinois modeled numerous minor point sources in the nonattainment area as well. Illinois did not explicitly model emissions from non-point sources, for example mobile emissions, incineration, agricultural field burning, etc., in AERMOD but instead represented the impact of these sources via monitored background data.

Illinois' SIP submittal describes an exploratory run that Illinois conducted in order to define the air quality problem in the area and to determine the most appropriate remedy. Notably, the baghouse at Alton Steel was originally configured to emit out of downward pointing vents, which Illinois modeled using the POINTHOR option in AERMOD to consider the horizontally pointing vents. Based on the results of these runs in which Alton Steel was the principal contributor to the highest modeled violations, Illinois chose to mandate construction of a single vertical unobstructed stack for this emission unit. Thus, Illinois' attainment demonstration modeling represented this emission point (and all other emission points) as a vertical unobstructed stack release. Flares were modeled with adjusted release parameters, consistent with EPA's guidance for modeling flares presented in the AERSCREEN User's Guide.[6] The adjusted parameters include fixed values for temperature (1,273 degrees Kelvin) and exit velocity (20 meters/second) and modified values for release height and diameter.

Ameren-Sioux operates two coal-fired boilers. Illinois modeled this source using information provided by the Missouri Department of Natural Resources. Illinois' modeling indicated that the limit on Ameren-Sioux in Missouri's SIP of 4.8 lbs/MMBtu did not ensure attainment inside the Alton nonattainment area. Illinois' modeling run evaluating the impact of maximum allowable emissions from Ameren-Sioux also reflecting the reconfigured ladle metallurgy facility (LMF) stack for Alton Steel yielded a maximum predicted 99th percentile 1-hour average concentration of 298.5 $\mu g/m^3$, and Illinois concluded that scaling this result down to reflect a temporally representative operating rate (either a 60th or a 70th percentile rate) for Ameren-Sioux would also show violations.

EPA conducted a supplemental modeling run to correct deficiencies in the characterization of emissions in Illinois's modeling. EPA evaluated the estimated concentrations based on application of a new limit of 7,342 lbs/hour averaged over a 24-hour block period on the Ameren-Sioux facility published on November 16, 2022 (87 FR 68634). The adopted new limit is substantially lower than the previous SIP limit of 4.8 lbs/MMBtu. Each of the facility's two boilers are rated to have a maximum heat input capacity of 4,920 MMBtu/hr and when applied to the former rate limit, add up to an effective rate of 47,232 lbs/hour on a facility-wide basis. The newly adopted limit marks a significantly reduced emission rate for the facility. EPA's supplemental modeling was based on the modeling runs submitted by Illinois, which modeled maximum uncontrolled emissions limits for all sources at the time but did not consider the revised limit at Ameren-Sioux. EPA's supplemental model run revised the modeled emissions for Ameren-Sioux to reflect the new 24-hour block limit and modeled the facility at GEP height.

The revised limit on Ameren-Sioux is on a 24-hour block average basis. Much of EPA's 2014 guidance addresses the situation in which modeling is used to determine the 1-hour critical emissions value used to calculate a limit necessary to provide for attainment, in which an adjustment factor is determined and applied to identify a reduced longer-term average limit to correspond to the modeled 1-hour value. The comparable stringency methodology provided in the guidance could also be utilized to estimate a 1-hour emission rate that may be used in a dispersion modeling run. Specifically, a preexisting longer-term average limit can be divided by the appropriate adjustment factor to determine an hourly modeled emission rate that is commensurate with the longer-term limit. Application of an adjustment factor means modeling this source using an hourly emission rate to which the 24-hour block limit established in Missouri's SIP is comparably stringent.

In EPA's supplemental modeling run, the emissions from Boilers 1 and 2 were treated as merged for a combined emissions rate from Ameren-Sioux. EPA's stack height regulations restrict the circumstances under which plume merging is creditable. Under 40 CFR 51.100(hh), plume merging is defined to be a prohibited dispersion technique except, in the case of merging occurring after July 8, 1985, for cases in which such merging is part of a change in operation at the facility that includes the installation of pollution controls and is accompanied by a net reduction in the allowable emissions of a pollutant. (See 40 CFR 51.100(hh)(2)(B)). The stack height regulations also note that this exclusion from the definition of dispersion techniques shall apply only to the emission limitation for the pollutant affected by such change in operation. To reduce its SO_2 emissions, Ameren-Sioux began operation of flue gas desulfurization of the emissions from Boilers 1 and 2 on November 15, 2010, and October 26, 2010, respectively. The construction of the new stack to vent the emissions from these units was part of the same project as installation of flue gas desulfurization equipment. Although Missouri did not adjust its SIP emission limit to reflect the reduction of allowable emissions

[5] *AERSCREEN User's Guide.* EPA–454/B–16–004. December 2016. U.S. Environmental Protection Agency, Research Triangle Park, NC.

[6] See supra n.5.

until several years after the installation of the pollution controls, the merging accompanied the installation of controls and may also be considered to accompany a net reduction in allowable emissions because the initial request for credit for merging was accompanied by a limit that required the net emission reduction that the Ameren-Sioux control project achieved. *See* TSD at 5.

The final SO_2 emission rate modeled for the merged Boilers 1 and 2 stack at Ameren-Sioux was 10,301.669 lbs/hr (1,297.988 g/s). Based on guidance from the 2014 U.S. EPA's SO_2 NAAQS Designations Modeling Technical Assistance Document, a ratio of 1-hour to 24-hour block average 99th percentile SO_2 emission rates in lbs/hr were calculated using data collected from 2016–2020. This resulted in an adjustment factor of 2,007 lbs/hr/2,816 lbs/hr = 0.7127. When the adjustment factor of 0.7127 is applied to the 24-hour block limit of 7,342 lbs/hr, a 1-hour emission rate to which the longer-term limit would be comparably stringent to would be 10,301.669 lbs/hr. The merged stack was modeled using the GEP stack height of 145.41 meters.

The other model inputs of EPA's supplemental run, *i.e.,* receptor grid, background concentrations, meteorological data, and list of modeled sources, were consistent with the Illinois submitted modeling. Stack heights for the merged two vents at Ameren-Sioux and two stacks at WRB Refining were modified in the supplemental run to be consistent with GEP stack heights. The supplemental run used version 21112 of AERMOD. Results of these runs are described below.

D. Emission Limits

A key element of Illinois' attainment plan is a change in Alton Steel's LMF exhaust configuration from the four downward-angled vents to a single 70-foot high, three-foot diameter stack with an unobstructed (no rain cap), vertically directed exhaust stream, which is represented in their final modeling. This change was mandated in Illinois' Construction Permit #18020009. As required by the construction permit, the SO_2 emissions of this furnace shall not exceed 0.10 pound/ton of steel produced, 11.20 pounds per hour and 37.50 tons per year. The first two of these limits apply on an hourly basis, such that Illinois' plan is designed to provide for attainment based on emission limits for the primary source in the area that apply every hour. Illinois is not relying on the limit on annual emissions to provide for attainment.

An important prerequisite for approval of an attainment plan is that the emission limits that provide for attainment be quantifiable, fully enforceable, replicable, and accountable. *See* General Preamble at 13567–68. The revised SO_2 emission SIP limit at Ameren-Sioux is expressed as a 24-hour block average limit. Therefore, part of the review of Illinois' attainment plan must address the use of these limits, both with respect to the general suitability of using this limit for this purpose and with respect to whether the particular limits included in and/or credited by the plan have been suitably demonstrated to provide for attainment. The first subsection that follows addresses the enforceability of the limits in and/or credited by the plan, and the second subsection that follows addresses the credited 24-hour block limit.

1. Enforceability

The change to Alton Steel's LMF exhaust configuration from the four downward-angled vents to a single 70-foot high, three-foot diameter stack with an unobstructed (no rain cap), vertically directed exhaust was mandated in Illinois Construction Permit #18020009, which is being incorporated into Illinois' SIP in the present action. This permitting action provides the federal enforceability supporting this portion of the attainment demonstration element of the revised SIP. As required by the construction permit, the SO_2 emissions of this furnace shall not exceed 0.10 pound per ton of steel produced, 11.20 pounds per hour and 37.50 tons per year. EPA considers these emission limits and source configuration requirements, specified in Construction Permit Number #18020009, to be suitably enforceable. The facility must submit annual compliance certifications to ensure that the facility is meetings its SIP limits. Additionally, the facility must submit a semi-annual Monitoring Report to the Illinois EPA, Air Compliance Section, summarizing required monitoring and identifying all instances of deviation from the permit. Stack testing must be done to verify the margin of compliance with the SO_2 limit.

For Ameren-Sioux, EPA has approved a more stringent 24-hour block limit submitted by Missouri that is aimed at reducing the facility's allowable emissions to levels that will allow the Alton nonattainment area to be modeled in attainment.[7] Ameren-Sioux will be subject to the more restrictive limit of 7,342 lbs/hour of SO_2 averaged over a 24-hour block period. Being a large coal fired EGU, the Ameren-Sioux facility is required to monitor its release of SO_2 via CEMS for other reasons such as the acid rain program and the Cross-State Air Pollution Rule (CSAPR). This requirement also provides for a means to measure compliance at the source to ensure that the facility does not exceed its permanent and enforceable limit. To demonstrate compliance, Ameren must calculate the calendar day 24-hour block average emission for each unit subject to the facility wide emission limit. Unit level emission rates will then be summed together to determine a facility wide emission rate. Only valid operating hours will be included in the calculations for the daily emission rates. Valid operating hours include only hours that meet the primary equipment hourly operating requirements of 40 CFR 75.10(d). For example, if the source only meets 40 CFR 75.10(d) operational requirements for one hour in a particular 24-hour block period, the compliance with the emissions limit would be calculated by the total emissions divided by the one hour of operation that meets 40 CFR 75.10(d). Therefore, any day with at least one hour that meets operational requirements will have a calculated block average that will be used to demonstrate compliance with the emissions limit. Hours when the units are experiencing startup, shutdown, or malfunction conditions will be used for the calculation if they meet the primary equipment hourly operating requirements of 40 CFR 75.10(d).

2. Longer-Term Average Limits

As noted above, while Illinois considered only the 1-hour average limits it adopted for Alton Steel, EPA also considered the updated 24-hour block limit approved into the Missouri SIP for the Ameren-Sioux facility. Therefore, the hypothetical critical emissions value to which Ameren-Sioux's 24-hour block average limit would be comparably stringent, and that is used in the attainment modeling for the area, would reflect an upward adjustment from the 7,342 lbs/hour averaged over a 24-hour block period. EPA conducted a site-specific analysis of variability at Ameren-Sioux using 2016–2020 CEMS data from EPA's Clean Air Markets Division's MySQL database, which was the most up to date information available at the time of analysis. EPA employed the method detailed in our 2014 guidance and used the historic 1-hour 99th percentile of SO_2 emissions against the 99th percentile 24-hour block average to derive an appropriate adjustment factor.

[7] See 87 FR 68634.

EPA determined that the adjustment factor for the Ameren-Sioux facility is 0.7127 and that it would be appropriate to apply this adjustment factor to Ameren-Sioux's long term averaging limit in order to estimate a 1-hour emission rate for modeling purposes. After applying the adjustment factor, EPA determined that a 1-hour emission rate used for modeling purposes would be 10,301.669 lbs/hour. EPA has determined through our supplemental modeling that an hourly emissions rate of 10,301.669 lbs/hour is protective of the standard. As such, EPA determines that Ameren-Sioux's updated limit of 7,342 lbs/hour will provide for attainment in the nonattainment area.

E. Background Concentrations

The Illinois demonstration of modeled attainment of the 2010 SO_2 NAAQS is based upon the combined impacts of facility-specific emission rates together with monitored background concentrations integrated into the simulations. Regional sources not explicitly modeled in AERMOD, but which are contributors to ambient SO_2 loadings within the nonattainment area, are represented via background monitoring data. In accordance with a ''Tier 2'' approach in EPA's guidance on background concentrations, Illinois identified separate background values for each hour of the day for each of the four seasons, for a total of 96 background values. Each of these values represents a three-year average (2014–2016) of the second highest hourly concentration for the applicable hour of the day for the applicable season. The seasonal, hourly-averaged 2014–2016 SO_2 background values for the attainment demonstration were developed from data collected at the East St. Louis monitor. *See* TSD at 13. These values range from 6.81 to 27.4 ppb, with an average value of 14.94 ppb.

F. Summary of Results

Illinois evaluated many factors in their modeling runs to evaluate measures needed to ensure attainment in the area. In their modeling runs, Illinois indicated that the prior limit in Ameren-Sioux's Missouri's SIP did not ensure attainment. Illinois determined that the impact of maximum allowable emissions from Ameren-Sioux also reflecting the reconfigured LMF stack for Alton Steel yielded a maximum predicted 99th percentile 1-hour average concentration of 298.5 μg/m³, and Illinois concluded that scaling this result down to reflect a temporally representative operating rate (either a 60th or a 70th percentile rate) would also show violations.

EPA concludes that Illinois' modeling is a suitable demonstration that its requirements in the new permit for Alton Steel and all other Illinois sources in the nonattainment area were properly addressed in the attainment plan. EPA's supplemental modeling has demonstrated that the updated 24-hour block limit for Ameren-Sioux of 7,342 lbs SO_2/hr and the revised limits at Alton Steel provide for attainment. For reasons described above, EPA considers the limits relied upon in this plan to be permanent and enforceable. EPA's modeling suitably demonstrates that the Ameren-Sioux limit (in combination with requirements for Alton Steel) provides for attainment.

As noted above, EPA conducted a supplementary modeling run to evaluate the Ameren-Sioux facility subject to the updated 7,342 lbs SO_2/hr 24-hour block limit that is found in the Missouri SIP. Since this limit is evaluated on a 24-hour block basis, EPA applied a 71.27 percent adjustment factor, modeling a 1-hour emissions rate of 10,300.666 lbs SO_2 per hour to which the 24-hour block limit is comparably stringent. The modeled design value from EPA's supplemental run was 196.2 μg/m³, or 74.9 ppb. This run used GEP stack heights, which for two facilities were slightly lower than the heights Illinois modeled; a separate supplementary run without these corrections yielded essentially identical results. These results confirm Illinois' demonstration that with the applicability and creditability of revised limits for Alton Steel and Ameren-Sioux, Illinois' plan provides for attainment. EPA believes that this 24-hour block average emission limit, in combination with the requirements for Alton Steel, are suitable elements of a plan that appropriately provides for attainment.

V. Review of Other Plan Requirements

A. Emissions Inventory

The Round 2 Wood River Study Area emission inventory was used as the starting point for creating the Alton Township NAA modeling inventory. A re-evaluation of sources was instituted, which reflected a shift in modeling focus from Dynegy's Wood River Power Station to the Alton Steel ''mini-mill.'' This re-evaluation was also driven by the need to address allowable emissions (for the SIP revision) rather than actual emissions (for an area designation recommendation).

The emissions inventory and source emission rate data for an area serve as the foundation for air quality modeling and other analyses that enable states to: (1) estimate the degree to which different sources within a nonattainment area contribute to violations within the affected area; and (2) assess the prospects for attaining the standard based on alternative control measures. As noted above, the state must develop and submit to EPA a comprehensive, accurate, and current inventory of actual emissions from all sources of SO_2 emissions in each nonattainment area, as well as any sources located outside the nonattainment area which may affect attainment in the area. *See* CAA section 172(c)(3).

Illinois provided a comprehensive, accurate, and current inventory of emissions of SO_2 in and within 10 kilometers of the Alton township area. Illinois additionally examined whether any large sources beyond 10 kilometers of the nonattainment area might also have significant air quality impacts in the area, resulting in the addition of Ameren-Sioux to the inventory. By this means, Illinois has developed a thorough list of the sources with any potential to cause impacts that warrant including in the area's attainment modeling.

Illinois included the sources of WRB Refining Inc. (formerly named ConocoPhillips), National Maintenance and Repair Inc., GBC Metals LLC (d/b/a Olin Brass), Olin Corporation, Alton Water Treatment Facility, ConocoPhillips Hartford Lubricant Plant, Alton Memorial Hospital, St. Anthony's Hospital, St. Clare's Hospital, and Charles E. Mahoney Company along with Alton Steel. The emission sources at Alton Steel, as well as those for many of the modeled nearby Illinois facilities, do not operate with variable loads but rather as ''on-off'' process operations, with the notable exception of Ameren-Sioux. The emissions inventory that Illinois submitted reflects actual emissions of these sources.

TABLE 1—ALTON TOWNSHIP NAA MODELING INVENTORY—ACTUAL ALTON AREA 2017 SO_2 POINT SOURCE EMISSIONS

Source description	Emission rate (tons per year)
Alton Steel	45.39
National Maintenance & Repair	3.93
GBC Metals	0.64
Olin Corporation	0.12
Alton Water Treatment Facility	2.40
Conoco Philips Hartford Lubricant Plant	0.00
Ameren-Sioux Power Center	2,722.267
Alton Memorial Hospital	0.15
St. Anthony's Hospital	1.67
St. Clare's Hospital	0.02
Charles E. Mahoney	4.70
WRB	1,494.59
Ardent Mills LLC	0.006
Bluff City Minerals ACQ LLC	0.04
Precor Refining Group Inc	0.001
Linde LLC	0.005
Apex Oil Co Inc	0.014
Shell Oil Products US	0.0012
Koch Fertilizer LLC	0.0042

TABLE 2—TOTAL SO_2 EMISSIONS

Category	Emissions (tons per year)
Non-EGU Point	1,559.34
EGU Point	2,722.267
Area	81.5196
On-Road Mobile	11.2065
Off-Road Mobile	41.8851
Total	4,415.9512

B. RACM/RACT and Emissions Limitations and Control Measures

Section 172(c)(1) of the CAA requires states to adopt and submit all RACM, including RACT, as needed to attain the standards as expeditiously as practicable. Section 172(c)(6) requires the SIP to contain enforceable emission limits and control measures necessary to provide for timely attainment of the standard. Illinois has required the principal contributor to the NAAQS violations, Alton Steel, to build a stack aimed at reducing the facility's contribution to the nonattainment area. Alton Steel built a stack to disperse emissions more appropriately from their facility; this change, along with establishment of suitable emission limits in their construction permit, along with the proposed limit on Ameren-Sioux to be found in the Missouri SIP, ensures that the area will attain the SO_2 air quality standard. Consequently, consistent with EPA policy that reasonable measures do not extend beyond a set of measures that provide for attainment, Illinois asserts, and EPA concurs, that the state's plan satisfies requirements for RACM/RACT.

C. New Source Review (NSR)

EPA approved Illinois' nonattainment new source review rules on December 17, 1992 (57 FR 59928); September 27, 1995 (60 FR 49780); and May 13, 2003 (68 FR 25504). These rules provide for appropriate new source review for SO_2 sources undergoing construction or major modification in the Alton Township area without need for modification of the approved rules. Although these rules predated promulgation of the 2010 SO_2 standards, these rules are written in a manner such that new sources within areas that become designated nonattainment for this new standard, such as the Alton Township area, become subject to these nonattainment new source review requirements. Therefore, this requirement has been met for this area.

D. RFP

Section 172 of the CAA requires Illinois' Alton Township Attainment Plan SIP to provide for reasonable further progress toward attainment. For SO_2 SIPs, which address a small number of affected sources, requiring expeditious compliance with attainment emission limits can address the RFP requirement. Alton Steel was required to complete its stack construction and meet its emission limits by December 31, 2018. For Ameren-Sioux, a new limit was approved into the Missouri SIP establishing a more stringent limit by establishing a limit of 7,342 lbs/hour averaged over a 24-hour block period. EPA approved Ameren-Sioux's new limit on November 16, 2022 (87 FR 68634) and is permanent and enforceable. EPA concludes that the timely requirements in the state's plan, including revised limits and construction of a 70-foot-tall stack for the Alton Steel facility and the SIP approved limit of Ameren-Sioux, represent implementation of control measures as expeditiously as practicable. This plan shows that Illinois can provide for attaining the standard. Accordingly, EPA proposes to find that Illinois' plan provides for RFP.

E. Contingency Measures

Section 172 of the CAA requires that nonattainment plans include additional measures which will take effect if an area fails to meet RFP or fails to attain the standard by the attainment date. As noted above, EPA guidance describes special features of SO_2 planning that influence the suitability of alternative means of addressing the requirement in section 172(c)(9) for contingency measures for SO_2. An appropriate means of satisfying this requirement is for the state to have a comprehensive enforcement program that identifies sources of violations of the SO_2 NAAQS and for the state to undertake aggressive follow-up for compliance and enforcement. Illinois' plan provides for satisfying the contingency measure requirement in this manner for sources in the state. EPA concurs and proposes to approve Illinois' plan for meeting the contingency measure requirement in this manner.

VI. EPA's Proposed Action

EPA is proposing to approve Illinois' submission as a SIP revision, which the state submitted to EPA on December 31, 2018, for attaining the 2010 SO_2 NAAQS for the Alton Township nonattainment area. As part of this action, EPA is proposing to incorporate Illinois' Permit to Construct Number #18020009, applicable to Alton Steel, by reference into the SIP. The permit requires that Alton Steel operates a new LMF stack to replace the four downward facing vents on the individual compartments on the LMF stack. The SO_2 emissions from the LMF stack must not exceed 0.10 pound per ton of steel produced, 11.20 pounds per hour, and 37.50 tons per year.

This SO_2 nonattainment plan includes Illinois' attainment demonstration for the Alton township SO_2 nonattainment area. Although Illinois did not explicitly model air quality based on Ameren-Sioux's updated limit, Illinois provided sufficient information and modeling to enable EPA to conduct additionally necessary supplemental modeling to demonstrate that the revised limit at the Alton Steel facility, that will drastically reduce any contributions from Illinois to the violations modeled in the NAA, and a lower limit imposed on Ameren-Sioux by Missouri would allow the area to meet the standard. Therefore, EPA concludes that the modeling in Illinois' plan, as supplemented by EPA, adequately demonstrates that the control requirements that apply to relevant sources in and near the area, including the revised 24-hour block SO_2 limit for Ameren-Sioux, provide for attainment in the area. As previously explained, EPA conducted a confirmatory model run explicitly applying the more stringent limit at Ameren-Sioux, and factoring a historically representative adjustment factor, showing more directly that the measures in Illinois' plan as supplemented by this limit provide for attainment. This nonattainment plan also addresses requirements for emission inventories, RACT/RACM, RFP, and contingency measures. Illinois has previously addressed requirements regarding nonattainment area NSR. EPA has determined that Illinois' SO_2 nonattainment plan meets the applicable requirements of CAA sections 172, 191, and 192. EPA is taking public comments for thirty days following the publication of this proposed action in the **Federal Register**. EPA will take these comments into consideration in our final action.

VII. Incorporation by Reference

In this rule, EPA is proposing to include in a final EPA rule regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, EPA is proposing to incorporate by reference the Illinois construction permit for Alton Steel, Inc., issued March 5, 2018, as described in section VI. of this preamble. EPA has made, and will continue to make, these documents generally available through *www.regulations.gov* and at the EPA Region 5 Office (please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information).

VIII. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

• Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);

• Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);

• Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);

• Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);

• Does not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);

• Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);

• Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);

• Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and

• Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Sulfur oxides.

Dated: December 21, 2022.

Debra Shore,

Regional Administrator, Region 5.

[FR Doc. 2022–28158 Filed 12–29–22; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

RIN 0648–BL08

Fisheries of the Exclusive Economic Zone Off Alaska; Amendment 122 to the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area; Pacific Cod Trawl Cooperative Program

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and

Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of availability of fishery management plan amendment; request for comments.

SUMMARY: The North Pacific Fishery Management Council (Council) submitted Amendment 122 to the Fishery Management Plan (FMP) for groundfish of the Bering Sea and Aleutian Islands Management Area (BSAI) to the Secretary of Commerce for review. If approved, Amendment 122 would implement the Pacific cod Trawl Cooperative (PCTC) Program, a limited access privilege program. Amendment 122 is intended to promote the goals and objectives of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act), Amendment 122, and the BSAI FMP.

DATES: Comments must be received no later than February 28, 2023.

ADDRESSES: You may submit comments, identified by NOAA–NMFS–2022–0072, by any of the following methods:

- *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *https://www.regulations.gov* and enter NOAA–NMFS–2022–0072 in the Search box. Click on the ''Comment'' icon, complete the required fields, and enter or attach your comments.
- *Mail:* Submit written comments to the Assistant Regional Administrator, Sustainable Fisheries Division, Alaska Region NMFS. Mail comments to P.O. Box 21668, Juneau, AK 99802–1668.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered by NMFS. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.,* name, address), confidential business information, or otherwise sensitive information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous).

Electronic copies of Amendment 122 to the BSAI FMP, the Environmental Assessment/Regulatory Impact Review prepared for this action (the Analysis), and the Finding of No Significant Impact prepared for this action may be obtained from *www.regulations.gov* and the NMFS Alaska Region website at *https://www.fisheries.noaa.gov/region/alaska.*

FOR FURTHER INFORMATION CONTACT: Stephanie Warpinski, (907) 586–7228.

SUPPLEMENTARY INFORMATION:

The Magnuson-Stevens Act requires that each regional fishery management council submit any FMP amendment it prepares to NMFS for review and approval, disapproval, or partial approval by the Secretary of Commerce. The Magnuson-Stevens Act also requires that NMFS, upon receiving an FMP amendment, immediately publish a notice in the **Federal Register** announcing that the amendment is available for public review and comment. This notice announces that proposed Amendment 122 to the BSAI FMP is available for public review and comment.

The Council prepared, and the Secretary approved, the BSAI FMP under the authority of the Magnuson-Stevens Act (16 U.S.C. 1801 *et seq.*). The BSAI FMP is implemented by regulations governing U.S. fisheries at 50 CFR parts 600 and 679. The Council is authorized to prepare and recommend an FMP amendment for the conservation and management of a fishery covered under the FMP.

Amendment 122 would create a limited access privilege program—the PCTC Program—in the BSAI Pacific cod trawl fishery, allocating harvest quota to participants based on their history in the fishery. Amendment 122 would allocate quota share (QS) to groundfish License Limitation Program (LLP) license holders based on the harvest of BSAI Pacific cod during the qualifying years of 2009 through 2019. Amendment 122 would also allocate QS to a processor permit holder based on processing history during those qualifying years. Under this program, QS holders would be required to join a PCTC Program cooperative annually. Cooperatives would be allocated an exclusive harvest privilege in the form of cooperative quota (CQ), equal to the aggregate QS of all cooperative members. The Council's intent in recommending Amendment 122 is to improve the prosecution of the fishery by promoting safety and stability in the harvesting and processing sectors, increasing the value of the fishery, minimizing bycatch to the extent practicable, providing for the sustained participation of fishery dependent communities, and ensuring the sustainability and viability of the Pacific cod resource in the BSAI.

Amendment 122 would add section 3.7.6 of the FMP to: (1) Authorize the PCTC Program harvesters and processors to form cooperatives to harvest their QS; (2) Allocate QS to harvesters based on legal landings of targeted BSAI Pacific cod by trawl catcher vessels (CVs) during the 2009 to 2019 qualifying years; (3) Allocate QS to Bering Sea processors based on deliveries of legal landings of targeted BSAI Pacific cod by trawl CVs during the 2009 to 2019 qualifying years; (4) Establish annual halibut and crab prohibited species catch (PSC) limits specific to the BSAI Pacific cod trawl CV sector during the annual harvest specifications process; (5) Require cooperatives to reserve 12 percent of A season CQ as a set-aside for delivery to an Aleutian Islands shoreplant if the community of Adak or Atka file a notice of intent to process Pacific cod that year; (6) Establish an aggregate Gulf of Alaska (GOA) groundfish sideboard and halibut PSC limit for all American Fisheries Act (AFA) CVs that are not currently exempt from GOA sideboards (except when participating in the Central GOA Rockfish Program); (7) Restrict PCTC Program harvesters that are exempt from GOA sideboards from leasing CQ derived from their QS; and (8) Establish limitations on transferability of QS, requirements for cooperative reporting to the Council, and ownership and use caps.

Amendment 122 would remove section 3.6.5 of the FMP because Amendment 113 and its implementing regulations were vacated by the U.S. District Court for the District of Columbia (Court) on March 21, 2019. BSAI Amendment 113 required harvesters to deliver a certain amount of Pacific cod to AI shoreside processors, as recommended by the Council and implemented by NMFS at the start of the 2017 fishing year (81 FR 84434, November 23, 2016). This proposed amendment would remove Amendment 113 and implement an alternative delivery set-aside under which PCTC Program cooperatives would reserve CQ for delivery to an Aleutian Island shoreplant under certain conditions.

NMFS is soliciting public comments on proposed Amendment 122 through the end of the comment period (see **DATES**). NMFS intends to publish in the **Federal Register** and seek public comment on a proposed rule that would implement Amendment 122 following NMFS's evaluation of the proposed rule under the Magnuson-Stevens Act.

Respondents do not need to submit the same comments on Amendment 122 and the proposed rule. All relevant written comments received by the end of the applicable comment period, whether specifically directed to the FMP amendment or the proposed rule, will be considered by NMFS in the approval/disapproval decision for

Amendment 122 and addressed in the response to comments in the final rule. Comments received after that date may not be considered in the approval/disapproval decision on Amendment 122. To be certain of consideration, comments must be received, not just postmarked or otherwise transmitted, by the last day of the comment period (see **DATES**).

Authority: 16 U.S.C. 1801 *et seq.*

Dated: December 27, 2022.

Ngagne Jafnar Gueye,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2022–28467 Filed 12–29–22; 8:45 am]

BILLING CODE 3510–22–P

Notices

Federal Register

Vol. 87, No. 250

Friday, December 30, 2022

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Forest Service

Tri County Resource Advisory Committee

AGENCY: Forest Service, USDA.

ACTION: Notice of meeting.

SUMMARY: The Tri County Resource Advisory Committee (RAC) will have a hybrid meeting, with the option to attend virtually or in-person. The committee is authorized under the Secure Rural Schools and Community Self-Determination Act (the Act) and operates in compliance with the Federal Advisory Committee Act. The purpose of the committee is to improve collaborative relationships and to provide advice and recommendations to the Forest Service concerning projects and funding consistent with Title II of the Act. RAC information and virtual meeting information can be found at the following website: *https://www.fs.usda.gov/main/bdnf/workingtogether/advisorycommittees.*

DATES: The meeting will be held on Friday, February 3rd, 2023 beginning at 8:30 a.m. Mountian Standard Time. All RAC meetings are subject to cancellation. For status of the meeting prior to attendance, please contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

Written and Oral Comments: Individuals wishing to make an oral statement should request in writing by Friday, January 27, 2023, to be scheduled on the agenda. Anyone who would like to bring related matters to the attention of the committee may file written statements with the committee staff before or after the meeting. Written comments, requests for time for oral comments or requests for instructions to participate virtually must be sent to Catherine McRae, RAC Coordinator, 420 Barrett Street, Dillon, MT 59725, by email to *catherine.mcrae@usda.gov,* or by phone at 406–925–3353.

ADDRESSES: The meeting is open to the public and will be held at 420 Barrett St., Dillon, MT 59725–3572, in the large conference room or may be attended virtually. Virtual meeting participation details can be found on the website listed under **SUMMARY** or by contacting the person listed under **FOR FURTHER INFORMATION CONTACT.**

Written comments may be submitted as described under **SUPPLEMENTARY INFORMATION**. All comments, including names and addresses when provided, are placed in the record and are available for public inspection and copying. The public may inspect comments received upon request.

FOR FURTHER INFORMATION CONTACT: Catherine McRae, RAC Coordinator, by phone at 406–925–3353 or by email at *catherine.mcrae@usda.gov.* Individuals who use telecommunication devices for the deaf or hard of hearing (TDD) may call the Federal Relay Service (FRS) at 800–877–8339, 24 hours a day, every day of the year, including holidays.

SUPPLEMENTARY INFORMATION: The purpose of the meeting is to:

1. Discuss and provide recommendations on fee change proposals for developed recreation sites on National Forest lands.

2. Discuss and recommend new Title II projects.

This meeting is open to the public. The agenda will include time for people to make oral statements of three minutes or less. Individuals wishing to make an oral statement should request in writing by Friday, January 27, 2023, to be scheduled on the agenda. Anyone who would like to bring related matters to the attention of the committee may file written statements with the committee staff before or after the meeting. Written comments, requests for time for oral comments or requests for instructions to participate virtually must be sent to Catherine McRae, RAC Coordinator, 420 Barrett Street, Dillon, MT 59725, by email to *catherine.mcrae@usda.gov,* or by phone at 406–925–3353.

Meeting Accommodations: If you are a person requiring reasonable accommodation, please make requests in advance for sign language interpreting, assistive listening devices, or other reasonable accommodation. For access to the facility or proceedings, please contact the person listed in the section titled **FOR FURTHER INFORMATION CONTACT**. All reasonable accommodation requests are managed on a case by case basis.

USDA programs are prohibited from discriminating based on race, color, national origin, religion, sex, gender identity (including gender expression), sexual orientation, disability, age, marital status, family/parental status, income derived from a public assistance program, political beliefs, or reprisal or retaliation for prior civil rights activity, in any program or activity conducted or funded by USDA (not all bases apply to all programs). Remedies and complaint filing deadlines vary by program or incident.

Equal opportunity practices in accordance with USDA's policies will be followed in all appointments to the Committee. To ensure that the recommendations of the Committee have taken in account the needs of the diverse groups served by USDA, membership shall include to the extent possible, individuals with demonstrated ability to represent minorities, women, and person with disabilities. USDA is an equal opportunity provider, employer, and lender.

Dated: December 23, 2022.

Cikena Reid,

USDA Committee Management Officer.

[FR Doc. 2022–28411 Filed 12–29–22; 8:45 am]

BILLING CODE 3411–15–P

DEPARTMENT OF AGRICULTURE

Forest Service

Directive Publication Notice

AGENCY: Forest Service, Agriculture (USDA).

ACTION: Notice.

SUMMARY: The Forest Service, U.S. Department of Agriculture, provides direction to employees through issuances in its Directive System, comprised of the Forest Service Manual and Forest Service Handbooks. The Agency must provide public notice of and opportunity to comment on any directives that formulate standards, criteria, or guidelines applicable to Forest Service programs. Once per quarter, the Agency provides advance notice of proposed and interim directives that will be made available for public comment during the next

three months and notice of final directives issued in the last three months.

DATES: This notice identifies proposed and interim directives that will be published for public comment between January 1, 2023, and March 31, 2023; proposed and interim directives that were previously published for public comment but not yet finalized and issued; and final directives that have been issued since October 1, 2022.

ADDRESSES: Questions or comments may be submitted by email to the contact listed below.

FOR FURTHER INFORMATION CONTACT: Jolynn Anderson, 971–313–1718 or *jolynn.anderson@usda.gov.* Individuals who use telecommunications devices for the hard of hearing may call the Federal Relay Service at 800–877–8339, 24 hours a day, every day of the year, including holidays. You may register to receive email alerts regarding Forest Service directives at *https://www.fs.usda.gov/about-agency/regulations-policies.*

SUPPLEMENTARY INFORMATION:

Proposed and Interim Directives

Consistent with 16 U.S.C. 1612(a) and 36 CFR part 216, the Forest Service publishes for public comment Agency directives that formulate standards, criteria, and guidelines applicable to Forest Service programs. Agency procedures for providing public notice and opportunity to comment are specified in Forest Service Handbook (FSH) 1109.12, Chapter 30, Providing Public Notice and Opportunity to Comment on Directives.

The following proposed directives are planned for publication for public comment from January 1, 2023, to March 31, 2023:

1. Forest Service Handbook (FSH) 2709.14, Recreation Special Uses Handbook, Chapter 40—Federally Owned Improvements and Chapter 80—Recreation and Other Temporary Events.
2. Forest Service Manual (FSM) 2340—Privately Provided Recreation Opportunities.

Previously Published Directives That Have Not Been Finalized

The following proposed and interim directives have been published for public comment but have not yet been finalized:

1. FSM 2200, Rangeland Management, Chapters Zero Code; 2210, Rangeland Management Planning; 2220, Management of Rangelands (Reserved); 2230, Grazing Permit System; 2240, Rangeland Improvements; 2250, Rangeland Management Cooperation; and 2270, Information Management and Reports; FSH 2209.13, Grazing Permit Administration Handbook, Chapters 10, Term Grazing Permits; 20, Grazing Agreements; 30, Temporary Grazing and Livestock Use Permits; 40, Livestock Use Permits; 50, Tribal Treaty Authorizations and Special Use Permits; 60, Records; 70, Compensation for Permittee Interests in Rangeland Improvements; 80, Grazing Fees; and 90, Rangeland Management Decision Making; and FSH 2209.16, Allotment Management Handbook, Chapter 10, Allotment Management and Administration.
2. FSM 3800, Landscape Scale Restoration Program.
3. FSH 2409.12, Timber Cruising Handbook, Chapters 30, Cruising Systems; 40, Cruise Planning, Data Recording, and Cruise Reporting; 60, Quality Control; and 70, Designating Timber for Cutting.
4. FSH 2409.15, Timber Sale Administration Handbook, Chapters 20, Measuring and Accounting for Included Timber; 40, Rates and Payments; and 60, Operations and Other Provisions.

Final Directives That Have Been Issued Since October 1, 2022

No proposed or interim directives that were previously published for public comment have been issued since October 1, 2022.

Stephen E. Morse,

Acting Branch Chief, Directives and Regulations, National Forest System.

[FR Doc. 2022–28431 Filed 12–29–22; 8:45 am]

BILLING CODE 3411–15–P

DEPARTMENT OF AGRICULTURE

Forest Service

Southwest Montana Resource Advisory Committee

AGENCY: Forest Service, Agriculture (USDA).

ACTION: Notice of meeting.

SUMMARY: The Southwest Montana Resource Advisory Committee (RAC) will have a hybrid meeting, with the option to attend virtually or in-person. The committee is authorized under the Secure Rural Schools and Community Self-Determination Act (the Act) and operates in compliance with the Federal Advisory Committee Act. The purpose of the committee is to improve collaborative relationships and to provide advice and recommendations to the Forest Service concerning projects and funding consistent with Title II of the Act. RAC information and virtual meeting information can be found at the following website: *https://www.fs.usda.gov/main/bdnf/workingtogether/advisorycommittees.*

DATES: The meeting will be held on Thursday, February 2nd, 2023 beginning at 8:30 a.m. Mountain Standard Time. All RAC meetings are subject to cancellation.

Oral and Written Comments: Individuals wishing to make an oral statement should request in writing by Friday, January 27, 2023, to be scheduled on the agenda. Anyone who would like to bring related matters to the attention of the committee may file written statements with the committee staff before or after the meeting. Written comments, requests for time for oral comments or requests for instructions to participate virtually must be sent to Catherine McRae, RAC Coordinator, 420 Barrett Street, Dillon, MT 59725, by email to *catherine.mcrae@usda.gov,* or by phone at 406–925–3353.

For status of the meeting prior to attendance, please contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

ADDRESSES: The meeting is open to the public and will be held at 420 Barrett St., Dillon, MT 59725–3572, in the large conference room or may be attended virtually. Virtual meeting participation details can be found on the website listed under **SUMMARY** or by contacting the person listed under **FOR FURTHER INFORMATION CONTACT**.

Written comments may be submitted as described under **SUPPLEMENTARY INFORMATION**. All comments, including names and addresses when provided, are placed in the record and are available for public inspection and copying. The public may inspect comments received upon request.

FOR FURTHER INFORMATION CONTACT: Catherine McRae, RAC Coordinator, by phone at 406–925–3353 or by email at *catherine.mcrae@usda.gov*. Individuals who use telecommunication devices for the deaf or hard of hearing (TDD) may call the Federal Relay Service (FRS) at 800–877–8339, 24 hours a day, every day of the year, including holidays.

SUPPLEMENTARY INFORMATION: The purpose of the meeting is to:

1. Discuss and recommend new Title II projects.

This meeting is open to the public. The agenda will include time for people to make oral statements of three minutes or less. Individuals wishing to make an oral statement should request in writing by Friday, January 27, 2023, to be scheduled on the agenda. Anyone who would like to bring related matters to the attention of the committee may file written statements with the committee staff before or after the meeting. Written comments, requests for time for oral comments or requests for instructions to participate virtually must be sent to Catherine McRae, RAC Coordinator, 420 Barrett Street, Dillon, MT 59725, by email to *catherine.mcrae@usda.gov,* or by phone at 406–925–3353.

Meeting Accommodations: If you are a person requiring reasonable accommodation, please make requests in advance for sign language interpreting, assistive listening devices, or other reasonable accommodation. For access to the facility or proceedings, please contact the person listed in the section titled **FOR FURTHER INFORMATION CONTACT**. All reasonable accommodation requests are managed on a case by case basis.

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Equal opportunity practices in accordance with USDA's policies will be followed in all appointments to the Committee. To ensure that the recommendations of the Committee have taken in account the needs of the diverse groups served by USDA, membership shall include to the extent possible, individuals with demonstrated ability to represent minorities, women, and person with disabilities. USDA is an equal opportunity provider, employer, and lender.

Dated: December 23, 2022.

Cikena Reid,

USDA Committee Management Officer.

[FR Doc. 2022–28412 Filed 12–29–22; 8:45 am]

BILLING CODE 3411–15–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–523–812, A–535–903, A–520–807]

Circular Welded Carbon-Quality Steel Pipe From Oman, Pakistan, and the United Arab Emirates: Continuation of Antidumping Duty Orders

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: As a result of the determinations by the U.S. Department of Commerce (Commerce) and the U.S. International Trade Commission (ITC) that revocation of the antidumping duty (AD) orders on circular welded carbon-quality steel pipe (CWP) from Oman, Pakistan, and the United Arab Emirates (UAE) would likely lead to a continuation or recurrence of dumping and material injury to an industry in the United States, Commerce is publishing a notice of continuation of the AD orders.

DATES: Applicable December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Zachariah Hall, AD/CVD Operations, Office VIII, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–6261.

SUPPLEMENTARY INFORMATION:

Background

On November 1, 2021, Commerce initiated a five-year sunset review of the AD orders on CWP from Oman, Pakistan, and the UAE, pursuant to section 751(c) of the Tariff Act of 1930, as amended (the Act).[1] As a result of its review, Commerce determined that revocation of the AD orders on CWP from Oman, Pakistan, and the UAE would likely lead to a continuation or recurrence of dumping and, therefore, notified the ITC of the magnitude of the margins likely to prevail should the orders be revoked.[2] On December 23, 2022, the ITC published its determination, pursuant to section 751(c) of the Act, that revocation of the AD orders on CWP from Oman, Pakistan, and the UAE would likely lead to a continuation or recurrence of material injury to an industry in the United States within a reasonably foreseeable time.[3]

Scope of the Orders

The merchandise covered by these orders are welded carbon-quality steel pipes and tube, of circular cross-section, with an outside diameter (O.D.) not more than nominal 16 inches (406.4 mm), regardless of wall thickness, surface finish (*e.g.,* black, galvanized, or painted), end finish (plain end, beveled end, grooved, threaded, or threaded and coupled), or industry specification (*e.g.,* American Society for Testing and Materials International (ASTM), proprietary, or other), generally known as standard pipe, fence pipe and tube, sprinkler pipe, and structural pipe (although subject product may also be referred to as mechanical tubing). Specifically, the term ''carbon quality'' includes products in which:

(a) iron predominates, by weight, over each of the other contained elements;

(b) the carbon content is 2 percent or less, by weight; and

(c) none of the elements listed below exceeds the quantity, by weight, as indicated:

(i) 1.80 percent of manganese;
(ii) 2.25 percent of silicon;
(iii) 1.00 percent of copper;
(iv) 0.50 percent of aluminum;
(v) 1.25 percent of chromium;
(vi) 0.30 percent of cobalt;
(vii) 0.40 percent of lead;
(viii) 1.25 percent of nickel;
(ix) 0.30 percent of tungsten;
(x) 0.15 percent of molybdenum;
(xi) 0.10 percent of niobium;
(xii) 0.41 percent of titanium;
(xiii) 0.15 percent of vanadium; or
(xiv) 0.15 percent of zirconium.

Covered products are generally made to standard O.D. and wall thickness combinations. Pipe multi-stenciled to a standard and/or structural specification and to other specifications, such as American Petroleum Institute (API) API–5L specification, may also be covered by the scope of these investigations. In particular, such multi-stenciled merchandise is covered when it meets the physical description set forth above, and also has one or more of the following characteristics: is 32 feet in length or less; is less than 2.0 inches (50 mm) in outside diameter; has a galvanized and/or painted (*e.g.,* polyester coated) surface finish; or has a threaded and/or coupled end finish.

[1] *See Initiation of Five-Year (Sunset) Reviews,* 86 FR 60201 (November 1, 2021).

[2] *See Circular Welded Carbon-Quality Steel Pipe From Oman, Pakistan, and the United Arab Emirates: Final Results of Expedited Sunset Reviews of Antidumping Duty Orders,* 87 FR 9315 (February 18, 2022).

[3] *See Circular Welded Carbon-Quality Steel Pipe from Oman, Pakistan, and the United Arab Emirates; Determinations,* 87 FR 78995 (December 23, 2022); *see also Circular Welded Carbon-Quality Steel Pipe from Oman, Pakistan, and the United Arab Emirates,* Inv. No. 731–TA–1299–1300 and 1302 (Review), USITC Publication 5390 (December 2022).

Standard pipe is ordinarily made to ASTM specifications A53, A135, and A795, but can also be made to other specifications. Structural pipe is made primarily to ASTM specifications A252 and A500. Standard and structural pipe may also be produced to proprietary specifications rather than to industry specifications.

Sprinkler pipe is designed for sprinkler fire suppression systems and may be made to industry specifications such as ASTM A53 or to proprietary specifications.

Fence tubing is included in the scope regardless of certification to a specification listed in the exclusions below, and can also be made to the ASTM A513 specification. Products that meet the physical description set forth above but are made to the following nominal outside diameter and wall thickness combinations, which are recognized by the industry as typical for fence tubing, are included despite being certified to ASTM mechanical tubing specifications:

O.D. in inches (nominal)	Wall thickness in inches (nominal)	Gage
1.315	0.035	20
1.315	0.047	18
1.315	0.055	17
1.315	0.065	16
1.315	0.072	15
1.315	0.083	14
1.315	0.095	13
1.660	0.055	17
1.660	0.065	16
1.660	0.083	14
1.660	0.095	13
1.660	0.109	12
1.900	0.047	18
1.900	0.055	17
1.900	0.065	16
1.900	0.072	15
1.900	0.095	13
1.900	0.109	12
2.375	0.047	18
2.375	0.055	17
2.375	0.065	16
2.375	0.072	15
2.375	0.095	13
2.375	0.109	12
2.375	0.120	11
2.875	0.109	12
2.875	0.165	8
3.500	0.109	12
3.500	0.165	8
4.000	0.148	9
4.000	0.165	8
4.500	0.203	7

The scope of these orders does not include:

(a) pipe suitable for use in boilers, superheaters, heat exchangers, refining furnaces and feedwater heaters, whether or not cold drawn, which are defined by standards such as ASTM A178 or ASTM A192;

(b) finished electrical conduit, *i.e.,* Electrical Rigid Steel Conduit (also known as Electrical Rigid Metal Conduit and Electrical Rigid Metal Steel Conduit), Finished Electrical Metallic Tubing, and Electrical Intermediate Metal Conduit, which are defined by specifications such as American National Standard (ANSI) C80.1–2005, ANSI C80.3–2005, or ANSI C80.6–2005, and Underwriters Laboratories Inc. (UL) UL–6, UL–797, or UL–1242;

(c) finished scaffolding, *i.e.,* component parts of final, finished scaffolding that enter the United States unassembled as a ''kit.'' A kit is understood to mean a packaged combination of component parts that contains, at the time of importation, all of the necessary component parts to fully assemble final, finished scaffolding;

(d) tube and pipe hollows for redrawing;

(e) oil country tubular goods produced to API specifications;

(f) line pipe produced to only API specifications, such as API 5L, and not multi-stenciled; and

(g) mechanical tubing, whether or not cold-drawn, other than what is included in the above paragraphs.

The products subject to these orders are currently classifiable in Harmonized Tariff Schedule of the United States (HTSUS) statistical reporting numbers 7306.19.1010, 7306.19.1050, 7306.19.5110, 7306.19.5150, 7306.30.1000, 7306.30.5015, 7306.30.5020, 7306.30.5025, 7306.30.5032, 7306.30.5040, 7306.30.5055, 7306.30.5085, 7306.30.5090, 7306.50.1000, 7306.50.5030, 7306.50.5050, and 7306.50.5070. The HTSUS subheadings above are provided for convenience and U.S. Customs purposes only. The written description of the scope of the orders is dispositive.

Continuation of the Orders

As a result of the determinations by Commerce and the ITC that revocation of the AD orders would likely lead to a continuation or recurrence of dumping and material injury to an industry in the United States, pursuant to section 751(d)(2) of the Act, Commerce hereby orders the continuation of the AD orders on CWP from Oman, Pakistan, and the UAE. U.S. Customs and Border Protection will continue to collect AD cash deposits at the rates in effect at the time of entry for all imports of subject merchandise. The effective date of the continuation of the orders will be the date of publication in the **Federal Register** of this notice of continuation. Pursuant to section 751(c)(2) of the Act, Commerce intends to initiate the next five-year review of the orders not later than 30 days prior to the fifth anniversary of the effective date of continuation.

Notification to Interested Parties

This five-year sunset review and this notice are in accordance with section 751(c) of the Act and published pursuant to section 777(i)(1) of the Act.

Dated: December 23, 2022.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2022–28406 Filed 12–29–22; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC644]

North Pacific Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of hybrid meeting.

SUMMARY: The North Pacific Fishery Management Council (Council) Crab Plan Team will meet January 17, 2023, to January 20, 2023.

DATES: The meeting will be held on Tuesday, January 17, 2023, through Friday, January 20, 2023, from 8:30 a.m. to 4:30 p.m. AK time.

ADDRESSES: The meeting will be a hybrid meeting. Attend in-person at the North Pacific Fishery Management Council office, 1007 West Third Ave., Suite 400, Anchorage, AK 99501, or join the meeting online through the link at *https://meetings.npfmc.org/Meeting/Details/2968.*

Council address: North Pacific Fishery Management Council, 1007 West 3rd Ave., Anchorage, AK 99501–2252; telephone: (907) 271–2809. Instructions for attending the meeting via video conference are given under **SUPPLEMENTARY INFORMATION**, below.

FOR FURTHER INFORMATION CONTACT: Sarah Rheinsmith, Council staff; phone: (907) 271–2809; email: *sarah.rheinsmith@noaa.gov.* For technical support, please contact our admin Council staff, email: *npfmc.admin@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Agenda

Tuesday, January 17, 2023, Through Friday, January 20, 2023

The agenda will include: (a) a stock assessment modeling workshop; (b) Economic appendix of the Stock Assessment and Fishery Evaluation (SAFE) report; (c) Norton Sound Red King Crab (NSRKC)—final SAFE report chapter; (d) Snow crab Rebuilding plan update; (e) Crab Conservation actions Prioritization; (f) Aleutian Islands Golden King Crab (AIGKC) proposed model runs; (g) Pribilof Islands Red King Crab (PIGKC) proposed model runs; (h) guidelines for moving start date of models; (i) simpler modeling workshop proposal; (j) Bristol Bay Red King Crab (BBRKC) bycatch distribution models; (k) tagging updates; (l) Ocean Acidification; and (m) additional topics. The agenda is subject to change, and the latest version will be posted at *https://meetings.npfmc.org/Meeting/Details/2968* prior to the meeting, along with meeting materials.

Connection Information

You can attend the meeting online using a computer, tablet, or smart phone, or by phone only. Connection information will be posted online at: *https://meetings.npfmc.org/Meeting/Details/2968.*

Public Comment

Public comment letters will be accepted and should be submitted electronically to *https://meetings.npfmc.org/Meeting/Details/2968.*

Authority: 16 U.S.C. 1801 *et seq.*

Dated: December 27, 2022.

Rey Israel Marquez,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2022–28464 Filed 12–29–22; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC636]

Marine Mammals; File No. 27079

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; receipt of application.

SUMMARY: Notice is hereby given that Cantata Bio, 100 Enterprise Way, Suite A10, Scotts Valley, CA 95066 (Responsible Party: Jordan Zhang), has applied in due form for a permit to import a specimen from a humpback whale (*Megaptera novaeangliae*) for scientific research.

DATES: Written, telefaxed, or email comments must be received on or before January 30, 2023.

ADDRESSES: The application and related documents are available for review by selecting ''Records Open for Public Comment'' from the ''Features'' box on the Applications and Permits for Protected Species (APPS) home page, *https://apps.nmfs.noaa.gov,* and then selecting File No. 27079 from the list of available applications. These documents are also available upon written request via email to *NMFS.Pr1Comments@noaa.gov.*

Written comments on this application should be submitted via email to *NMFS.Pr1Comments@noaa.gov.* Please include File No. 27079 in the subject line of the email comment.

Those individuals requesting a public hearing should submit a written request via email to *NMFS.Pr1Comments@noaa.gov.* The request should set forth the specific reasons why a hearing on this application would be appropriate.

FOR FURTHER INFORMATION CONTACT: Jennifer Skidmore or Erin Markin, Ph.D., (301) 427–8401.

SUPPLEMENTARY INFORMATION: The subject permit is requested under the authority of the Marine Mammal Protection Act of 1972, as amended (MMPA; 16 U.S.C. 1361 *et seq.*) and the regulations governing the taking and importing of marine mammals (50 CFR part 216).

The applicant proposes to import a muscle sample from a single humpback whale that stranded in August of 2022 in the Cook Islands. This sample will be imported to Cantata Bio's laboratory in order to create a reference genome. The requested duration of the permit is 1 year.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), an initial determination has been made that the activity proposed is categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

Concurrent with the publication of this notice in the **Federal Register**, NMFS is forwarding copies of the application to the Marine Mammal Commission and its Committee of Scientific Advisors.

Dated: December 27, 2022.

Julia M. Harrison,

Chief, Permits and Conservation Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2022–28444 Filed 12–29–22; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC643]

North Pacific Fishery Management Council; Public Meeting

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of hybrid meeting.

SUMMARY: The North Pacific Fishery Management Council (NPFMC) Ecosystem Committee will meet January 18, 2023 through January 19, 2023.

DATES: The meeting will be held on Wednesday, January 18, 2023, from 9 a.m. to 5 p.m. and on Thursday, January 19, 2023, from 9 a.m. to 12 p.m., Alaska Time.

ADDRESSES: The meeting will be a hybrid meeting. Attend in-person at the North Pacific Research Board office, 1007 West Third Ave., Suite 100, Anchorage, AK 99501 or join online through the link at *https://meetings.npfmc.org/Meeting/Details/2971.*

Council address: North Pacific Fishery Management Council, 1007 W 3rd Ave., Anchorage, AK 99501–2252; telephone: (907) 271–2809. Instructions for attending the meeting are given under **SUPPLEMENTARY INFORMATION**, below.

FOR FURTHER INFORMATION CONTACT: Nicole Watson, Council staff; phone; (907) 271–2809 and email: *nicole.watson@noaa.gov.* For technical support, please contact administrative Council staff, email: *npfmc.admin@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Agenda

Wednesday, January 18, 2023 Through Thursday, January 19, 2023

The Ecosystem Committee agenda will include: (a) Gulf of Alaska Fishery Ecosystem Plan (GOA FEP) Considerations; (b) Groundfish Programmatic Supplemental Environmental Impact Statement (PSEIS) planning; (c) Essential Fish

Habitat (EFH) 5-year review summary report; (d) Local Knowledge Traditional Knowledge and Subsistence Task Force update; (e) Northern Fur Seal Co-management; and (f) other business. The agenda is subject to change, and the latest version will be posted at *https://meetings.npfmc.org/Meeting/Details/2971* prior to the meeting, along with meeting materials.

Connection Information

You can attend the meeting online using a computer, tablet, or smart phone; or by phone only. Connection information will be posted online at: *https://meetings.npfmc.org/Meeting/Details/2971.*

Public Comment

Public comment letters will be accepted and should be submitted electronically to *https://meetings.npfmc.org/Meeting/Details/2971.*

Authority: 16 U.S.C. 1801 *et seq.*

Dated: December 27, 2022.

Rey Israel Marquez,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2022–28463 Filed 12–29–22; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC630]

Marine Mammals; File No. 24378

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; receipt of application for permit amendment.

SUMMARY: Notice is hereby given that The University of Alaska Southeast, 1332 Seward Ave, Sitka, AK 99835 (Responsible Party: Jan Straley), has applied for an amendment to scientific research Permit No. 24378.

DATES: Written, telefaxed, or email comments must be received on or before January 30, 2023.

ADDRESSES: The application and related documents are available for review by selecting ''Records Open for Public Comment'' from the ''Features'' box on the Applications and Permits for Protected Species (APPS) home page, *https://apps.nmfs.noaa.gov,* and then selecting File No. 24378 from the list of available applications. These documents are also available upon written request via email to *NMFS.Pr1Comments@noaa.gov.*

Written comments on this application should be submitted via email to *NMFS.Pr1Comments@noaa.gov.* Please include File No. 24378 in the subject line of the email comment.

Those individuals requesting a public hearing should submit a written request via email to *NMFS.Pr1Comments@noaa.gov.* The request should set forth the specific reasons why a hearing on this application would be appropriate.

FOR FURTHER INFORMATION CONTACT: Courtney Smith, Ph.D., or Shasta McClenahan, Ph.D., (301) 427–8401.

SUPPLEMENTARY INFORMATION: The subject amendment to Permit No. 24378 is requested under the authority of the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1361 *et seq.*), the regulations governing the taking and importing of marine mammals (50 CFR part 216), the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*), and the regulations governing the taking, importing, and exporting of endangered and threatened species (50 CFR parts 222–226), and the Fur Seal Act of 1966, as amended (16 U.S.C. 1151 *et seq.*).

Permit No. 24378, issued on April 29, 2021, (86 FR 26013, May 12, 2021), authorizes the permit holder to conduct research on 18 species of cetaceans in Alaska, focusing on humpback (*Megaptera novaeangliae*), killer (*Orcinus orca*), and sperm (*Physeter macrocephalus*) whales. The objective of the research is to further the biological understanding of Alaskan cetaceans by evaluating species abundance, population and stock structure, life history parameters, foraging behavior and prey specialization, social behavior, seasonal movements and migrations, and depredation interactions with longline fishing vessels. Research methods include close approach by vessels and unmanned aircraft systems to conduct activities that may result in Level B harassment including photo-identification, behavioral observations, underwater photography/video, active acoustic sonar for prey mapping, biological sampling (prey samples, exhaled air, sloughed skin, feces), and collection of eDNA. The research also includes activities that may result in Level A harassment including biopsy sampling and tagging (suction-cup and dart/barb). Some marine mammal parts may be exported for analysis.

The permit holder is requesting the permit be amended to increase annual takes of gray whales (*Eschrichtius robustus*) from 100 to 250 for activities that may cause Level B harassment; and increase from 20 to 100 annual takes for biopsy sampling. The purpose of the requested amendment is to add a new study and objectives that will allow researchers to better understand the increasing gray whale presence, population dynamics, demographics, and foraging strategies in Sitka Sound. The permit will expire on April 30, 2026.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), an initial determination has been made that the activity proposed is categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

Concurrent with the publication of this notice in the **Federal Register**, NMFS is forwarding copies of this application to the Marine Mammal Commission and its Committee of Scientific Advisors.

Dated: December 27, 2022.

Julia M. Harrison,

Chief, Permits and Conservation Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2022–28443 Filed 12–29–22; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2022–SCC–0117]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Comment Request; Build America, Buy America Act (BABAA) Domestic Sourcing Requirements Waiver—United States Department of Education BABAA Waiver Request Form

AGENCY: Office of the Secretary (OS), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act (PRA) of 1995, the Department is proposing an extension without change of a currently approved information collection request (ICR).

DATES: Interested persons are invited to submit comments on or before January 30, 2023.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be submitted within 30 days of publication of this notice. Click on this link *www.reginfo.gov/public/do/PRAMain* to access the site. Find this information collection request (ICR) by selecting ''Department of Education'' under ''Currently Under Review,'' then check the ''Only Show ICR for Public Comment'' checkbox. *Reginfo.gov* provides two links to view documents related to this information collection request. Information collection forms and instructions may be found by clicking on the ''View Information Collection (IC) List'' link. Supporting statements and other supporting documentation may be found by clicking on the ''View Supporting Statement and Other Documents'' link.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Pedro Romero, (202) 453–7886.

SUPPLEMENTARY INFORMATION: The Department is especially interested in public comment addressing the following issues: (1) is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: Build America, Buy America Act (BABAA) Domestic Sourcing Requirements Waiver—United States Department of Education BABAA Waiver Request Form.

OMB Control Number: 1894–0018.

Type of Review: Extension without change of a currently approved ICR.

Respondents/Affected Public: State, local, and Tribal Governments.

Total Estimated Number of Annual Responses: 470.

Total Estimated Number of Annual Burden Hours: 4,700.

Abstract: In accordance with section 70914 of the Build America Buy America Act (Pub. L. 117–58 sections 70901–70953) (BABAA), grantees funded under Department of Education (the Department) programs that allow funds to be used for infrastructure projects (infrastructure programs), *i.e.,* construction and broadband infrastructure, may not use their grant funds for these infrastructure projects or activities unless they comply with the following BABAA sourcing requirements: (1) All iron and steel used in the infrastructure project or activity are produced in the United States, (2) All manufactured products used in the infrastructure project or activity are produced in the United States, and (3) All construction materials are manufactured in the United States.

The Department may, in accordance with sections 70914(b) and (d), 70921(b), 70935, and 70937 of BABAA, and the Office of Management and Budget Memorandum M 22–11, Initial Implementation Guidance on Application of Buy America Preference in Federal Financial Assistance Programs for Infrastructure, approve waivers to BABAA sourcing requirements submitted by grantees under programs it has identified as infrastructure programs when it determines that exceptions to these requirements apply. The Department may approve, subject to notice and comment requirements and the Office of Management and Budget Made in America Office (MIAO) review, the types of waivers listed below when one or more of the following conditions are met: (1) Public Interest Waiver—Applying the BABAA sourcing requirement would be inconsistent with the public interest, (2) Non-availability Waiver—The types of iron, steel, manufactured products, or construction materials are not produced in the United States in sufficient and reasonably available quantities or of a satisfactory quality, and (3) Unreasonable Cost Waiver—The inclusion of iron, steel, manufactured products, or construction materials produced in the United States will increase the cost of the overall project by more than 25 percent.

This is a new information collection and it includes the following two documents: (1) the Build America, Buy America Act (BABAA) Domestic Sourcing Requirements Waiver—United States Department of Education BABAA Waiver Request Form (BABAA Waiver Request Form); and (2) a document listing the BABAA Waiver Request Form data elements.

Dated: December 27, 2022.

Stephanie Valentine,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2022–28450 Filed 12–29–22; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. IC22–27–000]

Commission Information Collection Activities (FERC–915) Comment Request; Extension

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of information collection and request for comments.

SUMMARY: In compliance with the requirements of the Paperwork Reduction Act of 1995, the Federal Energy Regulatory Commission, FERC–915 (Public Utility Market-Based Rate Authorization Holders—Records Retention Requirements), will be submitted to the Office of Management and Budget (OMB) for review. No Comments were received on the 60-day notice published on October 6, 2022.

DATES: Comments on the collection of information are due January 30, 2023.

ADDRESSES: Send written comments on FERC–915 to OMB through *www.reginfo.gov/public/do/PRAMain.* Attention: Federal Energy Regulatory Commission Desk Officer. Please identify the OMB Control Number (1902–0250) in the subject line of your comments. Comments should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.*

Please submit copies of your comments to the Commission. You may submit copies of your comments (identified by Docket No. IC22–27–000) by one of the following methods:

Electronic filing through *https://www.ferc.gov,* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by USPS mail or by hand (including courier) delivery.
  - ○ *Mail via U.S. Postal Service Only:* Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.
  - ○ *Hand (including courier) delivery:* Deliver to: Federal Energy Regulatory Commission, Secretary of the Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

Instructions: OMB submissions must be formatted and filed in accordance with submission guidelines at *www.reginfo.gov/public/do/PRAMain.*

Using the search function under the "Currently Under Review" field, select Federal Energy Regulatory Commission; click "submit," and select "comment" to the right of the subject collection.

FERC submissions must be formatted and filed in accordance with submission guidelines at: *https://www.ferc.gov.* For user assistance, contact FERC Online Support by email at *ferconlinesupport@ferc.gov,* or by phone at: (866) 208–3676 (toll-free).

Docket: Users interested in receiving automatic notification of activity in this docket or in viewing/downloading comments and issuances in this docket may do so at *https://www.ferc.gov/ferc-online/overview.*

FOR FURTHER INFORMATION CONTACT: Ellen Brown may be reached by email at *DataClearance@FERC.gov,* telephone at (202) 502–8663.

SUPPLEMENTARY INFORMATION:

Title: FERC–915, Public Utility Market-Based Rate Authorization Holders—Records Retention Requirements.

OMB Control No.: 1902–0250.

Type of Request: Three-year extension of the FERC–915 information collection requirements with no changes to the current record retention requirements.

Abstract: In accordance with the Federal Power Act, the Department of Energy Organization Act (DOE Act), and the Energy Policy Act of 2005 (EPAct 2005), the Commission regulates the transmission and wholesale sales of electricity in interstate commerce, monitors and investigates energy markets, uses civil penalties and other means against energy organizations and individuals who violate FERC rules in the energy markets, administers accounting and financial reporting regulations, and oversees conduct of regulated companies.

The Commission imposes the FERC–915 record retention requirements in 18 CFR 35.41(d) on applicable sellers to retain, for a period of five years, all data and information upon which they bill the prices charged for "electric energy or electric energy products sold pursuant to Seller's market-based rate tariff, and the prices it reported for use in price indices."

FERC–915 is necessary to protect the integrity of the market by preserving documentation of relevant price data in the event of an investigation of possible wrongdoing. The requirement ensures that documentation is retained for a period consistent with the parameters of the generally applicable statute of limitations for the Commission to assess civil penalties against a seller for violations of the FERC's rules, regulations, or orders.

Type of Respondent: Sellers, as that term is defined in 18 CFR 35.36.

Estimate of Annual Burden: [1] The Commission estimates the annual public reporting burden and cost [2] (rounded) for the information collection as follows:

FERC–915, PUBLIC UTILITY MARKET-BASED RATE AUTHORIZATION HOLDERS—RECORDS RETENTION REQUIREMENTS

FERC requirement	Number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden & cost per response (4)	Total annual burden hours & cost (3) * (4) = (5)	Annual cost per respondent ($) (5) ÷ (1)
FERC–915	2,510	1	2,510	1 hr.; $34.00	2,510 hrs.; $85,340	$34.00
Total			2,510		2,510 hrs.; $85,340	

In addition, there are records storage costs. For all respondents, we estimate a total of 65,000 cu. ft. of records in off-site storage. Based on an approximate storage cost of $0.24 per cubic foot, we estimate total annual storage cost to be $15,600.00 (or $6.22 annually per respondent). The total annual cost for all respondents (burden cost plus off-site storage) is $100,940.00 (or $85,340 + $15,600); the average total annual cost per respondent is $40.22 ($6.22 + $34.00).[3]

Comments: Comments are invited on: (1) whether the collection of information is necessary for the proper performance of the functions of the Commission, including whether the information will have practical utility; (2) the accuracy of the agency's estimate of the burden and cost of the collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility and clarity of the information collection; and (4) ways to minimize the burden of the collection of information on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–28455 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP23–301–000.

Applicants: Alliance Pipeline L.P.

Description: § 4(d) Rate Filing: Negotiated Rates—Various Jan 1 2023 Releases to be effective 1/1/2023.

Filed Date: 12/21/22.

Accession Number: 20221221–5083.

Comment Date: 5 p.m. ET 1/2/23.

Docket Numbers: RP23–302–000.

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[1] Burden is defined as the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR 1320.3.

[2] The estimated hourly cost (for wages plus benefits) provided in this section are based on the figures posted by the Bureau of Labor Statistics (BLS) for the Utilities section available (at *https://www.bls.gov/oes/current/naics2_22.htm*) and benefits information (for June 2022, issued March 2022, at *https://www.bls.gov/news.release/ecec.nr0.htm*). The hourly estimates for salary plus benefits are:

File Clerk (Occupation code: 43–4071), $34.38 an hour. We are rounding the hourly cost to $34.00.

[3] Given that the Commission has found (1) that Sellers use standard computer-based methods to store the retained information automatically on electronic media and (2) that storage space needed costs pennies per Gigabyte, estimating burden and storage assuming use of traditional paper records provides an extreme boundary on the estimated costs.

Applicants: Enable Mississippi River Transmission, LLC.
Description: § 4(d) Rate Filing: Third Party Capacity Updates to be effective 1/21/2023.
Filed Date: 12/21/22.
Accession Number: 20221221–5117.
Comment Date: 5 p.m. ET 1/2/23.

Docket Numbers: RP23–303–000.
Applicants: Rockies Express Pipeline LLC.
Description: § 4(d) Rate Filing: REX 2022–12–21 Negotiated Rate Agreement Amendment to be effective 12/22/2022.
Filed Date: 12/21/22.
Accession Number: 20221221–5197.
Comment Date: 5 p.m. ET 1/2/23.

Docket Numbers: RP23–304–000.
Applicants: Equitrans, L.P.
Description: § 4(d) Rate Filing: Negotiated Rate Agreement—1/1/2023 to be effective 1/1/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5014.
Comment Date: 5 p.m. ET 1/3/23.

Docket Numbers: RP23–305–000.
Applicants: Great Basin Gas Transmission Company.
Description: Tariff Amendment: Cancel Tariff—Original Version No. 1 to be effective 1/23/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5064.
Comment Date: 5 p.m. ET 1/3/23.

Docket Numbers: RP23–306–000.
Applicants: Florida Gas Transmission Company, LLC.
Description: § 4(d) Rate Filing: Negotiated Rates Filing—FPL to be effective 12/24/2022.
Filed Date: 12/22/22.
Accession Number: 20221222–5077.
Comment Date: 5 p.m. ET 1/3/23.

Docket Numbers: RP23–307–000.
Applicants: Enable Gas Transmission, LLC.
Description: § 4(d) Rate Filing: NRA Filing to be effective 1/1/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5110.
Comment Date: 5 p.m. ET 1/3/23.

Docket Numbers: RP23–308–000.
Applicants: Mississippi Hub, LLC.
Description: § 4(d) Rate Filing: Mississippi Hub, LLC Tariff Filing to be effective 1/21/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5121.
Comment Date: 5 p.m. ET 1/3/23.

Docket Numbers: RP23–309–000.
Applicants: Natural Gas Pipeline Company of America LLC.
Description: § 4(d) Rate Filing: Negotiated Rate Agreement Filing—Golden Pass K150158 to be effective 1/1/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5131.
Comment Date: 5 p.m. ET 1/3/23.

Docket Numbers: RP23–310–000.
Applicants: Southern Star Central Gas Pipeline, Inc.
Description: § 4(d) Rate Filing: Gas Quality Filing 2022 to be effective 2/1/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5247.
Comment Date: 5 p.m. ET 1/3/23.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP22–1033–003.
Applicants: Northern Natural Gas Company.
Description: Compliance filing: 20221222 Interim Rates to be effective 1/1/2023.
Filed Date: 12/22/22.
Accession Number: 20221222–5145.
Comment Date: 5 p.m. ET 1/3/23.

Any person desiring to protest in any the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5:00 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–28452 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP23–26–000]

Texas Eastern Transmission, LP; Notice of Request Under Blanket Authorization and Establishing Intervention and Protest Deadline

Take notice that on December 13, 2022, Texas Eastern Transmission, LP (Texas Eastern), 915 N Eldridge Parkway, Suite 1100, Houston, Texas 77079, filed in the above referenced docket, a prior notice request pursuant to sections 157.205 and 157.216 of the Commission's regulations under the Natural Gas Act (NGA), and Texas Eastern's blanket certificate issued in Docket No. CP82–535–000, for authorization to abandon in place certain pipeline facilities, and abandon related meter and regulating (M&R) stations and ancillary facilities (Port 6 Laterals Pipeline Abandonment Project). The proposed abandonment and removal activities are located in DeWitt, Goliad, and Victoria Counties, Texas.

Texas Eastern also states that the Port 6 Laterals Pipeline Abandonment Project will have no impact on the certificated capacity of Texas Eastern's system, and that there will be no reduction in firm service to Texas Eastern's existing customers as a result of the proposed abandonment activities, all as more fully set forth in the application, which is on file with the Commission and open to public inspection.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*www.ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact FERC at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TTY, (202) 502–8659.

Any questions regarding this prior notice request should be directed to Estela D. Lozano, Director, Regulatory, Texas Eastern Transmission, LP, P.O. Box 1642, Houston, Texas 77251–1642, at (713) 627–4522, or by email to *estela.lozano@enbridge.com.*

Pursuant to Section 157.9 of the Commission's Rules of Practice and Procedure,[1] within 90 days of this Notice the Commission staff will either: complete its environmental review and place it into the Commission's public record (eLibrary) for this proceeding; or issue a Notice of Schedule for Environmental Review. If a Notice of Schedule for Environmental Review is issued, it will indicate, among other milestones, the anticipated date for the Commission staff's issuance of the final environmental impact statement (FEIS) or environmental assessment (EA) for this proposal. The filing of an EA in the Commission's public record for this proceeding or the issuance of a Notice of Schedule for Environmental Review will serve to notify federal and state agencies of the timing for the completion of all necessary reviews, and the subsequent need to complete all federal authorizations within 90 days of the date of issuance of the Commission staff's FEIS or EA.

Public Participation

There are three ways to become involved in the Commission's review of this project: you can file a protest to the project, you can file a motion to intervene in the proceeding, and you can file comments on the project. There is no fee or cost for filing protests, motions to intervene, or comments. The deadline for filing protests, motions to intervene, and comments is 5:00 p.m. Eastern Time on February 21, 2023. How to file protests, motions to intervene, and comments is explained below.

Protests

Pursuant to section 157.205 of the Commission's regulations under the NGA,[2] any person [3] or the Commission's staff may file a protest to the request. If no protest is filed within the time allowed or if a protest is filed and then withdrawn within 30 days after the allowed time for filing a protest, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request for authorization will be considered by the Commission.

Protests must comply with the requirements specified in section 157.205(e) of the Commission's regulations,[4] and must be submitted by the protest deadline, which is February 21, 2023. A protest may also serve as a motion to intervene so long as the protestor states it also seeks to be an intervenor.

Interventions

Any person has the option to file a motion to intervene in this proceeding. Only intervenors have the right to request rehearing of Commission orders issued in this proceeding and to subsequently challenge the Commission's orders in the U.S. Circuit Courts of Appeal.

To intervene, you must submit a motion to intervene to the Commission in accordance with Rule 214 of the Commission's Rules of Practice and Procedure [5] and the regulations under the NGA [6] by the intervention deadline for the project, which is February 21, 2023. As described further in Rule 214, your motion to intervene must state, to the extent known, your position regarding the proceeding, as well as your interest in the proceeding. For an individual, this could include your status as a landowner, ratepayer, resident of an impacted community, or recreationist. You do not need to have property directly impacted by the project in order to intervene. For more information about motions to intervene, refer to the FERC website at *https://www.ferc.gov/resources/guides/how-to/intervene.asp.*

All timely, unopposed motions to intervene are automatically granted by operation of Rule 214(c)(1). Motions to intervene that are filed after the intervention deadline are untimely and may be denied. Any late-filed motion to intervene must show good cause for being late and must explain why the time limitation should be waived and provide justification by reference to factors set forth in Rule 214(d) of the Commission's Rules and Regulations. A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies (paper or electronic) of all documents filed by the applicant and by all other parties.

Comments

Any person wishing to comment on the project may do so. The Commission considers all comments received about the project in determining the appropriate action to be taken. To ensure that your comments are timely and properly recorded, please submit your comments on or before February 21, 2023. The filing of a comment alone will not serve to make the filer a party to the proceeding. To become a party, you must intervene in the proceeding.

How To File Protests, Interventions, and Comments

There are two ways to submit protests, motions to intervene, and comments. In both instances, please reference the Project docket number CP23–26–000 in your submission.

(1) You may file your protest, motion to intervene, and comments by using the Commission's eFiling feature, which is located on the Commission's website (*www.ferc.gov*) under the link to Documents and Filings. New eFiling users must first create an account by clicking on ''eRegister.'' You will be asked to select the type of filing you are making; first select General'' and then select ''Protest'', ''Intervention'', or ''Comment on a Filing''; or [7]

(2) You can file a paper copy of your submission by mailing it to the address below. Your submission must reference the Project docket number CP23–26–000.

To mail via USPS, use the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

To mail via any other courier, use the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, Maryland 20852.

The Commission encourages electronic filing of submissions (option 1 above) and has eFiling staff available to assist you at (202) 502–8258 or *FercOnlineSupport@ferc.gov.*

Protests and motions to intervene must be served on the applicant either by mail at: Estela D. Lozano, Director, Regulatory, Texas Eastern Transmission, LP, P.O. Box 1642, Houston, Texas 77251–1642, or email (with a link to the document) at: *estela.lozano@enbridge.com.* Any subsequent submissions by an intervenor must be served on the applicant and all other parties to the proceeding. Contact information for parties can be downloaded from the service list at the eService link on FERC Online.

[1] 18 CFR (Code of Federal Regulations) 157.9.

[2] 18 CFR 157.205.

[3] Persons include individuals, organizations, businesses, municipalities, and other entities. 18 CFR 385.102(d).

[4] 18 CFR 157.205(e).

[5] 18 CFR 385.214.

[6] 18 CFR 157.10.

[7] Additionally, you may file your comments electronically by using the eComment feature, which is located on the Commission's website at *www.ferc.gov* under the link to Documents and Filings. Using eComment is an easy method for interested persons to submit brief, text-only comments on a project.

Tracking the Proceeding

Throughout the proceeding, additional information about the project will be available from the Commission's Office of External Affairs, at (866) 208–FERC, or on the FERC website at *www.ferc.gov* using the ''eLibrary'' link as described above. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. For more information and to register, go to *www.ferc.gov/docs-filing/esubscription.asp.*

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–28456 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC23–14–000.
Applicants: San Diego Gas & Electric Company, AES Energy Storage, LLC.
Description: Supplement to October 26, 2022 Joint Application for Authorization Under Section 203 of the Federal Power Act of San Diego Gas & Electric Company, et al. under.
Filed Date: 12/19/22.
Accession Number: 20221219–5237.
Comment Date: 5 p.m. ET 12/29/22.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER10–1246–017; ER10–1252–017; ER10–1253–015; ER10–1982–016.
Applicants: Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Consolidated Edison Solutions, Inc., Consolidated Edison Energy, Inc.
Description: Triennial Market Power Analysis for Northeast Region of Consolidated Edison Company of New York, Inc., et al.
Filed Date: 12/15/22.
Accession Number: 20221215–5238.
Comment Date: 5 p.m. ET 2/13/23.

Docket Numbers: ER10–1330–009; ER10–2032–010; ER10–2033–009; ER12–2313–007; ER15–190–021; ER15–255–005; ER16–141–006; ER16–355–004; ER17–2336–007; ER18–1343–015; ER18–2465–002; ER18–2466–002; ER19–2343–003.
Applicants: 2018 ESA Project Company, LLC, Federal Way Powerhouse LLC, Potter Road Powerhouse LLC, Carolina Solar Power, LLC, Shoreham Solar Commons LLC, Colonial Eagle Solar, LLC, Conetoe II Solar, LLC, Duke Energy Beckjord Storage, LLC, Duke Energy Renewable Services, LLC, Laurel Hill Wind Energy, LLC, Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., North Allegheny Wind, LLC.
Description: Triennial Market Power Analysis for Northeast Region of Duke MBR Sellers.
Filed Date: 12/20/22.
Accession Number: 20221220–5296.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–1790–021; ER12–1825–035; ER14–2672–022; ER21–1251–001; ER21–1716–003; ER22–2141–001.
Applicants: Sun Mountain Solar 1, LLC, BP Energy Holding Company LLC, Bighorn Solar 1, LLC, BP Energy Retail Company LLC, BP Energy Retail Company California, LLC, BP Energy Company.
Description: Triennial Market Power Analysis for Northwest Region of BP Energy Company, et al.
Filed Date: 12/21/22.
Accession Number: 20221221–5341.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2124–025.
Applicants: Spring Canyon Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Spring Canyon Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5336.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2125–026.
Applicants: Judith Gap Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Judith Gap Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5323.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2128–025.
Applicants: Wolverine Creek Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Wolverine Creek Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5322.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2129–015.
Applicants: Grays Harbor Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Grays Harbor Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5335.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2132–025.
Applicants: Willow Creek Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Willow Creek Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5319.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2135–015.
Applicants: Spindle Hill Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Spindle Hill Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5324.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2383–013; ER10–2384–011; ER14–2820–011; ER14–2821–011; ER16–853–006; ER16–855–006; ER16–856–006; ER16–857–006; ER16–858–006; ER16–860–006; ER16–861–006; ER19–1200–007; ER20–2014–002.
Applicants: Rattlesnake Flat, LLC, Clearway Power Marketing LLC, Iron Springs Solar, LLC, Granite Mountain Solar West, LLC, Granite Mountain Solar East, LLC, Escalante Solar III, LLC, Escalante Solar II, LLC, Escalante Solar I, LLC, Enterprise Solar, LLC, Spring Canyon Energy III LLC, Spring Canyon Energy II LLC, Mountain Wind Power, LLC, Mountain Wind Power II LLC.
Description: Triennial Market Power Analysis for Northwest Region of Clearway Power Marketing LLC, et al.
Filed Date: 12/20/22.
Accession Number: 20221220–5297.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2596–012; ER12–2200–007.
Applicants: Mehoopany Wind Energy LLC, Fowler Ridge II Wind Farm LLC.
Description: Triennial Market Power Analysis for Northeast Region of Fowler Ridge II Wind Farm LLC, et al.
Filed Date: 12/21/22.
Accession Number: 20221221–5325.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–2764–025.
Applicants: Vantage Wind Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Vantage Wind Energy LLC.
Filed Date: 12/21/22.
Accession Number: 20221221–5334.

Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER10–3297–018.
Applicants: Powerex Corporation.
Description: Notice of Change in Status of Powerex Corp.
Filed Date: 12/21/22.
Accession Number: 20221221–5328.
Comment Date: 5 p.m. ET 1/11/23.

Docket Numbers: ER11–2029–008.
Applicants: Cedar Creek II, LLC.
Description: Triennial Market Power Analysis for Northwest Region of Cedar Creek II, LLC.
Filed Date: 12/22/22.
Accession Number: 20221222–5314.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER11–2557–005; ER11–2552–005; ER11–2558–006; ER11–2555–004; ER11–2556–005.
Applicants: National Grid Port Jefferson, National Grid Glenwood Energy Center LLC, Niagara Mohawk Power Corporation, Massachusetts Electric Company, New England Power Company.
Description: Triennial Market Power Analysis for Northeast Region of New England Power Company, et al.
Filed Date: 12/22/22.
Accession Number: 20221222–5313.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER19–1217–003.
Applicants: Montana-Dakota Utilities Co.
Description: Triennial Market Power Analysis for Northwest Region of Montana-Dakota Utilities Co.
Filed Date: 12/22/22.
Accession Number: 20221222–5320.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER20–2444–005; ER20–2445–005.
Applicants: Prineville Solar Energy LLC, Millican Solar Energy LLC.
Description: Triennial Market Power Analysis for Northwest Region of Millican Solar Energy LLC, et al.
Filed Date: 12/21/22.
Accession Number: 20221221–5333.
Comment Date: 5 p.m. ET 2/20/23.

Docket Numbers: ER23–724–000.
Applicants: Tri-State Generation and Transmission Association, Inc.
Description: § 205(d) Rate Filing: Initial Filing of Rate Schedule FERC No. 352 to be effective 11/2/2022.
Filed Date: 12/23/22.
Accession Number: 20221223–5001.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–725–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Critical Natural Gas Infrastructure as Demand Response in the PJM Markets to be effective 2/22/2023.
Filed Date: 12/23/22.
Accession Number: 20221223–5010.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–726–000.
Applicants: Fresh Air Energy XXIII, LLC.
Description: Baseline eTariff Filing: Fresh Air Energy XXIII, LLC MBR Tariff to be effective 2/6/2023.
Filed Date: 12/23/22.
Accession Number: 20221223–5048.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–727–000.
Applicants: PGR 2022 Lessee 2, LLC.
Description: Baseline eTariff Filing: PGR 2022 Lessee 2, LLC MBR Tariff to be effective 2/6/2023.
Filed Date: 12/23/22.
Accession Number: 20221223–5051.
Comment Date: 5 p.m. ET 1/13/23.

Docket Numbers: ER23–728–000.
Applicants: PJM Interconnection, L.L.C.
Description: Tariff Amendment: Notice of Cancellation of ISA, SA No. 6590; Queue No. AC1–171 to be effective 10/18/2022.
Filed Date: 12/23/22.
Accession Number: 20221223–5083.
Comment Date: 5 p.m. ET 1/13/23.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

[FR Doc. 2022–28453 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. AD22–8–000, AD21–15–000]

Transmission Planning and Cost Management; Joint Federal-State Task Force on Electric Transmission; Notice Inviting Post-Technical Conference Comments

On October 6, 2022, the Federal Energy Regulatory Commission (Commission) convened a technical conference to discuss transmission planning and cost management for transmission facilities developed through local or regional transmission planning processes.

All interested persons are invited to file post-technical conference comments on issues raised during the conference that they believe would benefit from further discussion. In particular, parties are invited to provide comments on the questions listed below.[1] Commenters need not respond to all topics or questions asked, and they are not limited to the topics or questions posed.

Commenters may reference material previously filed in this docket, including the technical conference transcript, but are encouraged to avoid repetition or replication of previous material. In addition, commenters are encouraged, when possible, to provide examples and quantitative data in support of their answers. Comments must be submitted on or before 90 days from the date of this notice.

Comments may be filed electronically via the internet.[2] Instructions are available on the Commission's website *http://www.ferc.gov/docs-filing/efiling.asp.* For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll free at 1–866–208–3676, or for TTY, (202) 502–8659. Although the Commission strongly encourages electronic filing, documents may also be paper-filed. To paper-file, submissions sent via the U.S. Postal Service must be addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426. Submissions sent via any other carrier must be addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 12225 Wilkins Avenue, Rockville, MD 20852.

For more information about this Notice, please contact: John Riehl (Technical Information), Office of

[1] *Supplemental Notice of Technical Conference,* Docket No. AD22–8–000 (Oct. 4, 2022).

[2] *See* 18 CFR 385.2001(a)(1)(iii) (2021).

Energy Market Regulation, (202) 502–6026, *John.Riehl@ferc.gov.*

Dated: December 23, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

Post-Technical Conference Questions for Comment

Local Transmission Planning Under Order No. 890 and Planning for Asset Management [3] Projects

1. In Order No. 890, the Commission established nine transmission planning principles, including the coordination, openness, transparency, and information exchange principles.[4] The Commission adopted the transmission planning principles in Order No. 890 to remedy opportunities for undue discrimination in expansion of the transmission system on both a local and regional level.[5]

a. Do the existing Order No. 890 transmission planning requirements provide state regulators and other stakeholders with sufficient transparency into and information about public utility transmission providers' local transmission planning criteria and the resulting identification of transmission system needs? If not, please explain how the Commission could revise the coordination, openness, transparency, and information exchange principles in Order No. 890 to provide for enhanced transparency and information sharing. Further, please explain what, if any, additional transparency measures would assist state regulators and other stakeholders in understanding how public utility transmission providers develop their local transmission planning criteria, how those criteria drive local transmission needs, and how public utility transmission providers consider local transmission projects to address those needs.

b. Is there any information beyond that required under the Order No. 890 transmission planning principles that the Commission should consider requiring public utility transmission providers to provide in their local transmission planning processes? For example, should the Commission require that public utility transmission providers make available to state regulators and other stakeholders cost estimates used during transmission planning for all transmission facility alternatives considered to address the transmission needs, including, but not limited to, those transmission facilities that are chosen to address the local transmission planning criteria, or for a subset of those facility alternatives? What would be the advantages and disadvantages of such a requirement? If so, how should cost estimates used during transmission planning for these transmission facilities be calculated?

c. Are there barriers to state regulators and other stakeholders accessing the information that public utility transmission providers provide through their local transmission planning processes (*e.g.,* fees, background checks, etc.)? Do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented and to evaluate the public utility transmission providers' local transmission planning decisions? What actions could the Commission take to reduce any such barriers?

2. Order No. 890's requirements apply to transmission facilities that expand the transmission system, but do not apply to asset management projects, as defined above. However, some public utility transmission providers have processes that provide stakeholders with some transparency into their asset management decisions. For example, Pacific Gas & Electric's Stakeholder Transmission Asset Review (STAR) Process and Southern California Edison's Stakeholder Review Process (SRP) provide stakeholders with the opportunity to engage in a review of PG&E's and Southern California Edison's five-year plan for capital transmission projects so that stakeholders can understand the need for and anticipated costs of projects that are not reviewed in the California Independent System Operator Corp.'s (CAISO) transmission planning process.[6]

a. Should the Commission require public utility transmission providers to provide transparency concerning their asset management decisions? Are there any aspects of Pacific Gas & Electric's STAR Process or Southern California Edison's SRP that would be beneficial to consider? What other considerations are relevant to the transparency of asset management project decisions?

b. Are there barriers to state regulators and other stakeholders analyzing any additional information that the Commission could require public utility transmission providers to provide concerning their asset management projects? For example, do state regulators and other stakeholders have access to the expertise necessary to analyze the information presented? What actions could the Commission take to reduce any such barriers?

3. Could additional transparency facilitated by project-specific disclosure requirements or standardized filing requirements help increase the cost effectiveness of local transmission planning and asset management decisions? Examples include additional transparency and access to local planning criteria, utilities' rankings of their project priorities (subject to CEII protections), requirements for utilities to provide either publicly or to the Commission a standardized disclosure describing the need for a local transmission project or asset management project and why it is a cost-effective solution to that need before money is spent on the planned transmission project (other than any planning costs incurred), and a requirement for utilities to provide advance notice of a project nearing its end of life, among others. To the extent that such requirements may be appropriate, what specific requirements should the Commission impose? For example, for a standardized disclosure described above, should the Commission require utilities to provide such information to stakeholders as part of their local transmission planning process under Order No. 890, or should the Commission require utilities to make a filing with the Commission? At what point in the transmission planning process should these filings be made? Should any such filings be informational, or should they require Commission action? In designing any such requirements, how should the

[3] Asset Management refers to projects and activities that ''encompass the maintenance, repair, and replacement work done on existing transmission facilities as necessary to maintain a safe, reliable, and compliant grid based on existing topology.'' *See So. Cal. Edison Co,* 164 FERC ¶ 61,160 at n.55 (2018); *Cal. Pub. Util. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at n.119 (2018). Additionally, asset management projects or activities may result in an incidental increase in transmission capacity that is not reasonably severable from the asset management project or activity, and such incidental increase in transmission capacity would not render the asset management project or activity in question a transmission expansion that is subject to the transmission planning requirements of Order No. 890. *See So. Cal. Edison Co,* 164 FERC ¶ 61,160 at P 33 (2018); *Cal. Pub. Util. Comm'n* v. *Pac. Gas & Elec. Co.,* 164 FERC ¶ 61,161 at P 68 (2018).

[4] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 118 FERC ¶ 61,119, at P 444, *order on reh'g,* Order No. 890–A, 121 FERC ¶ 61,297 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[5] *Id.* PP 57–58, 421–422, 425.

[6] *See, e.g.,* PG&E, TO Tariff, PG&E Electric Tariff Volume No. 5 (0.0.0), Appendix IX, STAR Process (0.0.0). *See also So. Cal. Ed.,* Docket No. ER19–1553–005, at 2 (Dec. 8, 2020) (delegated letter order).

Commission weigh the administrative burden of those requirements against the transparency provided?

Project Implementation and Variance Analysis

4. In Order No. 1000, the Commission required public utility transmission providers to describe the circumstances and procedures by which they will reevaluate the regional transmission plan to determine if delays in the development of a regional or interregional transmission facility requires evaluation of alternative transmission solutions (reevaluation requirement).[7] To comply with this requirement, some public utility transmission providers voluntarily adopted a variance analysis process tied to changes in cost estimates to examine whether a regional transmission facility selected in a regional transmission plan for the purposes of cost allocation remains the more efficient or cost-effective transmission facility if its costs rise above estimates or if there are delays in that regional transmission facility's development.

a. Given that some RTOs/ISOs have voluntarily implemented variance analyses for regional and interregional transmission planning, are there certain best practices in regional and interregional transmission planning variance analyses that should be more widely adopted? Conversely, are there specific elements or characteristics of variance analyses used by certain public utility transmission providers that could be improved? Please describe.

b. What consequences should result if variance analyses show that a regional or interregional transmission facility's costs have increased above an established threshold since it was initially selected in a regional transmission plan for the purposes of cost allocation? What consequences should result if variance analyses show that a regional or interregional transmission facility's estimated benefits have eroded beyond an established threshold since it was initially selected in a regional transmission plan for the purposes of cost allocation?

c. Should the Commission require public utility transmission providers to perform variance analyses as part of their regional transmission planning processes? To what types of regional transmission projects should such a requirement apply?

[7] *Transmission Planning & Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at P 329 (2011).

d. Could variance analysis or similar mechanism be applied to facilitate cost management outside the context of regional or interregional transmission facilities subject to cost allocation under Order No. 1000 and, if so, should the Commission require it? What legal rationale would justify the requirement to use variance analysis? What level of increased costs or decreased benefits would merit evaluation through a variance analysis to determine whether a transmission project continues to be cost-effective? Would it be appropriate to apply a cost or benefits threshold below which or above which, respectively, such a requirement would not apply? Are there any categories of transmission projects for which this cost management method is not appropriate?

e. Who should be responsible for developing the cost estimates used in the variance analysis? The RTO/ISO, the public utility transmission provider, an Independent Transmission Monitor, or another entity? Should this role vary between non-RTO/ISO and RTO/ISO regions, and/or are there general guidelines with regard to independence that should be met for any entity developing cost estimates or bandwidths?

f. Can or should such an approach be designed in order to maximize benefits to consumers, as opposed to focusing only on reducing costs? For example, a given project modification might increase up-front costs of the project, but lower costs for customers in the long-run by enhancing project efficiency and thereby increasing anticipated economic benefits. Should any variance analysis mechanism required by the Commission be designed in a manner that encourages such investments, or at minimum does not inadvertently discourage them? If so, how?

Independent Transmission Monitor (ITM)

5. During the technical conference, many panelists argued in favor of an ITM to review and evaluate a wide range of elements of the transmission planning process, including the transmission planning criteria used to identify transmission facilities. However, others expressed concern that an ITM would be unnecessary or duplicative in light of other regulatory agencies or stakeholders. Given the divergence of views on the potential roles and responsibilities of an ITM, please respond to the following:

a. Please provide a concise but detailed job description for an ITM in both RTOs/ISOs and non-RTOs/ISOs. For example, should the ITM serve as a technical expert that publishes after-the-fact reports assessing public utility transmission providers' transmission plans? Should an ITM assist state regulators and other stakeholder with evaluating potential transmission facilities and their costs? Should an ITM participate in proceedings before the Commission? Should an ITM develop and monitor benchmark estimates of costs using data collected over time? Should an ITM assess continuing need for certain transmission projects? Should an ITM attend local and regional transmission planning meetings? Please list specific roles that would be appropriate for an ITM, and please explain at which stage of the transmission planning process those roles should be leveraged (*i.e.,* inputs and assumptions, planning study results, selection, cost allocation, project development).

b. What are the potential benefits of an ITM? Please describe with specificity, and address whether these benefits are particular to RTO/ISO or non-RTO/ISO regions, or present in both.

c. Are there specific challenges, including how the roles and responsibilities of the ITM relate to Commission jurisdiction, regarding the creation of an ITM, or the responsibilities that an ITM might have that the Commission should consider? If so, please describe.

d. What information would the ITM need access to in carrying out these responsibilities? Should the ITM have access to transmission planning and cost information, including CEII information? Please describe with specificity the information that the ITM should be able to review.

e. If an ITM were established, should the Commission periodically review the need for, role, and/or scope of that entity?

f. Would the ITM's functions potentially overlap with the functions of a public utility transmission provider, particularly in an RTO/ISO? If so, where would the overlap occur? Where should the ITM be housed, and what are the pros and cons of that arrangement (*e.g.,* internal or external independent entity similar to or incorporated within IMMs, an office within the Commission itself, or some other arrangement)? How should an ITM be funded?

g. How, if at all, should an ITM's role differ between RTO/ISO regions and non-RTO/ISO regions? What legal authority (or authorities) could the Commission rely on in establishing an ITM, and does that authority differ with respect to RTO/ISO and non-RTO/ISO regions? Should the Commission require an ITM in both RTOs/ISOs and non-

RTOs/ISOs? If so, please state the legal justification in both RTOs/ISOs and non-RTOs/ISOs. What implications does the Commission's scope of authority have with regard to the potential structure and duties of the ITM?

h. How often and at what stages of the local and regional transmission planning processes and interregional transmission coordination process should an ITM review and evaluate transmission facility cost information, if at all (*e.g.,* during the transmission planning cycle, during the development of the transmission facility, or following the completion of construction of the transmission facility)? What types of costs should an ITM review and evaluate (*e.g.,* capital costs, labor costs, etc.), if any? What should an ITM do with the information that is reviewed and evaluated?

i. Should the Commission establish a minimum threshold (*e.g.,* costs, voltage, etc.) for transmission facilities that would be reviewed by an ITM? If so, what should that threshold be and why? In RTO/ISO regions, should an ITM review only transmission facilities that address local transmission planning criteria and asset management transmission projects?

j. Should an ITM be subject to standards of conduct or other professional criteria? If so, what should those standards be?

Commission's Formula Rates and Prudence Practices

6. Under the MISO Protocol Orders,[8] the Commission required public utility transmission providers to include safeguards in their transmission formula rate protocols to provide transparency in the public utility transmission providers' implementation of their transmission formula rates, to ensure that input data is correct, and that their calculations are performed consistent with the formula.

a. What, if any, specific standard formula rate protocols that the Commission requires under the MISO Protocol Orders and other precedent should be revised, and how? For example, should the Commission require public utility transmission providers to provide additional time for state regulators and other stakeholders to review and respond to annual updates before they are submitted to the Commission?

7. Under the Commission's current prudence standard, the Commission presumes that a public utility transmission provider's expenditures are prudent in the absence of a challenge casting serious doubt on such prudence, and establishing serious doubt regarding prudence requires ''reliable, probative, and substantial evidence.'' [9]

a. Should the Commission alter the rebuttable presumption of prudence of expenditures in certain circumstances, such as with respect to specific types of expenditures (*e.g.,* asset management expenditures), where alternatives to transmission have not been considered, or where a state regulator has not reviewed a project for need and cost? If so, how should the standard be altered and in which circumstances?

8. Other than transparency criteria, are there ways that the Commission could consider local planning criteria that utilities use in determining how the prudence standard is applied to specific expenditures? For example, with respect to local transmission and/or asset management projects, should the Commission establish certain guidance for planning such projects and only apply the rebuttable presumption of prudence to projects that follow the Commission-determined guidelines for planning such projects? What are the pros and cons of that approach?

Federal and State Regulation of Transmission Facilities

9. Some panelists at the technical conference argued that there is a regulatory gap with regard to ensuring that a cost-effective mix of local, asset management, and regional reliability transmission projects is developed. Generally speaking, for such projects they contend that state siting processes, the formula rate process, and the Commission's prudence standard and existing transparency requirements, may not provide adequate assurance that utilities will choose a cost-effective mix of projects. Do you agree that there is a regulatory gap for local projects and/or asset management projects, and if so, why or why not? Does the presence or extent of a regulatory gap depend on the underlying state regulatory framework? If so, how? If you agree that one or more regulatory gaps exist, how should the Commission address these gaps? For example, should the Commission modify the prudence standard and/or formula rate protocols for transmission or asset management projects falling within such a regulatory gap? Should the Commission establish new transmission planning requirements to help ensure that such projects are cost-effective? In your response, please discuss whether the Commission's approach should depend on the underlying state regulatory framework. Also please discuss the extent to which your recommended reforms, standing alone, will address the perceived gaps, or whether they should or must be coupled with other solutions.

10. Some panelists argued that certain types of projects do not receive adequate state, regional, or federal scrutiny with regard to project prudence/need. For example, the Commission has held that asset management and end-of-life decisions are not subject to Order No. 890 planning requirements, and panelists highlighted that in some states such projects do not require a certificate of public convenience and necessity. Do you agree that some projects are not subject to adequate review, and if so, why or why not? What particular types of projects do not receive adequate scrutiny (if any), and should there be some form of heightened scrutiny for them? If so, what kind of heightened scrutiny would be appropriate, and how would that scrutiny be applied?

11. The Commission has authority over the justness and reasonableness of the rates for wholesale transmission service, including recovery of the costs of transmission facilities used in providing transmission service and the prudence of those expenditures, and has approved public utility transmission provider proposals to recover their costs of providing transmission service through formula rates. Under a formula rate, the Commission reviews and accepts as the rate a formula for calculating the utility's cost of service, including clear definitions of inputs to that formula and a process for updating rates every year as the utility's costs change. State regulators typically have authority to evaluate whether certain transmission facilities to be built within their state may be constructed (*i.e.,* whether to grant the proposed facility a Certificate of Public Convenience and Necessity (CPCN)), which may involve evaluation of the need for, and projected costs of, a proposed transmission facility.

a. Are there differences among the states' CPCN authorities and processes, and what is the extent of those differences?

b. Should the Commission consider relying on a state regulator's determination in a CPCN proceeding

[8] *Midwest Indep. Transmission Sys. Operator, Inc.,* 139 FERC ¶ 61,127 at P 9 (2013); *see also Midwest Indep. Transmission Sys. Operator, Inc.,* 143 FERC ¶ 61,149 (2013); *Midcontinent Indep. Sys. Operator, Inc.,* 146 FERC ¶ 61,212 (2014); and *Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,025 (2015) (collectively, MISO Protocol Orders).

[9] *Delmarva Power & Light Co.,* 172 FERC ¶ 61,175, at P 15 (2020) (citing *New Eng. Power Co.,* Opinion No. 231, 31 FERC ¶ 61,047 (1985)).

that a proposed transmission facility is in the public convenience and necessity when considering whether the costs of that transmission facility may be recovered through a formula rate? Should the Commission prohibit the recovery of transmission project costs through a formula rate if those projects have not been subject to a robust state CPCN process? Why or why not? Should the Commission accept as self-proving an attestation from state regulators that such a robust CPCN process is used in their state? If yes, are there specific factors or features of a state regulator's CPCN process that indicate whether a potential transmission facility has been robustly evaluated for need and cost? If not, are there other indicators (*e.g.,* other regulatory determinations, third-party analyses, legislative reports, etc.) that demonstrate that the need for and costs of a potential transmission facility have been robustly reviewed? What are the advantages and disadvantages of this approach?

c. If formula rate treatment is not permitted, how should costs related to the new transmission project or transmission facility be separated out for recovery in a stated rate proceeding (*e.g.,* should all costs related to the transmission facility be excluded from formula rate recovery, or only capital costs)? How could the timing of the state regulatory proceeding impact a public utility transmission provider's ability to file for cost recovery of proposed transmission facilities subject to CPCN review? How, if at all, would the inability to recover the costs of certain transmission facilities through a public utility transmission provider's formula rate impact its annual formula rate proceedings?

d. If the Commission determines that a potential transmission facility has not been robustly evaluated at the state level for need and cost, are there other regulatory requirements that the Commission could impose short of requiring a transmission facility's costs to be recovered through stated rates rather than formula rates? If so, what options are available and what are the pros and cons of those options?

Other Questions

12. Some panelists argued that the timing of cost management or oversight mechanisms is relevant to ensuring cost effectiveness, contending that cost scrutiny must be applied to decisions during the local or regional transmission planning phase in order to influence those decisions. Do you agree, and if so why or why not? What are the possibilities for facilitating timely cost management before money is spent on transmission projects (aside from planning costs)?

[FR Doc. 2022–28454 Filed 12–29–22; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL OP–OFA–050]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information 202–564–5632 or *https://www.epa.gov/nepa.*

Weekly receipt of Environmental Impact Statements (EIS) Filed December 19, 2022 10 a.m. EST Through December 23, 2022 10 a.m. EST Pursuant to 40 CFR 1506.9.

Notice

Section 309(a) of the Clean Air Act requires that EPA make public its comments on EISs issued by other Federal agencies. EPA's comment letters on EISs are available at: *https://cdxapps.epa.gov/cdx-enepa-II/public/action/eis/search.*

EIS No. 20220193, Final, FEMA, NJ, ADOPTION—Rebuild by Design—Hudson River (RBD–HR), Review Period Ends: 01/30/2023, Contact: John McKee 202–704–7160.

The Federal Emergency Management Agency (FEMA) has adopted the Department of Housing and Urban Development's Final EIS No. 20170101, filed 6/8/2017 with the Environmental Protection Agency. The FEMA was not a cooperating agency on this project. Therefore, republication of the document is necessary under Section 1506.3(c) of the CEQ regulations.

Amended Notice

EIS No. 20220175, Draft, BIA, DOI, OR, Coquille Indian Tribe Fee to Trust Gaming Facility Project, Comment Period Ends: 02/23/2023, Contact: Tobiah Mogavero 435–210–0509.

Revision to FR Notice Published 11/25/2022; Extending the Comment Period from 01/09/2023 to 02/23/2023.

Dated: December 23, 2022.

Cindy S. Barger,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 2022–28438 Filed 12–29–22; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Patient Safety Organizations: Voluntary Relinquishment for the Zephcare PSO

AGENCY: Agency for Healthcare Research and Quality (AHRQ), Department of Health and Human Services (HHS).

ACTION: Notice of delisting.

SUMMARY: The Patient Safety and Quality Improvement Final Rule (Patient Safety Rule) authorizes AHRQ, on behalf of the Secretary of HHS, to list as a patient safety organization (PSO) an entity that attests that it meets the statutory and regulatory requirements for listing. A PSO can be ''delisted'' by the Secretary if it is found to no longer meet the requirements of the Patient Safety and Quality Improvement Act of 2005 (Patient Safety Act) and Patient Safety Rule, when a PSO chooses to voluntarily relinquish its status as a PSO for any reason, or when a PSO's listing expires. AHRQ accepted a notification of proposed voluntary relinquishment from the Zephcare PSO, PSO number P0200, of its status as a PSO, and has delisted the PSO accordingly.

DATES: The delisting was effective at 12:00 Midnight ET (2400) on December 8, 2022.

ADDRESSES: The directories for both listed and delisted PSOs are ongoing and reviewed weekly by AHRQ. Both directories can be accessed electronically at the following HHS website: *https://www.pso.ahrq.gov/listed.*

FOR FURTHER INFORMATION CONTACT: Cathryn Bach, Center for Quality Improvement and Patient Safety, AHRQ, 5600 Fishers Lane, MS 06N100B, Rockville, MD 20857; Telephone (toll free): (866) 403–3697; Telephone (local): (301) 427–1111; TTY (toll free): (866) 438–7231; TTY (local): (301) 427–1130; Email: *pso@ahrq.hhs.gov.*

SUPPLEMENTARY INFORMATION:

Background

The Patient Safety Act, 42 U.S.C. 299b–21 to 299b–26, and the related Patient Safety Rule, 42 CFR part 3, published in the **Federal Register** on November 21, 2008 (73 FR 70732–70814), establish a framework by which individuals and entities that meet the definition of provider in the Patient Safety Rule may voluntarily report information to PSOs listed by AHRQ, on a privileged and confidential basis, for the aggregation and analysis of patient safety work product.

The Patient Safety Act authorizes the listing of PSOs, which are entities or component organizations whose mission and primary activity are to conduct activities to improve patient safety and the quality of health care delivery.

HHS issued the Patient Safety Rule to implement the Patient Safety Act. AHRQ administers the provisions of the Patient Safety Act and Patient Safety Rule relating to the listing and operation of PSOs. The Patient Safety Rule authorizes AHRQ to list as a PSO an entity that attests that it meets the statutory and regulatory requirements for listing. A PSO can be ''delisted'' if it is found to no longer meet the requirements of the Patient Safety Act and Patient Safety Rule, when a PSO chooses to voluntarily relinquish its status as a PSO for any reason, or when a PSO's listing expires. Section 3.108(d) of the Patient Safety Rule requires AHRQ to provide public notice when it removes an organization from the list of PSOs.

AHRQ has accepted a notification of proposed voluntary relinquishment from the Zephcare PSO to voluntarily relinquish its status as a PSO. Accordingly, the Zephcare PSO, PSO number P0200, was delisted effective at 12:00 Midnight ET (2400) on December 8, 2022.

Zephcare PSO has patient safety work product (PSWP) in its possession. The PSO will meet the requirements of section 3.108(c)(2)(i) of the Patient Safety Rule regarding notification to providers that have reported to the PSO and of section 3.108(c)(2)(ii) regarding disposition of PSWP consistent with section 3.108(b)(3). According to section 3.108(b)(3) of the Patient Safety Rule, the PSO has 90 days from the effective date of delisting and revocation to complete the disposition of PSWP that is currently in the PSO's possession.

More information on PSOs can be obtained through AHRQ's PSO website at *https://www.pso.ahrq.gov*.

Dated: December 23, 2022.

Marquita Cullom,

Associate Director.

[FR Doc. 2022–28432 Filed 12–29–22; 8:45 am]

BILLING CODE 4160–90–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency for Healthcare Research and Quality

Solicitation for Nominations for Members of the U.S. Preventive Services Task Force (USPSTF)

AGENCY: Agency for Healthcare Research and Quality (AHRQ), HHS.

ACTION: Solicits nominations for new members of the USPSTF.

SUMMARY: The Agency for Healthcare Research and Quality (AHRQ) invites nominations of individuals qualified to serve as members of the U.S. Preventive Services Task Force (USPSTF).

DATES: Nominations must be received electronically by March 15th of a given year to be considered for appointment to begin in January of the following year.

ADDRESSES: Submit your responses electronically via: *https://uspstfnominations.ahrq.gov/register.*

FOR FURTHER INFORMATION CONTACT: Lydia Hill at (301) 427–1587.

SUPPLEMENTARY INFORMATION:

Arrangement for Public Inspection

Nominations and applications are kept on file at the Center for Evidence and Practice Improvement, AHRQ, and are available for review during business hours. AHRQ does not reply to individual nominations, but considers all nominations in selecting members. Information regarded as private and personal, such as a nominee's social security number, home and email addresses, home telephone and fax numbers, or names of family members will not be disclosed to the public in accord with the Freedom of Information Act. 5 U.S.C. 552(b)(6); 45 CFR 5.31(f).

Nomination Submissions

Nominations must be submitted electronically, and should include:

1. The applicant's current curriculum vitae and contact information, including mailing address, and email address; and

2. A letter explaining how this individual meets the qualification requirements and how he or she would contribute to the USPSTF. The letter should also attest to the nominee's willingness to serve as a member of the USPSTF.

AHRQ will later ask people under serious consideration for USPSTF membership to provide detailed information that will permit evaluation of possible significant conflicts of interest. Such information will concern matters such as financial holdings, consultancies, non-financial scientific interests, and research grants or contracts.

To obtain a diversity of perspectives, AHRQ particularly encourages nominations of women, members of underrepresented populations, and persons with disabilities. Interested individuals can nominate themselves. Organizations and individuals may nominate one or more people qualified for membership on the USPSTF at any time. Individuals nominated prior to March 15, 2022, who continue to have interest in serving on the USPSTF should be re-nominated.

Qualification Requirements

To qualify for the USPSTF and support its mission, an applicant or nominee should, at a minimum, demonstrate knowledge, expertise, and national leadership in the following areas:

1. The critical evaluation of research published in peer-reviewed literature and in the methods of evidence review;

2. Clinical prevention, health promotion and primary health care; and

3. Implementation of evidence-based recommendations in clinical practice including at the clinician-patient level, practice level, and health-system level.

Additionally, the Task Force benefits from members with expertise in the following areas:

- Public Health
- Health Equity and The Reduction of Health Disparities
- Application of Science to Health Policy
- Decision modeling
- Dissemination and Implementation
- Behavioral Medicine/Clinical Health Psychology
- Communication of Scientific Findings to Multiple Audiences Including Health Care Professionals, Policy Makers, and the General Public.

Candidates with experience and skills in any of these areas should highlight them in their nomination materials.

Applicants must have no substantial conflicts of interest, whether financial, professional, or intellectual, that would impair the scientific integrity of the work of the USPSTF and must be willing to complete regular conflict of interest disclosures.

Applicants must have the ability to work collaboratively with a team of diverse professionals who support the mission of the USPSTF. Applicants must have adequate time to contribute substantively to the work products of the USPSTF.

Nominee Selection

Nominated individuals will be selected for the USPSTF on the basis of how well they meet the required qualifications and the current expertise needs of the USPSTF. It is anticipated that new members will be invited to serve on the USPSTF beginning in January, 2024. All nominated individuals will be considered; however, strongest consideration will be given to individuals with demonstrated training and expertise in the areas of Internal Medicine, Pediatrics, Geriatrics, and Family Medicine. AHRQ will retain and may consider for future vacancies nominations received this year and not selected during this cycle.

Some USPSTF members without primary health care clinical experience may be selected based on their expertise in methodological issues such as meta-analysis, analytic modeling, or clinical epidemiology. For individuals with clinical expertise in primary health care, additional qualifications in methodology would enhance their candidacy.

Background

Under Title IX of the Public Health Service Act, AHRQ is charged with enhancing the quality, appropriateness, and effectiveness of health care services and access to such services. 42 U.S.C. 299(b). AHRQ accomplishes these goals through scientific research and promotion of improvements in clinical practice, including clinical prevention of diseases and other health conditions. See 42 U.S.C. 299(b).

The USPSTF, an independent body of experts in prevention and evidence-based medicine, works to improve the health of all Americans by making evidence-based recommendations about the effectiveness of clinical preventive services and health promotion. The recommendations made by the USPSTF address clinical preventive services for adults and children, and include screening tests, counseling services, and preventive medications.

The USPSTF was first established in 1984 under the auspices of the U.S. Public Health Service. Currently, the USPSTF is convened by the Director of AHRQ, and AHRQ provides ongoing scientific, administrative, and dissemination support for the USPSTF's operation. See 42 U.S.C. 299b–4(a)(1). USPSTF members are invited to serve four year terms. New members are selected each year to replace those members who are completing their appointments.

The USPSTF rigorously evaluates the effectiveness of clinical preventive services and formulating or updating recommendations regarding the appropriate provision of preventive services. Current USPSTF recommendations and associated evidence reviews are available on the internet (*www.uspreventiveservicestaskforce.org*).

USPSTF members meet three times a year for two days in the Washington, DC area or virtually if necessary. A significant portion of the USPSTF's work occurs between meetings during conference calls and via email discussions. Member duties include prioritizing topics, designing research plans, reviewing and commenting on systematic evidence reviews, discussing evidence and making recommendations on preventive services, reviewing stakeholder comments, drafting final recommendation documents, and participating in workgroups on specific topics and methods. Members can expect to receive frequent emails, can expect to participate in multiple conference calls each month, and can expect to have periodic interaction with stakeholders. AHRQ estimates that members devote approximately 250 hours a year outside of in-person meetings to their USPSTF duties. The members are all volunteers and do not receive any compensation beyond support for travel to attend the thrice yearly meetings and trainings.

Dated: December 27, 2022.

Marquita Cullom,

Associate Director.

[FR Doc. 2022–28469 Filed 12–29–22; 8:45 am]

BILLING CODE 4160–90–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier: CMS–10744]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Centers for Medicare & Medicaid Services, Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: The Centers for Medicare & Medicaid Services (CMS) is announcing an opportunity for the public to comment on CMS' intention to collect information from the public. Under the Paperwork Reduction Act of 1995 (PRA), federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, and to allow a second opportunity for public comment on the notice. Interested persons are invited to send comments regarding the burden estimate or any other aspect of this collection of information, including the necessity and utility of the proposed information collection for the proper performance of the agency's functions, the accuracy of the estimated burden, ways to enhance the quality, utility, and clarity of the information to be collected, and the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

DATES: Comments on the collection(s) of information must be received by the OMB desk officer by January 30, 2023.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

To obtain copies of a supporting statement and any related forms for the proposed collection(s) summarized in this notice, please access the CMS PRA website by copying and pasting the following web address into your web browser: *https://www.cms.gov/Regulations-and-Guidance/Legislation/PaperworkReductionActof1995/PRA-Listing.*

FOR FURTHER INFORMATION CONTACT: William Parham at (410) 786–4669.

SUPPLEMENTARY INFORMATION: Under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3520), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. The term ''collection of information'' is defined in 44 U.S.C. 3502(3) and 5 CFR 1320.3(c) and includes agency requests or requirements that members of the public submit reports, keep records, or provide information to a third party. Section 3506(c)(2)(A) of the PRA (44 U.S.C. 3506(c)(2)(A)) requires Federal agencies to publish a 30-day notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, before submitting the collection to OMB for approval. To comply with this requirement, CMS is publishing this notice that summarizes the following proposed collection(s) of information for public comment:

1. *Type of Information Collection Request:* Revision of a currently

approved collection; *Title:* Medicare Durable Medical Equipment, Prosthetics, Orthotics, and Supplies (DMEPOS) Competitive Bidding Program—Contracting Forms; *Use:* Since 1989, Medicare has been paying for durable medical equipment, prosthetics, orthotics, and supplies (DMEPOS) (other than customized items) using fee schedule amounts that are calculated for each item or category of DMEPOS identified by a Healthcare Common Procedure Coding System (HCPCS) code. Payments are based on the average DMEPOS supplier charges on Medicare claims from 1986 and 1987 and are updated annually on a factor legislated by Congress. For many years, the Government Accountability Office (GAO) and the Office of Inspector General (OIG) of the United States (U.S.) Department of Health and Human Services (HHS) have reported that these fees are often highly inflated and that Medicare has paid higher than market rates for several different types of DMEPOS. Due to reports of Medicare overpayment of DMEPOS, Congress required that the Centers for Medicare & Medicaid Services (CMS) conduct a competitive bidding demonstration project for these items. Accordingly, CMS implemented a demonstration project for this program from 1999–2002 which produced significant savings for beneficiaries and taxpayers without hindering access to DMEPOS and related services. Shortly after the successful competitive bidding demonstrations, Congress passed the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (MMA) and mandated a phased-in approach to implement this program over the course of several years beginning in 2007 in 10 metropolitan statistical areas (MSAs). This statute specifically required the Secretary to establish and implement programs under which competitive bidding areas (CBAs) are established throughout the U.S. for contract award purposes for the furnishing of certain competitively priced items and services for which payment is made under Medicare Part B. This program is commonly known as the Medicare DMEPOS Competitive Bidding Program (the Program).

CMS conducted its first round of bidding, Round 1, for the Program in 2007 with the help of its contractor, the Competitive Bidding Implementation Contractor (CBIC). CMS published a Request for Bids (RFB) and instructions for DMEPOS suppliers to submit their bids to participate in the Program. During this first round of bidding, DMEPOS suppliers from across the U.S. submitted bids to furnish competitively bid item(s) to Medicare beneficiaries residing or traveling to Round 1 CBAs. CMS evaluated these bids and contracted with those bidders that met all program requirements. Round 1 was successfully implemented on July 1, 2008.

On July 15, 2008, however, Congress delayed the Program in section 154 of the Medicare Improvements for Patients and Providers Act of 2008 (MIPPA). MIPPA mandated certain changes to the Program which included, but was not limited to: a delay of Round 1 (competition to begin in 2009) and Round 2 of the Program (competition to begin in 2011 in 70 specific MSAs); the exclusion of Puerto Rico and negative pressure wound therapy from Round 1 and Group 3 complex rehabilitative power wheelchairs from all rounds of competition; a process for providing feedback to bidders regarding missing financial documentation; and a requirement for contract suppliers to disclose to CMS information regarding subcontracting relationships. Section 154 of MIPPA specified that the competition for national mail-order (NMO) items and services may be phased in after 2010. This section of MIPPA also specified that competitions to phase-in additional areas could occur after 2011. As required by MIPPA, CMS conducted the competition for the Round 1 Rebid in 2009. The Round 1 Rebid contracts and prices became effective on January 1, 2011. The Affordable Care Act (ACA), enacted on March 23, 2010, expanded the Round 2 competition by adding an additional 21 MSAs, bringing the total MSAs for Round 2 to 91. The competition for Round 2 began in December 2011. CMS also began a NMO competition for diabetes testing supplies (DTS) at the same time as Round 2. The Round 2 and NMO DTS contracts and prices were implemented on July 1, 2013.

The MMA requires the Secretary to recompete contracts not less often than once every three years. The Round 1 Rebid contract period for all product categories except NMO DTS expired on December 31, 2013. (Round 1 Rebid contracts for NMO DTS ended on December 31, 2012.) The competition for the Round 1 Recompete began in August of 2012 and contracts and prices became effective on January 1, 2014. The Round 1 Recompete contract period expired on December 31, 2016. Round 1 2017 contracts were effective on January 1, 2017, and expired on December 31, 2018. Round 2 and NMO DTS contracts and prices expired on June 30, 2016. Round 2 Recompete and the NMO DTS Recompete contracts became effective on July 1, 2016, and expired on December 31, 2018.

On October 31, 2018, CMS issued a final rule (CMS–1691–F) requiring changes to bidding and pricing methodologies to be implemented under the next round of the Program. As a result, starting January 1, 2019, there was a temporary gap in the entire Program that lasted two years until December 31, 2020. When the program resumed in January 2021, CMS implemented a consolidated round of competition to include most Round 1 2017 and Round 2 Recompete CBAs for Round 2021. However, due to the 2019 novel coronavirus (COVID–19) pandemic, and the unexpected bid evaluation results, CMS only awarded Round 2021 contracts for two product categories: Off-The-Shelf (OTS) Back and OTS Knee Braces. As a result, this Paperwork Reduction Act (PRA) package reflects a significant reduction in burden, compared to previous packages, for Round 2021 which was implemented on January 1, 2021, and will concluded on December 31, 2023. This iteration of the package currently approved under OMB control number 0938–1408 is based on data from the first year of Round 2021 (January 1, 2021–December 31, 2021). *Form Number:* CMS–10744 (OMB control number: 0938–1408); *Frequency:* Occasionally; *Affected Public:* Private sector (Business or other for profits and Not-for-profit institutions); *Number of Respondents:* 179; *Total Annual Responses:* 121,407; *Total Annual Hours:* 97,069. (For policy questions regarding this collection contact Joe Bryson at 410–786–2986.)

Dated: December 27, 2022.

William N. Parham, III,

Director, Paperwork Reduction Staff, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2022–28466 Filed 12–29–22; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Children and Families

Submission for Office of Management and Budget Review; Tribal Maternal, Infant, and Early Childhood Home Visiting Program: Guidance for Submitting an Annual Report to the Secretary (Office of Management and Budget #0970–0409)

AGENCY: Office of Early Childhood Development, Administration for

Children and Families, U.S. Department of Health and Human Services.

ACTION: Request for public comments.

SUMMARY: The Administration for Children and Families (ACF), Office of Early Childhood Development (ECD) is requesting revisions to the Tribal Maternal, Infant, and Early Childhood Home Visiting Program (Tribal MIECHV) Guidance for Submitting Reports to the Secretary (Office of Management and Budget (OMB) #0970–0409; expiration September 30, 2024). Guidance under this OMB number includes that for an annual report and that for a final report. This request is for review of the final report guidance. There are no changes proposed to the guidance for the annual report.

DATES: *Comments due within 30 days of publication.* OMB must make a decision about the collection of information between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment is best assured of having its full effect if OMB receives it within 30 days of publication.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function. You can also obtain copies of the proposed collection of information by emailing *infocollection@acf.hhs.gov.* Identify all emailed requests by the title of the information collection.

SUPPLEMENTARY INFORMATION:

Description: Section 511(e)(8)(A) of Title V of the Social Security Act requires that grantees under the MIECHV Program for states and jurisdictions submit an annual and a final report to the Secretary of Health and Human Services regarding the program and activities carried out under the program, including such data and information as the Secretary shall require. Section 511(h)(2)(A) further states that the requirements for the MIECHV grants to tribes, tribal organizations, and urban Indian organizations are to be consistent, to the greatest extent practicable, with the requirements for grantees under the MIECHV Program for states and jurisdictions.

ECD, in collaboration with the Health Resources and Services Administration, Maternal and Child Health Bureau awarded grants for the Tribal MIECHV Program (Tribal Home Visiting) to support cooperative agreements to conduct community needs assessments; plan for and implement high-quality, culturally relevant, evidence-based home visiting programs in at-risk tribal communities; establish, measure, and report on progress toward meeting performance measures in six legislatively mandated benchmark areas; and conduct rigorous evaluation activities to build the knowledge base on home visiting among Native populations.

After the first grant year, Tribal Home Visiting grantees must comply with the requirement to submit an annual report to the Secretary that should feature activities carried out under the program during the past reporting period, and a final report to the Secretary during the final year of their grant. To assist grantees with meeting these requirements, ACF created guidance for grantees to use when writing their reports. The annual and final report guidance specifies that grantees must address the following:

- Update and reflections on meeting Home Visiting Program Goals and Objectives
- Update and reflections on Home Visiting Programs in Targeted Community(ies)
- Update and reflections on meeting Legislatively Mandated Benchmark Requirements
- Update and reflections on Rigorous Evaluation Activities
- Update and reflections on Home Visiting Program Continuous Quality Improvement (CQI) Efforts
- Update and reflections on Dissemination Activities
- Update and reflections on Administration of Home Visiting Program
- Update and reflections on Technical Assistance Needs

Previously, the guidance included information about both the annual and the final reports from grantees. In 2021, ECD separated out the annual report guidance and received OMB approval for that in September 2021. ECD is now requesting review of guidance specific to the final report.

Respondents: Tribal Home Visiting Managers (information collection does not include direct interaction with individuals or families that receive the services).

ANNUAL BURDEN ESTIMATES

Instrument	Total number of respondents	Annual number of responses per respondent	Average burden hours per response	Annual burden hours
Annual Report to the Secretary	30	1	25	750
Final Report to the Secretary	30	* .33	25	248

* Note that this is estimated to be .33 because grantees provide one final report over the three-year approval period.

Estimated Total Annual Burden Hours: 998.

Authority: Title V of the Social Security Act, sections 511(e)(8)(A) and 511(h)(2)(A).

Mary B. Jones,

ACF/OPRE Certifying Officer.

[FR Doc. 2022–28427 Filed 12–29–22; 8:45 am]

BILLING CODE 4184–43–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Children and Families

Submission for OMB Review; Temporary Assistance for Needy Families (TANF) Financial Report, ACF–196T (OMB #0970–0345)

AGENCY: Office of Family Assistance, Administration for Children and Families, U.S. Department of Health and Human Services.

ACTION: Request for public comments.

SUMMARY: The Administration for Children and Families (ACF) is requesting a 3-year extension of the Temporary Assistance for Needy Families (TANF) Financial Report, Form ACF–196T (Office of Management and Budget (OMB) #0970–0345, expiration April 30, 2023). ACF is proposing minor

updates to the form to remove a reporting line-item reference that was associated with an expired program expenditure and minor edits to the instructions and formatting to better the presentation of the document.

DATES: *Comments due within 30 days of publication.* OMB must make a decision about the collection of information between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, a comment is best assured of having its full effect if OMB receives it within 30 days of publication.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function. You can also obtain copies of the proposed collection of information by emailing *infocollection@acf.hhs.gov.* Identify all emailed requests by the title of the information collection.

SUPPLEMENTARY INFORMATION:

Description: Grantees of the TANF program are required by statute to report financial data on a quarterly basis. Form ACF–196T is used by tribal agencies administering the TANF program to report these quarterly expenditure data and to request quarterly grant funds. Failure to collect the data would seriously compromise the Office of Family Assistance and ACF's ability to monitor TANF expenditures and compliance with statutory requirements. These data are also needed to estimate outlays and to prepare reports and budget submissions for Congress.

Respondents: Tribal agencies receiving a direct grant from OFA to administer a TANF program.

ANNUAL BURDEN ESTIMATES

Instrument	Total number of respondents	Annual number of responses per respondent	Average burden hours per response	Annual burden hours
TANF Financial Report, Form ACF–196T	51	4	1.5	306

Estimated Total Annual Burden Hours: 306.

Authority: Social Security Act, Section 409 and 411; 45 CFR 286.245–286.285.

Mary B. Jones,

ACF/OPRE Certifying Officer.

[FR Doc. 2022–28423 Filed 12–29–22; 8:45 am]

BILLING CODE 4184–36–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2022–N–2375]

Authorization of Emergency Use of an In Vitro Diagnostic Device in Response to an Outbreak of Mpox; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the issuance of an Emergency Use Authorization (EUA) (the Authorization) under the Federal Food, Drug, and Cosmetic Act (FD&C Act) in response to an outbreak of mpox. FDA has issued an Authorization for an in vitro diagnostic device as requested by Roche Molecular Systems, Inc. The Authorization contains, among other things, conditions on the emergency use of the authorized product. The Authorization follows the August 9, 2022, determination by the Secretary of Health and Human Services (HHS) that there is a public health emergency, or a significant potential for a public health emergency, that affects, or has a significant potential to affect, national security or the health and security of U.S. citizens living abroad, and that involves monkeypox virus. On the basis of such determination, the Secretary of HHS declared, on September 7, 2022, that circumstances exist justifying the authorization of emergency use of in vitro diagnostics for detection and/or diagnosis of infection with the monkeypox virus, including in vitro diagnostics that detect and/or diagnose infection with non-variola *Orthopoxvirus,* pursuant to the FD&C Act, subject to terms of any authorization issued under that section. The Authorization, which includes an explanation of the reasons for issuance, is reprinted in this document.

DATES: The Authorization is effective as of November 15, 2022.

ADDRESSES: Submit written requests for a single copy of the EUA to the Office of Counterterrorism and Emerging Threats, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 1, Rm. 4338, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your request or include a Fax number to which the Authorization may be sent. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the Authorization.

FOR FURTHER INFORMATION CONTACT: Jennifer Ross, Office of Counterterrorism and Emerging Threats, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 1, Rm. 4332, Silver Spring, MD 20993–0002, 301–796–8510 (this is not a toll-free number).

SUPPLEMENTARY INFORMATION:

I. Background

Section 564 of the FD&C Act (21 U.S.C. 360bbb–3) allows FDA to strengthen public health protections against biological, chemical, nuclear, and radiological agents. Among other things, section 564 of the FD&C Act allows FDA to authorize the use of an unapproved medical product or an unapproved use of an approved medical product in certain situations. With this EUA authority, FDA can help ensure that medical countermeasures may be used in emergencies to diagnose, treat, or prevent serious or life-threatening diseases or conditions caused by biological, chemical, nuclear, or radiological agents when there are no adequate, approved, and available alternatives (among other criteria).

II. Criteria for EUA Authorization

Section 564(b)(1) of the FD&C Act provides that, before an EUA may be issued, the Secretary of HHS must declare that circumstances exist justifying the authorization based on one of the following grounds: (1) a determination by the Secretary of Homeland Security that there is a domestic emergency, or a significant potential for a domestic emergency, involving a heightened risk of attack with a biological, chemical, radiological, or nuclear agent or agents; (2) a determination by the Secretary of Defense that there is a military emergency, or a significant potential for a military emergency, involving a heightened risk to U.S. military forces, including personnel operating under the authority of title 10 or title 50, U.S. Code, of attack with (A) a biological, chemical, radiological, or nuclear agent or agents or (B) an agent or agents that may cause, or are otherwise associated with, an imminently life-threatening and specific risk to U.S. military forces;[1] (3) a determination by the Secretary of HHS that there is a public health emergency, or a significant potential for a public health emergency, that affects, or has a significant potential to affect, national security or the health and security of U.S. citizens living abroad, and that involves a biological, chemical, radiological, or nuclear agent or agents, or a disease or condition that may be attributable to such agent or agents; or (4) the identification of a material threat by the Secretary of Homeland Security pursuant to section 319F–2 of the Public Health Service (PHS) Act (42 U.S.C. 247d–6b) sufficient to affect national security or the health and security of U.S. citizens living abroad.

Once the Secretary of HHS has declared that circumstances exist justifying an authorization under section 564 of the FD&C Act, FDA may authorize the emergency use of a drug, device, or biological product if the Agency concludes that the statutory criteria are satisfied. Under section 564(h)(1) of the FD&C Act, FDA is required to publish in the **Federal Register** a notice of each authorization, and each termination or revocation of an authorization, and an explanation of the reasons for the action. Under section 564(h)(1) of the FD&C Act, revisions to an authorization shall be made available on the internet website of FDA. Section 564 of the FD&C Act permits FDA to authorize the introduction into interstate commerce of a drug, device, or biological product intended for use in an actual or potential emergency when the Secretary of HHS has declared that circumstances exist justifying the authorization of emergency use.

[1] In the case of a determination by the Secretary of Defense, the Secretary of HHS shall determine within 45 calendar days of such determination, whether to make a declaration under section 564(b)(1) of the FD&C Act, and, if appropriate, shall promptly make such a declaration.

Products appropriate for emergency use may include products and uses that are not approved, cleared, or licensed under sections 505, 510(k), 512, or 515 of the FD&C Act (21 U.S.C. 355, 360(k), 360b, or 360e) or section 351 of the PHS Act (42 U.S.C. 262), or conditionally approved under section 571 of the FD&C Act (21 U.S.C. 360ccc).

FDA may issue an EUA only if, after consultation with the HHS Assistant Secretary for Preparedness and Response, the Director of the National Institutes of Health, and the Director of the Centers for Disease Control and Prevention (to the extent feasible and appropriate given the applicable circumstances), FDA[2] concludes: (1) that an agent referred to in a declaration of emergency or threat can cause a serious or life-threatening disease or condition; (2) that, based on the totality of scientific evidence available to FDA, including data from adequate and well-controlled clinical trials, if available, it is reasonable to believe that (A) the product may be effective in diagnosing, treating, or preventing (i) such disease or condition or (ii) a serious or life-threatening disease or condition caused by a product authorized under section 564, approved or cleared under the FD&C Act, or licensed under section 351 of the PHS Act, for diagnosing, treating, or preventing such a disease or condition caused by such an agent and (B) the known and potential benefits of the product, when used to diagnose, prevent, or treat such disease or condition, outweigh the known and potential risks of the product, taking into consideration the material threat posed by the agent or agents identified in a declaration under section 564(b)(1)(D) of the FD&C Act, if applicable; (3) that there is no adequate, approved, and available alternative to the product for diagnosing, preventing, or treating such disease or condition; (4) in the case of a determination described in section 564(b)(1)(B)(ii) of the FD&C Act, that the request for emergency use is made by the Secretary of Defense; and (5) that such other criteria as may be prescribed by regulation are satisfied.

No other criteria for issuance have been prescribed by regulation under section 564(c)(4) of the FD&C Act.

[2] The Secretary of HHS has delegated the authority to issue an EUA under section 564 of the FD&C Act to the Commissioner of Food and Drugs.

III. The Authorization

The Authorization follows the August 9, 2022, determination by the Secretary of HHS that there is a public health emergency, or a significant potential for a public health emergency, that affects, or has a significant potential to affect, national security or the health and security of U.S. citizens living abroad, and that involves monkeypox virus. Notice of the Secretary's determination was provided in the **Federal Register** on August 15, 2022 (87 FR 50090). On the basis of such determination, the Secretary of HHS declared, on September 7, 2022, that circumstances exist justifying the authorization of emergency use of in vitro diagnostics for detection and/or diagnosis of infection with the monkeypox virus, including in vitro diagnostics that detect and/or diagnose infection with non-variola *Orthopoxvirus,* pursuant to section 564 of the FD&C Act, subject to the terms of any authorization issued under that section. Notice of the Secretary's declaration was provided in the **Federal Register** on September 13, 2022 (87 FR 56074). On October 7, 2022, having concluded that the criteria for issuance of the Authorization under section 564(c) of the FD&C Act are met, FDA issued an EUA to Roche Molecular Systems, Inc. for the cobas MPXV for use on the cobas 6800/8800 Systems (cobas MPXV), subject to the terms of the Authorization. The Authorization, which is included below in its entirety after section IV of this document (not including the authorized versions of the fact sheets and other written materials), provides an explanation of the reasons for issuance, as required by section 564(h)(1) of the FD&C Act. Any subsequent revision to the Authorization can be found on FDA's web page at: *https://www.fda.gov/emergency-preparedness-and-response/mcm-legal-regulatory-and-policy-framework/emergency-use-authorization.*

IV. Electronic Access

An electronic version of this document and the full text of the Authorization is available on the internet at: *https://www.fda.gov/emergency-preparedness-and-response/mcm-legal-regulatory-and-policy-framework/emergency-use-authorization.*

BILLING CODE 4164–01–P

November 15, 2022

Michael Lynch
Manager, Regulatory Affairs
Roche Molecular Systems, Inc.
4300 Hacienda Drive
Pleasanton, CA 94588

Device:	cobas MPXV for use on the cobas 6800/8800 Systems (cobas MPXV)
EUA Number:	EUA220459
Company:	Roche Molecular Systems, Inc.
Indication:	This test is authorized for the qualitative detection of DNA from monkeypox virus (MPXV, clade I/II)[1] in human lesion swab specimens (i.e., swabs of acute pustular or vesicular rash) from individuals suspected of monkeypox virus infection by their healthcare provider.
	Emergency use of this test is limited to authorized laboratories.
Authorized Laboratories:	Laboratories certified under the Clinical Laboratory Improvement Amendments of 1988 (CLIA), 42 U.S.C. §263a, that meet the requirements to perform moderate or high complexity tests.

Dear Mr. Lynch:

This letter is in response to your[2] request that the Food and Drug Administration (FDA) issue an Emergency Use Authorization (EUA) for emergency use of your product,[3] pursuant to Section 564 of the Federal Food, Drug, and Cosmetic Act (the Act) (21 U.S.C. §360bbb-3).

On August 9, 2022, pursuant to Section 564(b)(1)(C) of the Act, the Secretary of the Department of Health and Human Services (HHS) determined that there is a public health

[1] On August 12, 2022, following a meeting convened by the World Health Organization (WHO) monkeypox virus variants were renamed to align with current best practices under the International Classification of Diseases and the WHO Family of International Health Related Classifications (WHO-FIC). This letter will refer to the former Congo Basin (Central African) clade as clade one (I) and the former West African clade as clade two (II). Refer to: https://www.who.int/news/item/12-08-2022-monkeypox--experts-give-virus-variants-new-names.
[2] For ease of reference, this letter will use the term "you" and related terms to refer to Roche Molecular Systems, Inc.
[3] For ease of reference, this letter will use the term "your product" to refer to the cobas MPXV for use on the cobas 6800/8800 Systems (cobas MPXV) used for the indication identified above.

emergency, or a significant potential for a public health emergency, that affects or has a significant potential to affect national security or the health and security of United States citizens living abroad that involves monkeypox virus.[4] Pursuant to Section 564 of the Act, and on the basis of such determination, the Secretary of HHS then declared on September 7, 2022 that circumstances exist justifying the authorization of emergency use of in vitro diagnostics for detection and/or diagnosis of infection with the monkeypox virus, including in vitro diagnostics that detect and/or diagnose infection with non-variola *Orthopoxvirus*, subject to the terms of any authorization issued under Section 564(a) of the Act.[5]

FDA considered the totality of scientific information available in authorizing the emergency use of your product for the indication above. A summary of the performance information FDA relied upon is contained in the "cobas MPXV Qualitative assay for use on the cobas 6800/8800 Systems" Instructions for Use. There is an FDA-cleared test for the qualitative detection of non-variola *Orthopoxvirus*, that includes monkeypox virus, but this is not an adequate and available alternative to your product.[6]

Having concluded that the criteria for issuance of this authorization under Section 564(c) of the Act are met, I am authorizing the emergency use of your product, described in the Scope of Authorization of this letter (Section II), subject to the terms of this authorization.

I. Criteria for Issuance of Authorization

I have concluded that the emergency use of your product meets the criteria for issuance of an authorization under Section 564(c) of the Act, because I have concluded that:

1. The monkeypox virus can cause a serious or life-threatening disease or condition, to humans infected by this virus;

2. Based on the totality of scientific evidence available to FDA, it is reasonable to believe that your product may be effective in diagnosing infection with the monkeypox virus, and that the known and potential benefits of your product when used for diagnosing monkeypox virus, outweigh the known and potential risks of your product; and

3. There is no adequate, approved, and available alternative to the emergency use of your product.[7]

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[4] 87 FR 50090 (August 15, 2022)
[5] 87 FR 56074 (September 13, 2022)
[6] To date, the FDA-cleared CDC Non-variola *Orthopoxvirus* Real-time PCR Primer and Probe Set (Product Code: PBK; DEN070001, K181205, K221658, K221834, K222558) is the only test available in the United States with FDA clearance for the detection of non-variola *Orthopoxvirus* DNA, including vaccinia, cowpox, monkeypox and ectromelia viruses at varying concentrations. Available information indicates that timely detection of monkeypox cases in the United States requires wide availability of diagnostic testing to control the spread of this contagious infection and there is currently a need for additional diagnostic testing for monkeypox virus in the United States.
[7] No other criteria of issuance have been prescribed by regulation under Section 564(c)(4) of the Act.

II. Scope of Authorization

I have concluded, pursuant to Section 564(d)(1) of the Act, that the scope of this authorization is limited to the indication above.

Authorized Product Details

Your product is a real-time PCR assay intended for the qualitative detection of DNA from monkeypox virus (MPXV, clade I/II) in human lesion swab specimens (i.e., swabs of acute pustular or vesicular rash) from individuals suspected of monkeypox infection by their healthcare provider. Testing is limited to laboratories certified under the Clinical Laboratory Improvement Amendments of 1988 (CLIA), 42 U.S.C. §263a, that meet the requirements to perform moderate or high complexity tests.

Results are for the identification of monkeypox virus (clade I/II) DNA which is generally detectable in human pustular or vesicular lesion specimens during the acute phase of infection. Positive results are indicative of the presence of monkeypox virus (clade I/II) DNA; clinical correlation with patient history and other diagnostic information is necessary to determine patient infection status. Positive results do not rule out bacterial infection or co-infection with other viruses. The agent detected may not be the definite cause of disease. Negative results obtained with this device do not preclude monkeypox virus (clade I/II) infection and should not be used as the sole basis for treatment or other patient management decisions. Negative results must be combined with clinical observations, patient history, and epidemiological information.

The cobas MPXV is to be used with the cobas 6800/8800 Systems, or other authorized instruments (as may be requested under Condition O. below) which is based on fully automated sample preparation (nucleic acid extraction and purification) followed by PCR amplification and detection. Automated data management is performed by the cobas 6800/8800 software. The cobas MPXV includes the materials (or other authorized materials as may be requested under Condition O. below) described in the "cobas MPXV Qualitative assay for use on the cobas 6800/8800 Systems" Instructions for Use.

Your product requires control materials (or other authorized control materials as may be requested under Condition O. below) that are described in both of the Instructions for Use. Your product also requires the use of additional authorized materials and authorized ancillary reagents that are not included with your product and are described in the Package Inserts described below.

The labeling entitled "cobas MPXV Qualitative assay for use on the cobas 6800/8800 Systems" Instructions for Use (available at https://www.fda.gov/medical-devices/emergency-use-authorizations-medical-devices/monkeypox-emergency-use-authorizations-medical-devices), the Product Information Card (PIC), and the following fact sheets pertaining to the emergency use, are required to be made available as set forth in the Conditions of Authorization (Section IV), and are collectively referred to as "authorized labeling":

- Fact Sheet for Healthcare Providers: Roche Molecular Systems, Inc. – cobas MPXV
- Fact Sheet for Patients: Roche Molecular Systems, Inc. – cobas MPXV

The above described product, when accompanied by the authorized labeling provided as set forth in the Conditions of Authorization (Section IV), is authorized to be distributed to and used by authorized laboratories under this EUA, despite the fact that it does not meet certain requirements otherwise required by applicable federal law.

I have concluded, pursuant to Section 564(d)(2) of the Act, that it is reasonable to believe that the known and potential benefits of your product, when used consistent with the Scope of Authorization of this letter (Section II), outweigh the known and potential risks of your product.

I have concluded, pursuant to Section 564(d)(3) of the Act, based on the totality of scientific evidence available to FDA, that it is reasonable to believe that your product may be effective in diagnosing infection with the monkeypox virus, when used consistent with the Scope of Authorization of this letter (Section II), pursuant to Section 564(c)(2)(A) of the Act.

FDA has reviewed the scientific information available to FDA, including the information supporting the conclusions described in Section I above, and concludes that your product (as described in the Scope of Authorization of this letter (Section II)) meets the criteria set forth in Section 564(c) of the Act concerning safety and potential effectiveness.

The emergency use of your product under this EUA must be consistent with, and may not exceed, the terms of this letter, including the Scope of Authorization (Section II) and the Conditions of Authorization (Section IV). Subject to the terms of this EUA and under the circumstances set forth in the Secretary of HHS's determination under Section 564(b)(1)(C) of the Act described above and the Secretary of HHS's corresponding declaration under Section 564(b)(1) of the Act, your product is authorized for the indication above.

III. Waiver of Certain Requirements

I am waiving the following requirements for your product during the duration of this EUA:

- Current good manufacturing practice requirements, including the quality system requirements under 21 CFR Part 820 with respect to the design, manufacture, packaging, labeling, storage, and distribution of your product, but excluding Subpart H (Acceptance Activities, 21 CFR 820.80 and 21 CFR 820.86), Subpart I (Nonconforming Product, 21 CFR 820.90), Subpart O (Statistical Techniques, 21 CFR 820.250) and Subpart M (Complaint Files, 21 CFR 820.198).

IV. Conditions of Authorization

Pursuant to Section 564(e) of the Act, I am establishing the following conditions on this authorization:

Roche Molecular Systems, Inc. (You) and Authorized Distributor(s)[8]

A. Your product must comply with the following labeling requirements pursuant to FDA regulations: the intended use statement (21 CFR 809.10(a)(2), (b)(2)); adequate directions for use (21 U.S.C. 352(f)), (21 CFR 809.10(b)(5), (7), and (8)); appropriate limitations on the use of the device including information required under 21 CFR 809.10(a)(4); and any available information regarding performance of the device, including requirements under 21 CFR 809.10(b)(12).

B. Your product must comply with the following quality system requirements pursuant to FDA regulations: 21 CFR 820 Subpart H (Acceptance Activities, 21 CFR 820.80 and 21 CFR 820.86), Subpart I (Nonconforming Product, 21 CFR 820.90), Subpart O (Statistical Techniques, 21 CFR 820.250), and Subpart M (Complaint Files, 21 CFR 820.198).

C. You and authorized distributor(s) must make your product available with the authorized labeling to authorized laboratories.

D. You and authorized distributor(s) must make available on your website(s) the authorized labeling.

E. You and authorized distributor(s) must include a physical copy of the authorized Product Information Card with each shipped product to authorized laboratories, and must make the authorized "cobas MPXV Qualitative assay for use on the cobas 6800/8800 Systems" Instructions for Use electronically available with the opportunity to request a copy in paper form, and after such request, you must promptly provide the requested information without additional cost.

F. You and authorized distributor(s) must inform authorized laboratories and relevant public health authorities of this EUA, including the terms and conditions herein, and any updates made to your product and authorized labeling.

G. Through a process of inventory control, you and authorized distributor(s) must maintain records of the authorized laboratories to which your product is distributed and the number of your product distributed.

H. You and authorized distributor(s) must collect information on the performance of your product. You must report any significant deviations from the established performance characteristics of your product of which you become aware to the Division of Microbiology (DMD)/Office of Health Technology 7 (OHT7): Office of In Vitro Diagnostics /Office of Product Evaluation and Quality (OPEQ)/Center for Devices and Radiological Health (CDRH) (via email: CDRH-EUA-Reporting@fda.hhs.gov).

I. You and authorized distributor(s) are authorized to make available additional information relating to the emergency use of your product that is consistent with, and

[8] "Authorized Distributor(s)" are identified by you, Roche Molecular Systems, Inc., in your EUA submission as an entity allowed to distribute your product.

does not exceed, the terms of this letter of authorization.

Roche Molecular Systems, Inc. (You)

J. You must register and list consistent with 21 CFR Part 807 within one month of this letter.

K. You must notify FDA of any authorized distributor(s) of your product, including the name, address, and phone number of any authorized distributor(s).

L. You must have a signed agreement with each authorized distributor that distribution of the authorized product must be consistent with this Letter of Authorization.

M. If requested by FDA, you must submit associated documents and records related to your quality system for FDA review within 48 hours of the request.

N. You must provide authorized distributor(s) with a copy of this EUA and communicate to authorized distributor(s) any subsequent amendments that might be made to this EUA and its authorized accompanying materials (e.g., Fact Sheets).

O. You may request modifications to this EUA for your product, including to the Scope of Authorization (Section II in this letter) or to the authorized labeling, including requests to make available additional authorized labeling specific to an authorized distributor. Such additional labeling may use another name for the product but otherwise must be consistent with the authorized labeling, and not exceed the terms of authorization of this letter. Any request for modification to this EUA should be submitted to DMD/OHT7/OPEQ/CDRH and require appropriate authorization from FDA.

P. You must have lot release procedures and the lot release procedures, including the study design and statistical power, must ensure that the tests released for distribution have the clinical and analytical performance claimed in the authorized labeling.

Q. If requested by FDA, you must submit lot release procedures to FDA, including sampling protocols, testing protocols, and acceptance criteria, that you use to release lots of your product for distribution in the U.S. If such lot release procedures are requested by FDA, you must provide it within 48 hours of the request.

R. You must evaluate the analytical limit of detection and assess traceability of your product with any FDA-recommended reference material(s) if requested by FDA.[9] After submission to and concurrence with the data by FDA, you must update your labeling to reflect the additional testing. Such labeling updates will be made in consultation with, and require concurrence of, DMD/OHT7/OPEQ/CDRH.

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[9] Traceability refers to tracing analytical sensitivity/reactivity back to an FDA-recommended reference material. FDA may request, for example, that you perform this study in the event that we receive reports of adverse events concerning your product.

S. You must have a process in place to track adverse and report to FDA pursuant to 21 CFR Part 803.

T. You must evaluate the impact of monkeypox viral mutations on your product's performance. Such evaluations must occur on an ongoing basis and must include any additional data analysis that is requested by FDA in response to any performance concerns you or FDA identify during routine evaluation. Additionally, if requested by FDA, you must submit records of these evaluations for FDA review within 48 hours of the request. If your evaluation identifies viral mutations that affect the stated expected performance of your device, you must notify FDA immediately (via email: CDRH-EUA-Reporting@fda.hhs.gov).

U. If requested by FDA, you must update your labeling within 7 calendar days to include any additional labeling risk mitigations identified by FDA regarding the impact of viral mutations on test performance. Such updates will be made in consultation with, and require concurrence of, DMD/OHT7/OPEQ/CDRH.

V. You must submit to DMD/OHT7/OPEQ/CDRH within 3 months of the date of this letter your plan and anticipated timeline to establish and maintain a quality system that is appropriate for your product's design and manufacture, and that meets the requirements of either the 2016 edition of ISO 13485 or 21 CFR Part 820.

Authorized Laboratories

W. Authorized laboratories that receive your product must notify the relevant public health authorities of their intent to run your product prior to initiating testing.

X. Authorized laboratories using your product must have a process in place for reporting test results to healthcare providers and relevant public health authorities, as appropriate.

Y. Authorized laboratories using your product must include with test result reports, all authorized Fact Sheets. Under exigent circumstances, other appropriate methods for disseminating these Fact Sheets may be used, which may include mass media.

Z. Authorized laboratories using your product must use your product as outlined in the authorized labeling. Deviations from the authorized procedures, including the authorized instruments, authorized extraction methods, authorized clinical specimen types, authorized control materials, authorized other ancillary reagents and authorized materials required to use your product are not permitted.

AA. Authorized laboratories must have a process in place to track adverse events and report to you (via Roche Diagnostics US Customer Technical Support 1-800-526-1247) and to FDA pursuant to 21 CFR Part 803.

BB. All laboratory personnel using your product must be appropriately trained in real-time PCR techniques and use appropriate laboratory and personal protective equipment when handling your product and use your product in accordance with the authorized labeling.

Page 8 – Michael Lynch, Roche Molecular Systems, Inc.

Roche Molecular Systems, Inc. (You), Authorized Distributor(s) and Authorized Laboratories

CC. You, authorized distributor(s), and authorized laboratories must collect information on the performance of your product and must report any significant deviations from the established performance characteristics of your product of which they become aware to DMD/OHT7/OPEQ/CDRH (via email: CDRH-EUA-Reporting@fda.hhs.gov) In addition, authorized distributor(s) and authorized laboratories report to you (via Roche Diagnostics US Customer Technical Support 1-800-526-1247).

DD. You, authorized distributor(s), and authorized laboratories using your product must ensure that any records associated with this EUA, are maintained until otherwise notified by FDA. Such records must be made available to FDA for inspection upon request.

Conditions Related to Printed Materials, Advertising and Promotion

EE. All descriptive printed matter, advertising and promotional materials relating to the use of your product shall be consistent with the authorized labeling, as well as the terms set forth in this EUA and meet the requirements set forth in section 502(a), (q)(1), and (r) of the Act, as applicable, and FDA implementing regulations.

FF. No descriptive printed matter, advertising or promotional materials relating to the use of your product may represent or suggest that this test is safe or effective for the detection of monkeypox virus or other non-variola orthopoxviruses.

GG. All descriptive printed matter, advertising and promotional materials relating to the use of your product shall clearly and conspicuously state that:

- This product has not been FDA cleared or approved, but has been authorized for emergency use by FDA under an EUA for use by the authorized laboratories;
- This product has been authorized only for the detection of nucleic acid from monkeypox virus, not for any other viruses or pathogens; and
- The emergency use of this product is only authorized for the duration of the declaration that circumstances exist justifying the authorization of emergency use of in vitro diagnostics for detection and/or diagnosis of infection with the monkeypox virus, including in vitro diagnostics that detect and/or diagnose infection with non-variola *Orthopoxvirus*, under Section 564(b)(1) of the Federal Food, Drug, and Cosmetic Act, 21 U.S.C. § 360bbb-3(b)(1), unless the declaration is terminated or authorization is revoked sooner.

The emergency use of your product as described in this letter of authorization must comply with the conditions and all other terms of this authorization.

Page 9 – Michael Lynch, Roche Molecular Systems, Inc.

V. Duration of Authorization

This EUA will be effective until the declaration that circumstances exist justifying the authorization of the emergency use of in vitro diagnostics for detection and/or diagnosis of infection with the monkeypox virus, including in vitro diagnostics that detect and/or diagnose infection with non-variola *Orthopoxvirus*, is terminated under Section 564(b)(2) of the Act or the EUA is revoked under Section 564(g) of the Act.

Sincerely,

/s/

Namandjé N. Bumpus, Ph.D.
Chief Scientist
Food and Drug Administration

Enclosure

Dated: December 27, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–28460 Filed 12–29–22; 8:45 am]

BILLING CODE 4164–01–C

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Acute Radiation Syndrome Medical Countermeasures—Amendment

ACTION: Declaration amendment.

SUMMARY: The Secretary is amending the Declaration issued in the **Federal Register** of October 10, 2008, and as amended and republished January 1, 2016, pursuant to the Public Health Service Act, to extend the effective time period of the Republished Declaration, as amended.

DATES: This amendment of the January 1, 2016, Republished Declaration is effective January 1, 2023.

FOR FURTHER INFORMATION CONTACT: L. Paige Ezernack, Administration for Strategic Preparedness and Response, Department of Health and Human Services, 200 Independence Avenue SW, Washington, DC 20201; 202–260–0365, *paige.ezernack@hhs.gov.*

SUPPLEMENTARY INFORMATION: The Public Readiness and Emergency Preparedness Act (PREP Act) authorizes the Secretary of Health and Human Services (the Secretary) to issue a Declaration to provide liability immunity to certain individuals and entities (Covered Persons) against any claim of loss caused by, arising out of, relating to, or resulting from the administration or use of medical countermeasures (Covered Countermeasures), except for claims that meet the PREP Act's definition of willful misconduct. The Secretary may, through publication in the **Federal Register**, amend any portion of a Declaration.

The PREP Act was enacted on December 30, 2005, as Public Law 109–148, division C, section 2. It amended the Public Health Service (PHS) Act, adding section 319F–3, which addresses liability immunity, and section 319F–4, which creates a compensation program. These sections are codified in the U.S. Code as 42 U.S.C. 247d–6d and 42 U.S.C. 247d–6e, respectively. Section 319F–3 of the PHS Act has been amended by the Pandemic and All-Hazards Preparedness Reauthorization Act (PAHPRA), Public Law 113–5, enacted on March 13, 2013, and the Coronavirus Aid, Relief, and Economic Security (CARES) Act, Public Law 116–136, enacted on March 27, 2020, to expand Covered Countermeasures under the PREP Act.

The Secretary is now amending the Republished Declaration to extend the time period for which liability immunity is in effect for all of the Covered Countermeasures to December 31, 2027.

Renewal of the PREP Act declaration for acute radiation exposure is requested due to the continued national security threat posed. A nuclear attack or other exposure to ionizing radiation would present the United States with major challenges in our ability to protect the public. PREP Act coverage of countermeasures is critical to the engagement with potential product sponsors to include those countermeasures that would be used in a response, such as blood products. Extension of the PREP Act declaration including covered countermeasures for acute radiation exposure will be critical to United States' preparedness for events involving ionizing radiation.

Unless otherwise noted, all statutory citations below are to the U.S. Code.

Republished Declaration

Declaration, as Amended, for Public Readiness and Emergency Preparedness Act Coverage for Acute Radiation Syndrome Medical Countermeasures

This Declaration amends the January 1, 2016, Republished Declaration under the PREP Act. To the extent any term of the prior Declaration is inconsistent with any provision of this Republished Declaration, the terms of this Republished Declaration are controlling.

I. Determination of Public Health Emergency or Credible Risk of Future Public Health Emergency

42 U.S.C. 247d–6d(b)(1)

I have determined that there is a credible risk that an unintentional radioactive release, a deliberate detonation of a nuclear device, or other radiological or nuclear incident that could result in population exposures to radiation and resulting acute radiation syndrome and/or delayed effects of acute radiation exposure may in the future constitute a public health emergency.

II. Factors Considered

42 U.S.C. 247d–6d(b)(6)

I have considered the desirability of encouraging the design, development, clinical testing, or investigation, manufacture, labeling, distribution, formulation, packaging, marketing, promotion, sale, purchase, donation, dispensing, prescribing, administration, licensing, and use of the Covered Countermeasures.

III. Recommended Activities

42 U.S.C. 247d–6d(b)(1)

I recommend, under the conditions stated in this Declaration, the manufacture, testing, development, distribution, administration, or use of the Covered Countermeasures.

IV. Liability Immunity

42 U.S.C. 247d–6d(a), 247d–6d(b)(1)

Liability immunity as prescribed in the PREP Act and conditions stated in this Declaration is in effect for the Recommended Activities described in section III.

V. Covered Persons

42 U.S.C. 247d–6d(i)(2), (3), (4), (6), (8)(A) and (B)

Covered Persons who are afforded liability immunity under this Declaration are manufacturers, distributors, program planners, ''qualified persons,'' and their officials, agents, and employees, as those terms are defined in the PREP Act, and the United States.

In addition, I have determined that the following additional persons are qualified persons: (a) Any person authorized in accordance with the public health and medical emergency response of the Authority Having Jurisdiction, as described in section VII below, to prescribe, administer, deliver, distribute or dispense the Covered Countermeasures, and their officials, agents, employees, contractors and volunteers, following a declaration of an emergency; (b) Any person authorized to prescribe, administer, or dispense the Covered Countermeasures or who is otherwise authorized to perform an activity under an Emergency Use Authorization (EUA) in accordance with section 564 of the Federal Food, Drug, and Cosmetic (FD&C) Act, and; (c) Any person authorized to prescribe, administer, or dispense Covered Countermeasures in accordance with section 564A of the FD&C Act.

VI. Covered Countermeasures

42 U.S.C. 247d–6b(c)(1)(B), 42 U.S.C. 247d–6d(i)(1) and (7)

Covered Countermeasures are any antimicrobial (antibiotic, antifungal, antiviral); any other drug; any biologic; or any diagnostic or other device administered to identify, prevent or treat acute radiation syndrome and its associated clinical manifestations, or delayed effects of acute radiation exposure or adverse events from such countermeasures.

Covered Countermeasures must be ''qualified pandemic or epidemic products,'' or ''security countermeasures,'' or drugs, biological products, or devices authorized for investigational or emergency use, as those terms are defined in the PREP Act, the FD&C Act, and the PHS Act.

VII. Limitations on Distribution

42 U.S.C. 247d–6d(a)(5) and (b)(2)(E)

I have determined that liability immunity is afforded to Covered Persons only for Recommended Activities involving Covered Countermeasures that are related to:

(a) Present or future Federal contracts, cooperative agreements, grants, other transactions, interagency agreements, memoranda of understanding, or other Federal agreements, or activities directly conducted by the Federal Government.

or

(b) Activities authorized in accordance with the public health and medical response of the Authority Having Jurisdiction to prescribe, administer, deliver, distribute or dispense the Covered Countermeasures following a declaration of an emergency.

i. The Authority Having Jurisdiction means the public agency or its delegate that has legal responsibility and authority for responding to an incident, based on political or geographical (*e.g.,* city, county, tribal, state, or Federal boundary lines) or functional (*e.g.,* law enforcement, public health) range or sphere of authority.

ii. A declaration of emergency means any declaration by any authorized local, regional, state, or Federal official of an emergency specific to events that indicate an immediate need to administer and use the Covered Countermeasures, with the exception of a Federal Declaration in support of an EUA under section 564 of the FD&C Act unless such Declaration specifies otherwise.

I have also determined that for governmental program planners only, liability immunity is afforded only to the extent such program planners obtain Covered Countermeasures through voluntary means, such as (1) donation; (2) commercial sale; (3) deployment of Covered Countermeasures from federal stockpiles; or (4) deployment of donated, purchased, or otherwise voluntarily obtained Covered Countermeasures from state, local, or private stockpiles.

VIII. Category of Disease, Health Condition, or Threat

42 U.S.C. 247d–6d(b)(2)(A)

The category of disease, health condition, or threat for which I recommend the administration or use of the Covered Countermeasures is acute radiation syndrome or delayed effects of acute radiation exposure resulting from an unintentional radioactive release, a deliberate detonation of a nuclear device, or other radiological or nuclear incident.

IX. Administration of Covered Countermeasures

42 U.S.C. 247d–6d(a)(2)(B)

Administration of the Covered Countermeasure means physical provision of the countermeasures to recipients, or activities and decisions directly relating to public and private delivery, distribution and dispensing of the countermeasures to recipients, management and operation of countermeasure programs, or management and operation of locations for purpose of distributing and dispensing countermeasures.

X. Population

42 U.S.C. 247d–6d(a)(4), 247d–6d(b)(2)(C)

The populations of individuals include any individual who uses or is administered the Covered Countermeasures in accordance with this Declaration.

Liability immunity is afforded to manufacturers and distributors without regard to whether the countermeasure is used by or administered to this population; liability immunity is afforded to program planners and qualified persons when the countermeasure is used by or administered to this population, or the program planner or qualified person reasonably could have believed the recipient was in this population.

XI. Geographic Area

42 U.S.C. 247d–6d(a)(4), 247d–6d(b)(2)(D)

Liability immunity is afforded for the administration or use of a Covered

Countermeasure without geographic limitation.

Liability immunity is afforded to manufacturers and distributors without regard to whether the countermeasure is used by or administered in these geographic areas; liability immunity is afforded to program planners and qualified persons when the countermeasure is used by or administered in these geographic areas, or the program planner or qualified person reasonably could have believed the recipient was in these geographic areas.

XII. Effective Time Period

42 U.S.C. 247d–6d(b)(2)(B)

Liability immunity for Covered Countermeasures obtained through means of distribution other than in accordance with the public health and medical response of the Authority Having Jurisdiction extends through December 31, 2027.

Liability immunity for Covered Countermeasures administered and used in accordance with the public health and medical response of the Authority Having Jurisdiction begins with a Declaration and lasts through (1) the final day the emergency Declaration is in effect or (2) December 31, 2027, whichever occurs first.

XIII. Additional Time Period of Coverage

42 U.S.C. 247d–6d(b)(3)(B) and (C)

I have determined that an additional twelve (12) months of liability protection is reasonable to allow for the manufacturer(s) to arrange for disposition of the Covered Countermeasure, including return of the Covered Countermeasures to the manufacturer, and for Covered Persons to take other appropriate actions to limit the administration or use of the Covered Countermeasures.

Covered Countermeasures obtained for the Strategic National Stockpile (SNS) during the effective period of this Declaration for Covered Countermeasures obtained through means of distribution other than in accordance with the public health and medical response of the Authority Having Jurisdiction are covered through the date of administration or use pursuant to a distribution or release from the SNS.

XIV. Countermeasures Injury Compensation Program

42 U.S.C. 247d–6e

The PREP Act authorizes the Countermeasures Injury Compensation Program (CICP) to provide benefits to certain individuals or estates of individuals who sustain a serious physical covered injury as the direct result of the administration or use of the Covered Countermeasures and/or benefits to certain survivors of individuals who die as a direct result of the administration or use of the Covered Countermeasures. The causal connection between the countermeasure and the serious physical injury must be supported by compelling, reliable, valid, medical, and scientific evidence in order for the individual to be considered for compensation. The CICP is administered by the Health Resources and Services Administration, within the Department of Health and Human Services. Information about the CICP is available at the toll-free number 1–855–266–2427 or *http://www.hrsa.gov/cicp/*.

XV. Amendments

42 U.S.C. 247d–6d(b)(4)

The October 10, 2008, Declaration Under the PREP Act for Acute Radiation Syndrome Medical Countermeasures was first published on October 17, 2008, and amended and republished on January 1, 2016. This is the second amendment to the Declaration.

Further amendments to this Declaration will be published in the **Federal Register**.

Authority: 42 U.S.C. 247d–6d.

Xavier Becerra,

Secretary of Health and Human Services.

[FR Doc. 2022–28437 Filed 12–29–22; 8:45 am]

BILLING CODE 4150–37–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; Workshops on Computational and Analytical Research Methods.

Date: January 30, 2023.

Time: 1:00 p.m. to 1:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Drug Abuse, 301 North Stonestreet Avenue, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Caitlin Elizabeth Angela Moyer, Ph.D., Scientific Review Officer, Scientific Review Branch, National Institute on Drug Abuse, NIH, 301 North Stonestreet Avenue, MSC 6021, Bethesda, MD 20892, (301) 443–4577, *caitlin.moyer@nih.gov*.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; HEAL Initiative: Translating Research to Practice to end the Overdose Crisis.

Date: February 10, 2023.

Time: 11:00 a.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Drug Abuse, 301 North Stonestreet Avenue, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Soyoun Cho, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, National Institute on Drug Abuse, NIH, 301 North Stonestreet Avenue, MSC 6021, Bethesda, MD 20892, (301) 594–9460, *Soyoun.cho@nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.277, Drug Abuse Scientist Development Award for Clinicians, Scientist Development Awards, and Research Scientist Awards; 93.278, Drug Abuse National Research Service Awards for Research Training; 93.279, Drug Abuse and Addiction Research Programs, National Institutes of Health, HHS)

Dated: December 27, 2022.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–28449 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Mental Health; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), title 5 U.S.C., as amended. The contract proposals and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Mental Health Special Emphasis Panel; RFP Review: National NeuroHIV Tissue Consortium (NNTC) Clinical Sites and Data Coordination Centers.

Date: January 24, 2023.

Time: 12:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852 (Virtual Meeting).

Contact Person: Nicholas Gaiano, Ph.D., Review Branch Chief, Division of Extramural Activities, National Institute of Mental Health, National Institutes of Health, Neuroscience Center/Room 6150/MSC 9606, 6001 Executive Boulevard, Bethesda, MD 20892–9606, 301–443–2742, *nick.gaiano@nih.gov.*

(Catalogue of Federal Domestic Assistance Program No. 93.242, Mental Health Research Grants, National Institutes of Health, HHS)

Dated: December 27, 2022.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–28446 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Mental Health; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Mental Health Initial Review Group; Effectiveness of Mental Health Interventions Study Section.

Date: February 3, 2023.

Time: 9:30 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852 (Virtual Meeting).

Contact Person: Marcy Ellen Burstein, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, National Institutes of Health, Neuroscience Center, 6001 Executive Blvd., Room 6143, MSC 9606, Bethesda, MD 20892–9606, 301–443–9699, *bursteinme@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program No. 93.242, Mental Health Research Grants, National Institutes of Health, HHS)

Dated: December 27, 2022.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–28445 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Human Genome Research Institute; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the National Advisory Council for Human Genome Research.

The meeting will be open to the public as indicated below. Individuals who need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting. The meeting will be videocast and can be accessed from *https://www.genome.gov/about-nhgri/Institute-Advisors/National-Advisory-Council-for-Human-Genome-Research*.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Advisory Council for Human Genome Research.

Date: February 13–14, 2023.

Closed: February 13, 2023, 10:00 a.m. to 11:00 a.m.

Agenda: To review and evaluate grant applications.

Place: National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Suite 1100, Bethesda, MD 20892 (Virtual Meeting).

Open: February 13, 2023, 11:30 a.m. to 6:00 p.m.

Agenda: Report of Institute Director and Institute Staff.

Place: National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Suite 1100, Bethesda, MD 20817 (Virtual Meeting).

Closed: February 14, 2023, 10:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Suite 1100, Bethesda, MD 20817 (Virtual Meeting).

Contact Person: Rudy O. Pozzatti, Ph.D., Scientific Review Officer, Scientific Review Branch, National Human Genome Research Institute, 6700 Rockledge Drive, Suite 1100, Rockville, MD 20852, (301) 402–0838, *pozzattr@mail.nih.gov*.

Any interested person may file written comments with the committee within 15 days after the meeting by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

Information is also available on the Institute's/Center's home page: *http://www.genome.gov/council,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.172, Human Genome Research, National Institutes of Health, HHS)

Dated: December 27, 2022.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–28447 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Dental and Craniofacial Research; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the National Advisory Dental and Craniofacial Research Council.

The meeting will be held as a virtual meeting and is open to the public. Individuals who plan to view the virtual meeting and need special assistance or other reasonable accommodations to view the meeting, should notify the Contact Person listed below in advance of the meeting. The open session will be videocast and can be accessed from the NIH Videocasting and Podcasting website (*http://videocast.nih.gov/*).

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Advisory Dental and Craniofacial Research Council.

Date: January 25, 2023.

Open: 10:00 a.m. to 2:00 p.m.

Agenda: Report of the Director, NIDCR and concept clearances.

Place: National Institute of Dental and Craniofacial Research, 6701 Democracy Boulevard, Bethesda, MD 20892 (Virtual Meeting).

Closed: 2:00 p.m. to 3:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Dental and Craniofacial Research, 6701 Democracy Boulevard, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Lynn M. King, Ph.D., Executive Secretary, Division of Extramural Activities, National Institute of Dental and Craniofacial Research, 6701 Democracy Blvd., Room 960, Bethesda, MD 20892–4878, (301) 594–5006, *Lynn.King@nih.gov.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

Information is also available on the Institute's/Center's home page: *http://www.nidcr.nih.gov/about,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program No. 93.121, Oral Diseases and Disorders Research, National Institutes of Health, HHS)

Dated: December 27, 2022.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–28448 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Prospective Grant of an Exclusive Patent License: Development and Commercialization of Natural Killer Cell Therapies for Cancer

AGENCY: National Institutes of Health, HHS.

ACTION: Notice.

SUMMARY: The National Cancer Institute, an institute of the National Institutes of Health, Department of Health and Human Services, is contemplating the grant of an Exclusive Patent License to practice the inventions embodied in the Patents and Patent Applications listed in the **SUPPLEMENTARY INFORMATION** section of this notice to Replay Holdings LLC (''Replay'') located in San Diego, California.

DATES: Only written comments and/or applications for a license which are received by the National Cancer Institute's Technology Transfer Center on or before January 17, 2023 will be considered.

ADDRESSES: Requests for copies of the patent application, inquiries, and comments relating to the contemplated an Exclusive Patent License should be directed to: Suna Gulay French, Technology Transfer Manager, Telephone: (240) 276–7424; Email: *suna.gulay@nih.gov.*

SUPPLEMENTARY INFORMATION:

Intellectual Property

Group A

1. United States Provisional Patent Application No. 62/084,654 filed November 26, 2014, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–0–US–01];
2. PCT Patent Application No. PCT/US2015/062269 filed November 24, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–PCT–01];
3. Australian Patent No. 2015353720 issued June 11, 2020, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–AU–02];
4. Canadian Patent Application No. 2,968,399 effective filing date of November 24, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–CA–03];
5. Chinese Patent No. ZL201580070673.7 issued November 16, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–CN–04];
6. European Patent No. 3223850 issued January 8, 2020, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–EP–05];
   a. Validated in the following jurisdictions: AT, BE, CH, CZ, DE, ES, FR, GB, GR, IE, IT, NL, NO, PL, PT, SE, SI, SK, TR;
7. Israeli Patent No. 252258 issued March 2, 2022, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–IL–06];
8. Japanese Patent No. 6863893 issued April 5, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–JP–07];
9. Korean Patent Application No. 2017–7017289 effective filing date of November 24, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–KR–08];
10. Mexican Patent No. 384919 issued July 29, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–MX–09];
11. New Zealand Patent Application No. 732045 effective filing date of November 24, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–NZ–10];
12. Saudi Arabian Patent No. 7697 issued March 11, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–SA–11];
13. Singapore Patent Application No. 11201704155U effective filing date of November 24, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–SG–12];
14. United States Patent No. 11,207,394 issued December 28, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–US–13];
15. Hong Kong Patent No. 1243642 issued January 22, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–HK–14];
16. European Patent Application No. 20150279.6 filed January 3, 2020, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–EP–15];
17. Singapore Patent Application No. 10201913978R filed December 31, 2019, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–SG–16];
18. Australian Patent Application No. 2020203465 filed May 26, 2020, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–AU–36];
19. Saudi Arabian Patent Application No. 520420365 filed October 15, 2020, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–SA–37];
20. Hong Kong Patent Application No. 42020021375.9 effective filing date of November 24, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–HK–38];
21. Japanese Patent Application No. 2021–063092 filed April 1, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–JP–40];
22. Chinese Patent Application No. 202111263859.8 filed October 27, 2021, entitled ''Anti-Mutated KRAS T Cell

Receptors'' [HHS Reference No. E–028–2015–1–CN–41];

23. United States Patent Application No. 17/535,318 filed November 24, 2021, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–US–42];

24. Hong Kong Patent Application No. 42022054674.1 filed June 27, 2022, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–028–2015–1–HK–43];

25. United States Provisional Patent Application No. 62/171,321 filed June 5, 2015, entitled ''Anti-Mutated KRAS T Cell Receptors'' [HHS Reference No. E–180–2015–0–US–01];

26. United States Provisional Patent Application No. 62/218,688 filed September 15, 2015, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–US–01];

27. PCT Patent Application No. PCT/US2016/050875 filed September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–PCT–02];

28. Australian Patent No. 2016323017 issued February 25, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–AU–03];

29. Canadian Patent Application No. 2,998,869 effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–CA–04];

30. Chinese Patent No. ZL201680058891.3 issued October 8, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–CN–05];

31. European Patent No. 3350213 issued March 31, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–EP–06];

a. Validated in the following jurisdictions: BE, CH, DE, DK, ES, FR, GB, IE, IT, NL, NO and SE.

32. Israeli Patent Application No. 257840 effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–IL–07];

33. Japanese Patent Application No. 2018–513423 effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–JP–08];

34. Korean Patent Application No. 2018–7010326, effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–KR–09];

35. Mexican Patent Application No. MX/a/2018/003062 effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–MX–10];

36. New Zealand Patent Application No. 740714 effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–NZ–11];

37. Saudi Arabian Patent Application No. 518391109 effective filing date of September 9, 2016, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–SA–12];

38. Singapore Patent No. 11201802069U issued March 31, 2022, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–SG–13];

39. United States Patent No. 10,556,940 issued February 11, 2020, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–US–14];

40. Hong Kong Patent No. HK1257902 issued December 24, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–HK–15];

41. United States Patent Application No. 16/739,310 filed January 10, 2020, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–US–16];

42. Singapore Patent Application No. 10201913868X filed December 30, 2019, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–SG–17];

43. Australian Patent No. 2021200833 issued August 18, 2022, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–AU–18];

44. European Patent Application No. 21162567.8 filed March 15, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–EP–19];

45. Saudi Arabian Patent Application No. 521421309 filed February 23, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–SA–20];

46. Chinese Patent Application No. 202111083392.9 filed September 15, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–CN–33];

47. New Zealand Patent Application No. 779633 filed September 2, 2021, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–NZ–34];

48. Australian Patent Application No. 2022209229 filed July 26, 2022, entitled ''T Cell Receptors Recognizing HLA–CW8 Restricted Mutated KRAS'' [HHS Reference No. E–265–2015–0–AU–35];

49. United States Provisional Patent Application No. 62/369,883 filed August 2, 2016, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–US–01];

50. PCT Patent Application No. PCT/US2017/044615 filed July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–PCT–02];

51. Australian Patent Application No. 2017306038 effective filing date of July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–AU–03];

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53. Chinese Patent Application No. 201780059356.4 effective filing date of July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–CN–05];

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56. United States Patent No. 10,611,816 issued April 7, 2020, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–US–08];

57. Israeli Patent Application No. 264425 effective filing date of July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–IL–09];

58. Korean Patent Application No. 2019–7005837 effective filing date of July 31, 2017, entitled ''Anti-KRAS

G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–KR–10];

59. Singapore Patent Application No. 11201900654Q effective filing date of July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–SG–11];

60. Hong Kong Patent Application No. 19133082.8 effective filing date of July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–HK–12];

61. Hong Kong Patent Application No. 19132196.7 effective filing date of July 31, 2017, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–HK–13];

62. Singapore Patent Application No. 10201913959W filed December 31, 2019, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–SG–14];

63. United States Patent No. 11,208,456 issued December 28, 2021, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–US–15];

64. United States Patent Application No. 17/345,390 filed June 11, 2021, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–US–16];

65. United States Patent Application No. 17/541,619 filed December 3, 2021, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–US–17];

66. Japanese Patent Application No. 2021–199878 filed December 9, 2021, entitled ''Anti-KRAS G12D T Cell Receptors'' [HHS Reference No. E–175–2016–0–JP–18];

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68. United States Provisional Patent Application No. 62/560,930 filed September 20, 2017, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–US–01];

69. PCT Patent Application No. PCT/US2018/051641 filed September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–PCT–02];

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71. Taiwanese Patent Application No. 107133221 filed September 20, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–TW–05];

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74. Brazilian Patent Application No. BR112020005469–0 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–BR–08];

75. Canadian Patent Application No. 3,076,339 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–CA–09];

76. Chinese Patent Application No. 201880060535.4 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–CN–10];

77. Costa Rican Patent Application No. 2020–0150 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–CR–11];

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79. European Patent Application No. 18792591.2 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–EP–13];

80. Israeli Patent Application No. 273254 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–IL–14];

81. Indian Patent Application No. 202047011647 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–IN–15];

82. Japanese Patent Application No. 2020–516422 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–JP–16];

83. Korean Patent Application No. 2020–7011112 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–KR–17];

84. Mexican Patent Application No. MX/a/2020/003117 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–MX–18];

85. New Zealand Patent Application No. 762831 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–NZ–19];

86. Singapore Patent Application No. 11202002425P effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–SG–20];

87. Hong Kong Patent Application No. 62020019700.7 effective filing date of September 19, 2018, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–HK–21];

88. Brazilian Patent Application No. BR122021018418–6 filed September 16, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–BR–22];

89. United States Patent Application No. 17/692,787 filed March 11, 2022, entitled ''HLA Class II-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–181–2017–0–US–23];

90. United States Provisional Patent Application No. 62/594,244 filed December 4, 2017, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–US–01];

91. PCT Patent Application No. PCT/US2018/063581 filed December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–PCT–02];

92. Australian Patent Application No. 2018378200 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–AU–03];

93. Brazilian Patent Application No. BR112020011111–2 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–BR–04];

94. Canadian Application No. 3,084,246 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–CA–05];

95. Chinese Application No. 201880087270.7 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–CN–06];

96. Costa Rican Application No. 2020–0287 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–CR–07];

97. Eurasian Application No. 202091335 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–EA–08];

98. European Application No. 18830062.8 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–EP–09];

99. Israeli Application No. 275031 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–IL–10];

100. Indian Application No. 202047026991 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–IN–11];

101. Japanese Application No. 2020–530325 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–JP–12];

102. Korean Application No. 2020–7019185 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–KR–13];

103. Mexican Application No. MX/a/2020/005765 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–MX–14];

104. New Zealand Application No. 765440 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–NZ–15];

105. Singapore Application No. 11202005236Q effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–SG–16];

106. United States Patent Application No. 16/769,144 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–US–17];

107. Hong Kong Patent Application No. 62021026617.2 effective filing date of December 3, 2018, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–HK–18];

108. Brazilian Patent Application No. BR122021024382–4 filed December 2, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–BR–19];

109. United States Patent Application No. 17/931,391 filed September 12, 2022, entitled ''HLA Class I-Restricted T Cell Receptors Against Mutated RAS'' [HHS Reference No. E–239–2017–0–US–20];

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111. Taiwanese Patent Application No. 109102511 filed January 22, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–TW–02];

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113. Australian Patent Application No. 2020211922 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–AU–04];

114. Canadian Patent Application No. 3,127,096 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–CA–05];

115. Chinese Patent Application No. 202080010373.0 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–CN–06];

116. European Patent Application No. 20705599.7 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–EP–07];

117. Japanese Patent Application No. 2021–542206 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–JP–08];

118. Korean Patent Application No. 2021–7026169 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–KR–09];

119. United States Patent Application No. 17/424,591 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–US–10];

120. Hong Kong Patent Application No. 62022048432.8 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–HK–11];

121. Hong Kong Patent Application No. 62022047561.5 effective filing date of January 21, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12R Mutation'' [HHS Reference No. E–029–2019–0–HK–12];

122. United States Provisional Patent Application No. 62/975,544 filed February 12, 2020, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–US–01];

123. PCT Patent Application No. PCT/US2021/017794 filed February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–PCT–02];

124. Taiwanese Patent Application No. 110105194 filed February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–TW–03];

125. Australian Patent Application No. 2021221138 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–AU–04];

126. Canadian Patent Application No. 3,168,015 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–CA–05];

127. Chinese Patent Application No. 202180014038.2 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–CN–06];

128. European Patent Application No. 21710730.9 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–EP–07];

129. Indian Patent Application No. 202247050250 effective filing date of February 12, 2021, entitled ''HLA Class

I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–IN–08];

130. Japanese Patent Application No. 2022–548811 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–JP–09];

131. Korean Patent Application No. 2022–7031175 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–KR–10];

132. Singapore Patent Application No. 11202251837Y effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–SG–11];

133. United Kingdom Patent Application No. 2211733.7 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–GB–12];

134. United States Patent Application No. 17/799,163 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–US–13];

135. Brazilian Patent Application No. BR112022015888–2 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–BR–14];

136. Chilean Patent Application No. 02208–2022 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–CL–15];

137. Colombian Patent Application No. NC2022/0012922 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–CO–16];

138. Israeli Patent Application No. 295252 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–IL–18];

139. Mexican Patent Application No. MX/a/2022/009654 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–MX–19];

140. New Zealand Patent Application No. 790950 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–NZ–20];

141. South African Patent Application No. 2022/08853 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–ZA–21];

142. Cuban Patent Application No. 2022–0044 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–CU–22];

143. Russian Patent Application No. 2022124004 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–031–2020–0–RU–23];

144. United States Provisional Patent Application No. 62/976,655 filed February 14, 2020, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–0–US–01];

145. United States Provisional Patent Application No. 63/060,340 filed August 3, 2020, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–190–2020–0–US–01];

146. PCT Patent Application No. PCT/US2021/017852 filed February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–PCT–01];

147. Taiwanese Patent Application No. 110105193 filed February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–TW–02];

148. Australian Patent Application No. 2021220957 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–AU–03];

149. Canadian Patent Application No. 3,167,382 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–CA–04];

150. Chinese Patent Application No. 202180014281.4 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–CN–05];

151. European Patent Application No. 21710740.8 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–EP–06];

152. Indian Patent Application No. 202247050807 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–IN–07];

153. Japanese Patent Application No. 2022–549088 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–JP–08];

154. Korean Patent Application No. 2022–7031589 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–KR–09];

155. Singapore Patent Application No. 11202251947C effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–SG–10];

156. United Kingdom Patent Application No. 2211757.6 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–GB–11];

157. United States Patent Application No. 17/799,193 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–US–12];

158. Brazilian Patent Application No. BR112022015897–1 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–BR–13];

159. Mexican Patent Application No. MX/a/2022/009825 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–MX–14];

160. New Zealand Patent Application No. 791024 effective filing date of February 12, 2021, entitled ''HLA Class I-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–074–2020–1–NZ–15];

161. United States Provisional Patent Application No. 62/981,856 filed February 26, 2020, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–US–01];

162. PCT Patent Application No. PCT/US2021/019775 filed February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–PCT–02];

163. Taiwanese Patent Application No. 110106886 filed February 26, 2021,

entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–TW–03];

164. Australian Patent Application No. 2021225872 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–AU–04];

165. Canadian Patent Application No. 3,169,086 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–CA–05];

166. Chinese Patent Application No. 202180016761.4 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–CN–06];

167. European Patent Application No. 21712694.5 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–EP–07];

168. Indian Patent Application No. 202247052620 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–IN–08];

169. Korean Patent Application No. 2022–7033222 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–KR–10];

170. Singapore Patent Application No. 1120225235K effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–SG–11];

171. United Kingdom Patent Application No. 2212195.8 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–GB–12];

172. United States Patent Application No. 17/802,464 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–US–13];

173. Brazilian Patent Application No. BR112022016661–3 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–BR–14];

174. Mexico Patent Application No. MX/a/2022/010157 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–MX–15];

175. New Zealand Patent Application No. 791348 effective filing date of February 26, 2021, entitled ''HLA Class II-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–088–2020–0–NZ–16];

176. United States Provisional Patent Application No. 63/050,931 filed July 13, 2020, entitled ''HLA Class II-Restricted DRB T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–165–2020–0–US–01];

177. PCT Patent Application No. PCT/US2021/041375 filed July 13, 2021, entitled ''HLA Class II-Restricted DRB T Cell Receptors Against RAS with G12D Mutation'' [HHS Ref. No. E–165–2020–0–PCT–02];

178. United States Provisional Patent Application No. 63/052,502 filed July 16, 2020, entitled ''HLA Class II-Restricted DRB1*01:01 T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–172–2020–0–US–01];

179. PCT Patent Application No. PCT/US2021/041737 filed July 15, 2021, entitled ''HLA Class II-Restricted DRB1*01:01 T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–172–2020–0–PCT–02];

180. United States Provisional Patent Application No. 63/086,674 filed October 2, 2020, entitled ''HLA Class II-Restricted DQ T Cell Receptors Against RAS with G13D Mutation'' [HHS Ref. No. E–189–2020–0–US–01];

181. PCT Patent Application No. PCT/US2021/053060 filed October 1, 2021, entitled ''HLA Class II-Restricted DQ T Cell Receptors Against RAS with G13D Mutation'' [HHS Ref. No. E–189–2020–1–PCT–01];

182. Taiwanese Patent Application No. 110136658 filed October 1, 2021, entitled ''HLA Class II-Restricted DQ T Cell Receptors Against RAS with G13D Mutation'' [HHS Ref. No. E–189–2020–1–TW–02]; and

183. United States Provisional Patent Application No. 63/284,884 filed December 1, 2021, entitled ''HLA–A3-Restricted T Cell Receptors Against RAS with G12V Mutation'' [HHS Ref. No. E–219–2021–0–US–01].

Group B

1. United States Provisional Patent Application No. 62/565,383 filed September 29, 2017, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–0–US–01];

2. PCT Patent Application No. PCT/US2018/051285 filed September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–PCT–01];

3. Australian Patent Application No. 2018342246 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–AU–02];

4. Brazilian Patent Application No. BR112020006012–7 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–BR–03];

5. Canadian Patent Application No. 3,077,024 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–CA–04];

6. Chinese Patent Application No. 201880074539.8 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–CN–05];

7. Costa Rican Application No. 2020–0170 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–CR–06];

8. Eurasian Application No. 202090757 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–EA–07];

9. European Patent Application No. 18780006.5 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–EP–08];

10. Israeli Patent Application No. 273515 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–IL–09];

11. Indian Patent Application No. 202047013911 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–IN–10];

12. Japanese Patent Application No. 2020–517556 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–JP–11];

13. Korean Patent Application No. 2020–7012344 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–KR–12];

14. Mexican Application No. MX/a/2020/003504 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53''

[HHS Reference No. E–237–2017–2–MX–13];

15. New Zealand Patent Application No. 763023 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–NZ–14];

16. Singapore Patent Application No. 11202002636P effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–SG–15];

17. United States Patent Application No. 16/651,242 effective filing date of September 17, 2018, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–US–16];

18. Hong Kong Patent Application No. 62020021272.3 filed November 30, 2020, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–HK–17];

19. Brazilian Patent Application No. BR122021018454–2 filed September 16, 2021, entitled ''T Cell Receptors Recognizing Mutated P53'' [HHS Reference No. E–237–2017–2–BR–18];

20. United States Provisional Patent Application No. 62/867,619 filed June 27, 2019, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–US–01];

21. PCT Patent Application No. PCT/US2020/039785, filed June 26, 2020, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–PCT–02];

22. Taiwanese Patent Application No. 109121744 filed June 26, 2020, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–TW–03];

23. Australian Patent Application No. 2020308004 filed January 6, 2022, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–AU–04];

24. Brazilian Patent Application No. BR112021026408–6 filed December 24, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–BR–05];

25. Canadian Patent Application No. 3,144,070 filed December 16, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–CA–06];

26. Chinese Patent Application No. 202080047882.0 filed December 27, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–CN–07];

27. European Patent Application No. 20742583.6 filed January 27, 2022, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–EP–08];

28. Indian Patent Application No. 202247003029 filed January 19, 2022, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–IN–09];

29. Japanese Patent Application No. 2021–576970 filed December 24, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–JP–10];

30. Mexican Patent Application No. MX/a/2021/015877 filed December 16, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–MX–11];

31. Russian Patent Application No. 2022101295 filed January 20, 2022, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–RU–12];

32. Singapore Patent Application No. 11202113949V filed December 15, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–SG–13];

33. South African Patent Application No. 2022/00598 filed January 12, 2022, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–ZA–14];

34. Korean Patent Application No. 2022–7002872 filed January 26, 2022, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–KR–15];

35. United States Patent Application No. 17/620,942 filed December 20, 2021, entitled ''T Cell Receptors Recognizing R175H or Y220C Mutation in P53'' [HHS Reference No. E–135–2019–0–US–16];

36. United States Provisional Patent Application No. 63/074,747 filed September 4, 2020, entitled ''T Cell Receptors Recognizing R273C or Y220C Mutation in P53'' [HHS Reference No. E–173–2020–0–US–01];

37. PCT Patent Application No. PCT/US2021/048786 filed September 2, 2021, entitled ''T Cell Receptors Recognizing R273C or Y220C Mutation in P53'' [HHS Reference No. E–173–2020–0–PCT–02];

38. Taiwanese Patent Application No. 110132552 filed September 2, 2021, entitled ''T Cell Receptors Recognizing R273C or Y220C Mutation in P53'' [HHS Reference No. E–173–2020–0–TW–03];

39. United States Provisional Patent Application No. 63/185,805 filed May 7, 2021, entitled ''T Cell Receptors Recognizing C135Y, R175H or M237I Mutation in P53'' [HHS Reference No. E–101–2021–0–US–01]; and

40. PCT Patent Application No. PCT/US2022/028066 filed May 6, 2022, entitled ''T Cell Receptors Recognizing C135Y, R175H or M237I Mutation in P53'' [HHS Reference No. E–101–2021–0–PCT–02].

Group C

1. United States Provisional Patent Application No. 62/004,335 filed May 29, 2014, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–US–01];

2. PCT Patent Application No. PCT/US2015/033129 filed May 29, 2015, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–PCT–02];

3. Australian Patent No. 2015266818 issued January 16, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–AU–03];

4. Brazilian Patent Application No. BR112016027805–4 effective filing date of May 29, 2015, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–BR–04];

5. Canadian Patent Application No. 2,950,192 effective filing date of May 29, 2015, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–CA–05];

6. Chinese Patent No. ZL201580031789.X issued May 4, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–CN–06];

7. European Patent No. 3149031 issued December 18, 2019, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–EP–07];

a. Validated in the following jurisdictions: AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MK, MT, NL, NO, PL, PT, RO, SE, SI, SK, SM and TR.

8. Israeli Patent No. 248797 issued September 1, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–IL–08];

9. Japanese Patent No. 6742991 issued August 19, 2020, entitled ''Anti-Human

Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–JP–09];

10. Korean Patent Application No. 2016–7033189 effective filing date of May 29, 2015, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–KR–10];

11. Mexican Patent No. 375379 issued September 25, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–MX–11];

12. Saudi Arabian Patent No. 7456 issued January 5, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–SA–12];

13. United States Patent No. 10,174,098 issued January 8, 2019, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–US–13];

14. Hong Kong Patent No. HK1236203 issued January 8, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–HK–14];

15. United States Patent No. 10,870,687 issued December 22, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–US–15];

16. European Patent Application No. 19217074.4 filed December 17, 2019, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–EP–16];

17. Australian Patent No. 2019283892 issued May 13, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–AU–17];

18. Japanese Patent No. 6997267 issued December 20, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–JP–53];

19. Saudi Arabian Patent Application No. 520412601 filed August 10, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–SA–54];

20. Hong Kong Patent Application No. 42020020661.3 filed November 24, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–HK–55];

21. Mexican Patent Application No. MX/a/2020/010035 filed September 24, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–MX–56];

22. United States Patent No. 11,434,272 issued September 6, 2020, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–US–57];

23. Australian Patent Application No. 2021202227 filed April 13, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–AU–58];

24. Chinese Patent Application No. 20210399056.9 filed April 14, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–CN–59];

25. Israeli Patent No. 282518 issued July 2, 2022, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–IL–60];

26. Hong Kong Patent Application No. 42022046605.6 filed January 19, 2022, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–HK–62];

27. Japanese Patent Application No. 2021–203953 filed December 16, 2021, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–JP–63];

28. Israeli Patent Application No. 290655 filed February 16, 2022, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–IL–64];

29. United States Patent Application No. 17/816,496 filed August 1, 2022, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–US–65]; and

30. Korean Patent Application No. 2022–7032043 filed September 15, 2022, entitled ''Anti-Human Papillomavirus 16 E7 T Cell Receptors'' [HHS Reference No. E–176–2014–0–KR–66].

Group D

1. United States Provisional Patent Application No. 61/535,086 filed September 15, 2011, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–US–01];

2. PCT Patent Application No. PCT/US2012/051623 filed September 11, 2012, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–PCT–02];

3. Australian Patent No. 2012309830 issued July 13, 2017, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–AU–03];

4. Canadian Patent No. 2,848,209 issued June 1, 2021, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–CA–04];

5. European Patent No. 2755997 issued July 4, 2018, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–EP–05];

a. Validated in the following jurisdictions: AT, BE, CH, CZ, DE, ES, FR, GB, GR, IE, IT, NL, NO, PL, PT, SE, SI, SK and TR.

6. Japanese Patent No. 6415322 issued October 12, 2018, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–JP–06];

7. United States Patent Application No. 14/344,354 filed March 14, 2014, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–US–07];

8. Chinese Patent Application No. 201280055972.X filed May 14, 2014, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–CN–08];

9. Israeli Patent No. 231323 issued November 30, 2019, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–IL–09];

10. Australian Patent No. 2017204103 issued June 20, 2019, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–AU–10];

11. European Patent No. 3392270 issued August 26, 2020, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–EP–11];

a. Validated in: AT, BE, CH, CZ, DE, ES, FR, GB, GR, IE, IT, NL, NO, PL, PT, SE, SI, SK and TR.

12. Chinese Patent Application No. 201811170958.X filed October 8, 2018, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–CN–14];

13. United States Patent No. 11,306,131 issued April 19, 2022, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–US–32];

14. Japanese Patent No. 6855426 issued March 19, 2021, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–JP–33];

15. Hong Kong Patent No. HK1262936 issued June 4, 2021, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–HK–34];

16. Hong Kong Patent Application No. 19129278.8 filed September 6, 2019, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–HK–35];

17. Israeli Patent No. 268157 issued July 30, 2021, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–IL–36];

18. European Patent Application No. 20192082.4 filed July 18, 2019, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–EP–37];

19. Israeli Patent No. 268157 issued June 2, 2022, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–IL–57];

20. Japanese Patent Application No. 2021–043845 filed March 17, 2021, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–JP–58];

21. Canadian Patent Application No. 3,114,877 filed April 13, 2021, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–CA–59];

22. Israeli Patent Application No. 290105 filed January 25, 2022, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–IL–60];

23. United States Patent Application No. 17/691,569 filed March 10, 2022, entitled ''T Cell Receptors Recognizing HLA–A1– or HLA–CW7–Restricted MAGE'' [HHS Reference No. E–266–2011–0–US–61];

24. United States Provisional Patent Application No. 61/701,056 filed September 14, 2012, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–US–01];

25. PCT Patent Application No. PCT/US2013/059608 filed September 13, 2013, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–PCT–02];

26. Australian Patent No. 2013315391 issued September 21, 2017, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–AU–03];

27. Canadian Patent Application No. 2,884,743 filed September 13, 2013, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–CA–04];

28. Chinese Patent No. ZL201380059102.4 issued September 24, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–CN–05];

29. European Patent No. 2895509 issued December 4, 2019, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–EP–06];

a. Validated in the following jurisdictions: AL, AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HR, HU, IE, IS, IT, LI, LT, LU, LV, MK, MT, NL, NO, PL, PT, RO, RS, SE, SI, SK, SM and TR.

30. Israeli Patent No. 237560 issued September 1, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–IL–07];

31. Japanese Patent No. 6461796 issued January 11, 2019, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–JP–08];

32. Korean Patent No. 2165350 issued October 6, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–KR–09];

33. Mexican Patent No. 367279 issued August 13, 2019, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–MX–10];

34. United States Patent No. 9,879,065 issued January 30, 2018, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–US–11];

35. Australian Patent No. 2017219019 issued August 22, 2019, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–AU–12];

36. United States Patent No. 10,611,815 issued April 7, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–US–13];

37. Japanese Patent No. 6728326 issued July 3, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–JP–14];

38. Australian Patent No. 2019213329 issued June 24, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–AU–15];

39. Mexican Patent Application No. MX/a/2019/009641 filed August 13, 2019, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–MX–16];

40. European Patent No. 3636665 issued June 29, 2022, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–EP–17];

a. Validated in: BE, DK, FR, DE, IT, NL, NO, ES, SE, CH and GB.

41. United States Patent Application No. 16/812,845 filed March 9, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–US–58];

42. Israeli Patent No. 274003 issued February 1, 2022, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–IL–59];

43. Japanese Patent Application No. 2020–114090 filed July 1, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–JP–60];

44. Hong Kong Patent Application No. 42020016865.6 filed September 25, 2020, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–HK–61];

45. Korean Patent No. 2303166 issued September 10, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–KR–62];

46. Australian Patent Application No. 2021203746 filed June 7, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–AU–63];

47. Japanese Patent Application No. 2021–124003 filed July 29, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–JP–64];

48. Chinese Patent Application No. 202111028896.0 filed September 1, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–CN–65];

49. Korean Patent No. 2370307 issued February 28, 2022, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–KR–66];

50. Israeli Patent Application No. 286786 filed September 29, 2021, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–IL–67];

51. Hong Kong Patent Application No. 42022051280.0 filed April 7, 2022, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–HK–68];

52. Korean Patent Application No. 10–2022–7006700 filed February 25, 2022, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–KR–69];

53. European Patent Application No. 22174521.9 filed May 20, 2022, entitled

''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–EP–70]; and

54. United States Patent Application No. 17/936,006 filed September 28, 2022, entitled ''T Cell Receptors Recognizing MHC Class II–Restricted Mage–A3'' [HHS Reference No. E–230–2012–0–US–82].

(and U.S. and foreign patent applications claiming priority to the aforementioned applications)

The patent rights in these inventions have been assigned and/or exclusively licensed to the government of the United States of America.

The prospective exclusive license territory may be worldwide, and the field of use may be limited to the following:

''Development, manufacture and commercialization of allogeneic Natural Killer (NK) cell therapy products engineered to express a therapeutic T cell receptor claimed in the Licensed Patent Rights for the treatment or prevention of cancer in humans.

Specifically excluded from this field of use are Natural Killer T (NKT) cell therapy products engineered via viral and non-viral means for the treatment of human cancers, wherein the NKT cell therapy product contains at least 50% NKT cells.''

Intellectual Property Group A is primarily directed to isolated T cell receptors (TCRs) reactive to mutated Kirsten rat sarcoma viral oncogene homolog (KRAS), within the context of several human leukocyte antigens (HLAs). Mutated KRAS, which plays a well-defined driver role in oncogenesis, is expressed by a variety of human cancers, including pancreatic, lung, endometrial, ovarian and prostate. Due to its restricted expression in precancerous and cancerous cells, this antigen may be targeted on mutant KRAS-expressing tumors with minimal normal tissue toxicity.

Intellectual Property Group B is primarily directed to isolated TCRs reactive to mutated tumor protein 53 (TP53 or P53), within the context of several HLAs. *P53* is the archetypal tumor suppressor gene and the most frequently mutated gene in cancer. Contemporary estimates suggest that >50% of all tumors carry mutations in *P53.* Because of its prevalence in cancer and its restricted expression to precancerous and cancerous cells, this antigen may be targeted on mutant P53-expressing tumors with minimal normal tissue toxicity.

Intellectual Property Group C is primarily directed to isolated TCRs reactive to the E7 oncoprotein of Human Papilloma Virus (HPV) type 16, within the context of HLA–A*02. E7 oncoprotein drives malignant transformation in HPV-infected cells. Due to its specific and constitutive expression in cancer cells, this antigen may be targeted in HPV-positive malignancies, such as cervical carcinoma and oropharyngeal carcinoma, with minimal normal tissue toxicity.

Intellectual Property Group D is primarily directed to isolated TCRs reactive to Melanoma-associated antigens 3, 6 and 12 (MAGE–A3/A6/A12), within the context of multiple HLAs. There are twelve MAGE–A superfamily antigens designated A1–A12. These antigens are among the most commonly expressed cancer testis antigens in a variety of tumors and are associated with poor disease prognosis. They are not expressed on normal cells other than non-MHC expressing germ cells of the testis, which do not generate an immune response. Thus, these antigens may be targeted on MAGE–A-expressing tumors with minimal normal tissue toxicity.

This notice is made in accordance with 35 U.S.C. 209 and 37 CFR part 404. The prospective exclusive license will be royalty bearing, and the prospective exclusive license may be granted unless within fifteen (15) days from the date of this published notice, the National Cancer Institute receives written evidence and argument that establishes that the grant of the license would not be consistent with the requirements of 35 U.S.C. 209 and 37 CFR part 404.

In response to this Notice, the public may file comments or objections. Comments and objections, other than those in the form of a license application, will not be treated confidentially, and may be made publicly available.

License applications submitted in response to this Notice will be presumed to contain business confidential information and any release of information in these license applications will be made only as required and upon a request under the Freedom of Information Act, 5 U.S.C. 552.

Dated: December 23, 2022.

Richard U. Rodriguez,

Associate Director, Technology Transfer Center, National Cancer Institute.

[FR Doc. 2022–28404 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Aging; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the National Advisory Council on Aging.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Advisory Council on Aging.

Date: September 19–20, 2023.

Closed: September 19, 2023, 3:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892 (Virtual Meeting).

Open: September 20, 2023, 10:00 a.m. to 2:00 p.m.

Agenda: Call to order and report from the Director; Discussion of future meeting dates; Consideration of minutes of last meeting; Reports from Task Force on Minority Aging Research, Working Group on Program; Council Speaker; Program Highlights.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892 (Virtual Meeting).

Closed: September 20, 2023, 2:00 p.m. to 2:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Kenneth Santora, Ph.D., Director, Office of Extramural Activities, National Institute on Aging, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20814, (301) 496–9322, *ksantora@nih.gov.*

Information is also available on the Institute's/Center's home page: *www.nia.nih.gov/about/naca,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.866, Aging Research, National Institutes of Health, HHS)

Dated: December 27, 2022.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–28457 Filed 12–29–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–HQ–LE–2022–N071; FF09L00000/FX/LE18110900000/223; OMB Control Number 1018–0092]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Federal Fish and Wildlife Applications and Reports—Law Enforcement

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of information collection; request for comment.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, we, the U.S. Fish and Wildlife Service (Service), are proposing to revise an existing information collection.

DATES: Interested persons are invited to submit comments on or before January 30, 2023.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *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. Please provide a copy of your comments to the Service Information Collection Clearance Officer, U.S. Fish and Wildlife Service, MS: PRB (JAO/3W), 5275 Leesburg Pike, Falls Church, VA 22041–3803 (mail); or by email to *Info_Coll@fws.gov.* Please reference ''1018–0092'' in the subject line of your comments.

FOR FURTHER INFORMATION CONTACT: To request additional information about this ICR, contact Madonna L. Baucum, Service Information Collection Clearance Officer, by email at *Info_Coll@fws.gov,* or by telephone at (703) 358–2503. Individuals in the United States who are deaf, deafblind, hard of hearing, or have a speech disability may dial 711 (TTY, TDD, or TeleBraille) to access telecommunications relay services. Individuals outside the United States should use the relay services offered within their country to make international calls to the point-of-contact in the United States.

SUPPLEMENTARY INFORMATION: In accordance with the Paperwork Reduction Act (PRA, 44 U.S.C. 3501 *et seq.*) and its implementing regulations at 5 CFR 1320.8(d)(1), all information collections require approval under the PRA. We may not conduct or sponsor and you are not required to respond to a collection of information unless it displays a currently valid OMB control number.

On September 23, 2022, we published in the **Federal Register** (87 FR 58122) a notice of our intent to request that OMB approve this information collection. In that notice, we solicited comments for 60 days, ending on November 22, 2022. In an effort to increase public awareness of, and participation in, our public commenting processes associated with information collection requests, the Service also published the **Federal Register** notice on *Regulations.gov* (Docket No. HQ–LE–2022–0119–0001) to provide the public with an additional method to submit comments (in addition to the typical *Info_Coll@fws.gov* email and U.S. mail submission methods). We received one comment in response to that notice which did not address the information collection requirements. No response is required.

As part of our continuing effort to reduce paperwork and respondent burdens, we invite the public and other Federal agencies to comment on new, proposed, revised, and continuing collections of information. This helps us assess the impact of our information collection requirements and minimize the public's reporting burden. It also helps the public understand our information collection requirements and provide the requested data in the desired format.

We are especially interested in public comment addressing the following:

(1) Whether or not the collection of information is necessary for the proper performance of the functions of the agency, including whether or not the information will have practical utility;

(2) The accuracy of our estimate of the burden for this collection of information, including the validity of the methodology and assumptions used;

(3) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(4) How might the agency minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of response.

Comments that you submit in response to this notice are a matter of public record. We will include or summarize each comment in our request to OMB to approve this ICR. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Abstract: The Endangered Species Act (ESA; 16 U.S.C. 1531 *et seq.*) makes it unlawful to import or export wildlife or wildlife products for commercial purposes without first obtaining an import/export license (see 16 U.S.C. 1538(d)). The ESA also requires that fish or wildlife be imported into or exported from the United States only at a designated port, or at a nondesignated port under certain limited circumstances (see 16 U.S.C. 1538(f)). This information collection includes the following permit/license application forms:

FWS Form 3–200–2, ''Designated Port Exception Permit''

Under 50 CFR 14.11, it is unlawful to import or export wildlife or wildlife products at ports other than those designated in 50 CFR 14.12, unless you qualify for an exception. The following exceptions allow qualified individuals, businesses, or scientific organizations to import or export wildlife or wildlife products at a nondesignated port:

(a) To export the wildlife or wildlife products for scientific purposes;

(b) To minimize deterioration or loss; or

(c) To relieve economic hardship.

To request authorization to import or export wildlife or wildlife products at nondesignated ports, applicants must complete FWS Form 3–200–2. Designated port exception permits can be valid for up to 2 years. We may require a permittee to file a report on activities conducted under authority of the permit.

FWS Form 3–200–3a, "Federal Fish and Wildlife Permit Application Form: Import/Export License—U.S. Entities," and 3–200–3b, "Federal Fish and Wildlife Permit Application Form: Import/Export License—Foreign Entities"

It is unlawful to import or export wildlife or wildlife products for commercial purposes without first obtaining an import/export license (50 CFR 14.91). Applicants located in the United States must complete FWS Form 3–200–3a to request this license. Foreign applicants that reside or are located outside the United States must complete FWS Form 3–200–3b to request this license.

We use the information collected on FWS Forms 3–200–3a and 3–200–3b as an enforcement tool and management aid to (a) monitor the international wildlife market and (b) detect trends and changes in the commercial trade of wildlife and wildlife products. Import/export licenses are valid for up to 1 year. We may require a licensee to file a report on activities conducted under authority of the import/export license.

Proposed Revision

With this submission, we propose to revise application form 3–200–2 to correct an error in the most recent revision of this collection which removed the tax identification number (Social Security Number or Employer Identification Number) field from the form. This critical information is used by wildlife inspectors and special agents during law enforcement investigations to ensure the identities of individuals are accurate and not mistaken while investigating wildlife crimes and to verify the applicant is the same person that had knowledge of wildlife laws and regulations.

Title of Collection: Federal Fish and Wildlife Applications and Reports—Law Enforcement; 50 CFR parts 13 and 14.

OMB Control Number: 1018–0092.

Form Number: FWS Forms 3–200–2, 3–200–3a, 3–200–3b, 3–200–44, and 3–200–44a.

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: Individuals, private sector, and State/local/Tribal entities.

Respondent's Obligation: Required to obtain or retain a benefit.

Frequency of Collection: On occasion for Forms 3–200–2, 3–200–3a, 3–200–3b, 3–200–44, and reporting requirements. Biannually for Form 3–200–44a.

Total Estimated Annual Nonhour Burden Cost: $1,188,700. There is a $100 fee associated with applications (Forms 3–200–2, 3–200–3a, and 3–200–3b) and a $150 fee associated with applications (Form 3–200–44) received from individuals and the private sector. There is no fee for applications from government agencies or for processing reports.

Activity/requirement	Estimated number of annual respondents	Estimated number of annual responses	Total estimated annual responses	Completion time per response (hours)	Estimated total annual burden hours *
FWS Form 3–200–2, "Designated Port Exception Permit" ***(50 CFR parts 13 and 14) (Hardcopy)***					
Individuals	289	1	289	1.25	361
Private Sector	361	1	361	1.25	451
Government	7	1	7	1.25	9
FWS Form 3–200–2, "Designated Port Exception Permit" ***(50 CFR parts 13 and 14) (eLicense)***					
Individuals	289	1	289	1	289
Private Sector	361	1	361	1	361
Government	7	1	7	1	7
FWS Form 3–200–3a, "Federal Fish and Wildlife Permit Application Form: Import/Export License-U.S. Entities" ***(50 CFR parts 13 and 14) (Hardcopy)***					
Private Sector	5,099	1	5,099	1.25	6,374
FWS Form 3–200–3a, "Federal Fish and Wildlife Permit Application Form: Import/Export License-U.S. Entities" ***(50 CFR parts 13 and 14) (eLicense)***					
Private Sector	5,099	1	5,099	1	5,099
FWS Form 3–200–3b, "Federal Fish and Wildlife Permit Application Form: Import/Export License-Foreign Entities" ***(50 CFR parts 13 and 14) (Hardcopy)***					
Private Sector	190	1	190	1.25	238
FWS Form 3–200–3b, "Federal Fish and Wildlife Permit Application Form: Import/Export License-Foreign Entities" ***(50 CFR parts 13 and 14) (eLicense)***					
Private Sector	190	1	190	1	190
Designated Port Exception Permit Report ***(50 CFR parts 13 and 14)***					
Private Sector	5	1	5	1	5
Import/Export License Report ***(50 CFR parts 13 and 14)***					
Private Sector	10	1	10	1	10

Activity/requirement	Estimated number of annual respondents	Estimated number of annual responses	Total estimated annual responses	Completion time per response (hours)	Estimated total annual burden hours *
FWS Forms 3–200–44, "Permit Application Form: Registration of an Agent/Tannery under the Marine Mammal Protection Act (MMPA)" *(Hardcopy)*					
Private Sector	3	1	3	.3	1
FWS Forms 3–200–44, "Permit Application Form: Registration of an Agent/Tannery under the Marine Mammal Protection Act (MMPA)" *(ePermits)*					
Private Sector	3	1	3	.25	1
FWS Form 3–200–44a, "Registered Agent/Tannery Bi-Annual Inventory Report" *(Hardcopy)*					
Private Sector	10	2	20	1	20
FWS Form 3–200–44a, "Registered Agent/Tannery Bi-Annual Inventory Report" *(ePermits)*					
Private Sector	10	2	20	.75	15
Total:	11,933	....	11,953	....	13,431

* Rounded to Match ROCIS.

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 authority for this action is the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Madonna Baucum,

Information Collection Clearance Officer, U.S. Fish and Wildlife Service.

[FR Doc. 2022–28426 Filed 12–29–22; 8:45 am]

BILLING CODE 4333–15–P

INTERNATIONAL TRADE COMMISSION

[Inv. No. 337–TA–1347]

Institution of Investigation; Certain Location-Sharing Systems, Related Software, Components Thereof, and Products Containing Same

AGENCY: U.S. International Trade Commission.

ACTION: Notice.

SUMMARY: Notice is hereby given that a complaint was filed with the U.S. International Trade Commission on November 16, 2022, under section 337 of the Tariff Act of 1930, as amended, on behalf of Advanced Ground Information Systems, Inc. of Jupiter, Florida and AGIS Software Development LLC of Marshall, Texas. The complaint was supplemented on December 13, 2022. The complaint, as supplemented, alleges violations of section 337 based upon the importation into the United States, the sale for importation, and the sale within the United States after importation of certain location-sharing systems, related software, components thereof, and products containing same by reason of the infringement of certain claims of U.S. Patent No. 8,213,970 (''the '970 patent''); U.S. Patent No. 9,467,838 (''the '838 patent''); U.S. Patent No. 9,445,251 (''the '251 patent''); U.S. Patent No. 9,749,829 (''the '829 patent''); and U.S. Patent No. 9,820,123 (''the '123 patent''). The complaints further allege that an industry in the United States exists as required by the applicable Federal Statute. The complainants request that the Commission institute an investigation and, after the investigation, issue a limited exclusion order and cease and desist orders.

ADDRESSES: The complaint, except for any confidential information contained therein, may be viewed on the Commission's electronic docket (EDIS) at *https://edis.usitc.gov.* For help accessing EDIS, please email *EDIS3Help@usitc.gov.* Hearing impaired individuals are advised that information on this matter can be obtained by contacting the Commission's TDD terminal on (202) 205–1810. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at (202) 205–2000. General information concerning the Commission may also be obtained by accessing its internet server at *https://www.usitc.gov.*

FOR FURTHER INFORMATION CONTACT: Pathenia M. Proctor, The Office of Unfair Import Investigations, U.S. International Trade Commission, telephone (202) 205–2560.

SUPPLEMENTARY INFORMATION:

Authority: The authority for institution of this investigation is contained in section 337 of the Tariff Act of 1930, as amended, 19 U.S.C. 1337, and in section 210.10 of the Commission's Rules of Practice and Procedure, 19 CFR 210.10 (2021).

Scope of Investigation: Having considered the complaint, the U.S. International Trade Commission, on December 22, 2022, *ordered that*—

(1) Pursuant to subsection (b) of section 337 of the Tariff Act of 1930, as amended, an investigation be instituted to determine whether there is a violation of subsection (a)(1)(B) of section 337 in the importation into the United States, the sale for importation, or the sale within the United States after importation of certain products identified in paragraph (2) by reason of infringement of one or more of claims 2 and 10–13 of the '970 patent; claims 1, 3, 5–10, 16, 19, 25, 38, 40, 54–56, 61–64, 68, 71, 72, 80 and 84 of the '838 patent; claims 1, 2, 5, 7, 8, 23–25, 28–31, and 35 of the '251 patent; claims 1, 8, 34, 35, 41, and 68 of the '829 patent; claims 14 and 36–38 of the '123 patent, and whether an industry in the United States exists as required by subsection (a)(2) of section 337;

(2) Pursuant to section 210.10(b)(1) of the Commission's Rules of Practice and Procedure, 19 CFR 210.10(b)(1), the plain language description of the accused products or category of accused products, which defines the scope of the investigation, is ''mobile devices containing location-sharing software, mobile phones and tablets containing location-sharing software, notebook and laptop computers containing location-

sharing software, and associated components thereof'';

(3) Pursuant to Commission Rule 210.50(b)(l), 19 CFR 210.50(b)(1), the presiding administrative law judge shall take evidence or other information and hear arguments from the parties or other interested persons with respect to the public interest in this investigation, as appropriate, and provide the Commission with findings of fact and a recommended determination on this issue, which shall be limited to the statutory public interest factors set forth in 19 U.S.C. 1337(d)(l), (f)(1), (g)(1);

(4) For the purpose of the investigation so instituted, the following are hereby named as parties upon which this notice of investigation shall be served:

(a) The complainants are:

Advanced Ground Information Systems, Inc., 92 Lighthouse Dr., Jupiter, FL 33469
AGIS Software Development LLC, 100 West Houston Street, Marshall, TX 75671

(b) The respondents are the following entities alleged to be in violation of section 337, and are the parties upon which the complaint is to be served:

Google LLC, 1600 Amphitheatre Parkway, Mountain View, CA 94043
Samsung Electronics, Co., Ltd., 12 Samsung-Ro, Maetan-3dong, Yeongtong-gu, Suwon, 443–742, Republic of Korea
Samsung Electronics America, Inc., 85 Challenger Rd., Ridgefield Park, New Jersey 07660
OnePlus Technology (Shenzhen) Co., Ltd., 18F, Tairan Building, Block C, Tairan 8th Road, Chgongmiao, Futian District, Shenzhen, Guangdong 518040, China
TCL Technology Group Corporation, 22/F, TCL Technology, Building, No. 17, Huifeng 3rd Road, Zhongkai High-Tech Development District, Huizhou, Guangdong, China 516006
TCL Electronics Holdings Limited, 7th Floor, Building 22E, 22 Science Park East Avenue, Hong Kong Science Park, Hong Kong
TCL Communication Technology Holdings, Limited, 5/F, Building 22E, 22 Science Park East Avenue, Hong Kong Science Park, Shatin, New Territories, Hong Kong
TCT Mobile (US) Inc., 25 Edelman, Suite 200, Irvine, CA 92618
Lenovo Group Ltd., 6 Chuang ye Road, Haidian District, Beijing 100085, China
Lenovo (United States) Inc., 1009 Think Place, Building One, Morrisville, NC 27560
Motorola Mobility LLC, 222 W Merchandise Mart Plaza, Suite 1800, Chicago, IL 60654
HMD Global, Karaportti 2, FIN–02610, Espoo, Finland
HMD Global OY, Bertel Jungin aukio 9, 02600, Espoo, Finland
HMD America, Inc., 1200 Brickell Ave., Suite 510, Miami, FL 33131
Sony Corporation, 1–7–1 Konan Minato-ku, Tokyo, 108–0075, Japan
Sony Mobile Communications, Inc., 4–12–3 Higashi-Shinagawa, Shinagawa-ku, Tokyo, 140–0002, Japan
ASUSTek Computer Inc., No. 15, Li-Te Rd., Beitou Dist., Taipei 112, Taiwan
ASUS Computer International, 48720 Kato Rd., Fremont, CA 94538
BLU Products, 10814 NW 33rd Street, Doral, FL 33172
Panasonic Corporation, 1006 Oaza Kadoma-shi, Kadoma 571–8501, Osaka, Japan
Panasonic Corporation of North America, 1 Panasonic Way, Secaucus, New Jersey 07094
Kyocera Corporation, 6 Takeda Tobadono-cho, Fushmi-ku, Kyoto, Japan 612–8501
Xiaomi Corporation, Maples Corporate Services Limited, P.O. Box 309, Ugland House, Grand Cayman, KY1–1104, Cayman Islands
Xiaomi H.K. Ltd., Unit 806, Tower 2 8/F, Cheung Sha Wan Plaza, 833 Cheung Sha Wan Road, Kowloon City, Hong Kong
Xiaomi Communications Co., Ltd., Xiaomi Office Building, 68 Qinghe Middle Street, Haidian District, Beijing, China 100085
Xiaomi Inc., Xiaomi Office Building, 68 Qinghe Middle Street, Haidian District, Beijing, China 100085

(c) The Office of Unfair Import Investigations, U.S. International Trade Commission, 500 E Street SW, Suite 401, Washington, DC 20436; and

(5) For the investigation so instituted, the Chief Administrative Law Judge, U.S. International Trade Commission, shall designate the presiding Administrative Law Judge.

Responses to the complaint, as supplemented, and the notice of institution of investigation must be submitted by the named respondents in accordance with section 210.13 of the Commission's Rules of Practice and Procedure, 19 CFR 210.13. Pursuant to 19 CFR 201.16(e) and 210.13(a), as amended in 85 FR 15798 (March 19, 2020), such responses will be considered by the Commission if received not later than 20 days after the date of service by the complainants of the complaint and the notice of investigation. Extensions of time for submitting responses to the complaint and the notice of investigation will not be granted unless good cause therefor is shown.

Failure of a respondent to file a timely response to each allegation in the complaint and in this notice may be deemed to constitute a waiver of the right to appear and contest the allegations of the complaint and this notice, and to authorize the administrative law judge and the Commission, without further notice to the respondent, to find the facts to be as alleged in the complaint and this notice and to enter an initial determination and a final determination containing such findings, and may result in the issuance of an exclusion order or a cease and desist order or both directed against the respondent.

By order of the Commission.

Issued: December 22, 2022.

Katherine Hiner,

Acting Secretary to the Commission.

[FR Doc. 2022–28408 Filed 12–29–22; 8:45 am]

BILLING CODE 7020–02–P

INTERNATIONAL TRADE COMMISSION

[Investigation No. 337–TA–1266]

Certain Wearable Electronic Devices With ECG Functionality and Components Thereof; Notice of the Commission's Final Determination Finding a Violation of Section 337; Issuance and Suspension of a Limited Exclusion Order and a Cease and Desist Order; Termination of the Investigation

AGENCY: U.S. International Trade Commission.

ACTION: Notice.

SUMMARY: Notice is hereby given that the U.S. International Trade Commission (''Commission'') has determined that there is a violation of section 337 in the above-captioned investigation. The Commission has further determined to issue a limited exclusion order and a cease and desist order and to set a bond in the amount of $2 per unit of covered articles imported or sold during the period of Presidential review. The enforcement of these orders, including the bond provision, is suspended pending final resolution of the U.S. Patent and Trademark Office, Patent Trial and Appeal Board's (''PTAB'') Final Written Decisions finding the asserted patent claims unpatentable.

FOR FURTHER INFORMATION CONTACT: Panyin A. Hughes, Office of the General

Counsel, U.S. International Trade Commission, 500 E Street SW, Washington, DC 20436, telephone (202) 205–3042. Copies of non-confidential documents filed in connection with this investigation may be viewed on the Commission's electronic docket (EDIS) at *https://edis.usitc.gov.* For help accessing EDIS, please email *EDIS3Help@usitc.gov.* General information concerning the Commission may also be obtained by accessing its internet server at *https://www.usitc.gov.* Hearing-impaired persons are advised that information on this matter can be obtained by contacting the Commission's TDD terminal, telephone (202) 205–1810.

SUPPLEMENTARY INFORMATION: On May 26, 2021, the Commission instituted this investigation based on a complaint filed by AliveCor, Inc. of Mountain View, California (''AliveCor''). 86 FR 28382 (May 26, 2021). The complaint alleged violations of section 337 based on the importation into the United States, the sale for importation, or the sale within the United States after importation of certain wearable electronic devices with ECG functionality and components thereof by reason of infringement of one or more of claims 1–30 of U.S. Patent No. 10,595,731 (''the '731 patent''); claims 1–23 of U.S. Patent No. 10,638,941 (''the '941 patent''); and claims 1–4, 6–14, 16–20 of U.S. Patent No. 9,572,499 (''the '499 patent''). *Id.* The Commission's notice of investigation named Apple Inc. of Cupertino, California (''Apple'') as the sole respondent. The Office of Unfair Import Investigations (''OUII'') is named as a party in this investigation. *Id.*

On February 23, 2022, the ALJ issued an initial determination granting AliveCor's motion to terminate the investigation as to (1) claims 1–4, 6–14, and 18–20 of the '499 patent; (2) claims 2, 4, 6, 7, 11, 13, 14, and 17–30 of the '731 patent; and (3) claims 1–11, 14, 15, 17, and 18 of the '941 patent based upon withdrawal of allegations from the complaint as to those claims. Order No. 16 (Feb. 23, 2022), *unreviewed by* Notice (Mar. 18, 2022).

On June 27, 2022, the ALJ issued the final initial determination (''ID'') finding a violation of section 337 as to the '941 and '731 patents, and no violation of section 337 as to the '499 patent. The ID found that the parties do not contest personal jurisdiction and that the Commission has *in rem* jurisdiction over the accused products. ID at 18. The ID further found that the importation requirement under 19 U.S.C. 1337(a)(1)(B) is satisfied. *Id.* (citing CX–0904C (Apple stipulating that it imports the accused products into the United States)). Regarding the '941 patent, the ID found that AliveCor has proven infringement of the asserted claims, claims 12, 13, 19, and 20–23, and that Apple failed to show that any of the asserted claims are invalid. *Id.* at 30–45, 60–98. For the '731 patent, the ID found that AliveCor has proven infringement of the asserted claims, claims 1, 3, 5, 8–10, 12, 15, and 16, but that Apple has proven that claims 1, 8, 12, and 16 are invalid for obviousness. *Id.* at 105–108, 113–127. For the '499 patent, the ID found that AliveCor failed to prove infringement of the asserted claims, claims 16 and 17, and that claim 17 is invalid for lack of patentable subject matter under 35 U.S.C. 101. *Id.* at 129–138, 140–152. Finally, the ID found that AliveCor has proven the existence of a domestic industry that practices the asserted patents as required by 19 U.S.C. 1337(a)(2). *Id.* at 152–183. The ID included the ALJ's recommended determination on remedy and bonding (''RD''). The RD recommended that, should the Commission find a violation, issuance of a limited exclusion order and a cease and desist order would be appropriate. ID/RD at 190–193. The RD also recommended imposing no bond for covered products imported during the period of Presidential review. ID at 193–95.

On July 11, 2022, Apple filed a petition for review of the ID, and AliveCor filed a combined petition and contingent petition for review of the ID. On July 19, 2022, the private parties and OUII's investigative attorney filed responses to the petitions.

On September 22, 2022, the Commission determined to review the final ID in part. 87 FR 58819–21 (Sept. 28, 2022). Specifically, the Commission determined to review the final ID's invalidity findings, including patent eligibility under 35 U.S.C. 101 and obviousness under 35 U.S.C. 103, and the economic prong of the domestic industry requirement for all three patents. *Id.* The Commission requested briefing from the parties on certain issues under review. The Commission requested briefing from the parties, interested government agencies, and interested persons on remedy, the public interest, and bonding. *Id.*

On October 6, 2022, the parties filed initial submissions in response to the Commission's request for briefing. On October 14, 2022, the parties filed reply submissions. On October 21, 2022, Apple moved for leave to file a sur-reply to AliveCor's reply submission. On October 24, 2022, AliveCor filed an opposition. OUII filed a response in opposition on November 2, 2022.

The Commission has determined to deny Apple's motion for leave to file a sur-reply to AliveCor's reply submission.

On December 7, 2022, Apple filed an emergency motion, asking ''the Commission to suspend any remedial orders or, in the alternative, extend the December 12, 2022 Target Date of its Final Determination and stay all proceedings prior to issuance of any Final Determination pending final resolution of any appeal of the PTAB's decisions'' finding the asserted patent claims unpatentable. Apple Emergency Motion at 1. On December 9, 2022, AliveCor filed an opposition to Apple's motion. On December 16, 2022, OUII filed a response in support of Apple's motion, but only to the extent that any remedy the Commission issues be suspended pending appeal of the PTAB decisions. OUII Reply to Emergency Motion at 4.

Upon review of the parties' submissions, the ID, the RD, evidence of record, and public interest filings, the Commission has determined that Apple violated section 337 by reason of importation and sale of articles that infringe asserted claims 12, 13, and 19–23 of the '941 patent; and claims 1, 3, 5, 8–10, 12, 15, and 16 of the '731 patent. Regarding the issues under review, the Commission has determined to affirm the ID's economic prong of the domestic industry findings with the modifications described in the accompanying Commission opinion. Concerning invalidity, the Commission has determined to affirm the ID's patent eligibility findings under 35 U.S.C. 101 as to one claim with modifications explained in the Commission opinion and reverse as to another; and to correct the ID for not considering objective indicia of non-obviousness for certain asserted claims. For remedy, the Commission has determined to issue a limited exclusion order prohibiting further importation of infringing products and a cease and desist order against Apple. The Commission has determined that the public interest factors do not counsel against issuing remedial orders. The Commission has determined that a bond in the amount of $2 per unit of covered articles is required for covered products imported or sold during the period of Presidential review.

The enforcement of these orders, including the bond provision, is suspended pending final resolution of the PTAB's Final Written Decisions finding the asserted patent claims unpatentable. *See* 35 U.S.C. 318(b); *Apple, Inc.* v. *AliveCor, Inc.,* IPR2021–00971, Patent 10,595,731, Final Written

Decision Determining All Challenged Claims Unpatentable (Dec. 6, 2022); *Apple, Inc.* v. *AliveCor, Inc.,* IPR2021–00972, Patent 10,638,941, Final Written Decision Determining All Challenged Claims Unpatentable (Dec. 6, 2022).

The Commission's vote on this determination took place on December 22, 2022.

The authority for the Commission's determination is contained in section 337 of the Tariff Act of 1930, as amended (19 U.S.C. 1337), and in Part 210 of the Commission's Rules of Practice and Procedure (19 CFR part 210).

By order of the Commission.

Issued: December 22, 2022.

Katherine Hiner,

Acting Secretary to the Commission.

[FR Doc. 2022–28409 Filed 12–29–22; 8:45 am]

BILLING CODE 7020–02–P

DEPARTMENT OF JUSTICE

[OMB Number 1190–0018]

Agency Information Collection Activities; Proposed eCollection; eComments Requested; Extension of a Currently Approved Collection; Immigration-Related Unfair Employment Practices Charge Form (IER–1)

AGENCY: Civil Rights Division, Department of Justice.

ACTION: 30-Day notice.

SUMMARY: The Civil Rights Division, Department of Justice, will be submitting the following information collection request to the Office of Management and Budget for review and approval in accordance with the Paperwork Reduction Act of 1995.

DATES: The purpose of this notice is to allow for an additional 30 days for public comment until January 30, 2023.

FOR FURTHER INFORMATION CONTACT: If you have comments especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact Alberto Ruisanchez, Deputy Special Counsel, USDOJ–CRT–OSC, 950 Pennsylvania Avenue NW–4CON, Washington, DC 20530 or via phone at 202–305–1291. Written comments and/or suggestions can also be directed to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention Department of Justice Desk Officer, Washington, DC 20503 or sent to *OIRA_submissions@omb.eop.gov.*

SUPPLEMENTARY INFORMATION: Written comments and/or suggestions are requested from the public and affected agencies concerning the proposed collection of information. Your comments should address one or more of the following four points:

- Evaluate whether the collection of information is necessary for the proper performance of the function of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the collection of information, including the validity of the methodology and assumptions used;
- Evaluate whether and, if so, how the quality, utility, and clarity of the information to be collected can be enhanced; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, mechanical, or other technological collection techniques or other forms of information technology.

Overview of This Information Collection:

1. *Type of Information Collection:* Extension of Currently Approved Collection.

2. *The Title of the Form/Collection:* Title of the Form/Collection: IER Charge Form.

3. *Agency form number, if any, and agency component sponsoring the collection:*

Agency form number: Form IER–1.

Component Sponsor: Civil Rights Division, Department of Justice.

4. *Affected public who will be asked to respond, as well as a brief abstract:* Primary: The Immigrant and Employee Rights Section (IER) enforces the anti-discrimination provision (§ 274B) of the Immigration and Nationality Act (INA), 8 U.S.C. 1324b. The statute prohibits: (1) citizenship or immigration status discrimination in hiring, firing, or recruitment or referral for a fee, (2) national origin discrimination in hiring, firing, or recruitment or referral for a fee, (3) unfair documentary practices during the employment eligibility verification process (Form I–9 and E-Verify), and (4) retaliation or intimidation for asserting rights covered by the statute. IER, within the Department's Civil Rights Division, investigates and, where reasonable cause is found, litigates charges alleging discrimination. IER also initiates independent investigations, at times based on information developed during individual charge investigations. Independent investigations normally involve alleged discriminatory policies that potentially affect many employees or applicants. These investigations may result in complaints alleging a pattern or practice of discriminatory activity. If the Department lacks jurisdiction over a particular charge but believes another agency has jurisdiction over the claim, IER forwards the charge to the applicable Federal, state or local agency for any action deemed appropriate.

5. *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 320 individuals will complete each form annually; each response will be completed in approximately 30 minutes.

6. *An estimate of the total public burden (in hours) associated with the collection:* There are an estimated 160 total annual burden hours associated with this collection.

If additional information is required contact: Robert Houser, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, United States Department of Justice, Two Constitution Square, 145 N Street NE, Suite 3E.206, Washington, DC 20530.

Dated: December 22, 2022.

Robert Houser,

Department Clearance Officer, Policy and Planning Staff, Office of the Chief Information Officer, U.S. Department of Justice.

[FR Doc. 2022–28209 Filed 12–29–22; 8:45 am]

BILLING CODE 4410–13–P

NUCLEAR REGULATORY COMMISSION

[NRC–2022–0001]

Sunshine Act Meetings

TIME AND DATE: Weeks of January 2, 9, 16, 23, 30, February 6, 2023. The schedule for Commission meetings is subject to change on short notice. The NRC Commission Meeting Schedule can be found on the internet at: *https://www.nrc.gov/public-involve/public-meetings/schedule.html.*

PLACE: The NRC provides reasonable accommodation to individuals with disabilities where appropriate. If you need a reasonable accommodation to participate in these public meetings or need this meeting notice or the transcript or other information from the public meetings in another format (*e.g.,* braille, large print), please notify Anne Silk, NRC Disability Program Specialist, at 301–287–0745, by videophone at 240–428–3217, or by email at *Anne.Silk@nrc.gov.* Determinations on requests for reasonable accommodation will be made on a case-by-case basis.

STATUS: Public.

Members of the public may request to receive the information in these notices electronically. If you would like to be added to the distribution, please contact the Nuclear Regulatory Commission, Office of the Secretary, Washington, DC 20555, at 301–415–1969, or by email at *Wendy.Moore@nrc.gov* or *Tyesha.Bush@nrc.gov.*

MATTERS TO BE CONSIDERED:

Week of January 2, 2023

There are no meetings scheduled for the week of January 2, 2023.

Week of January 9, 2023—Tentative

There are no meetings scheduled for the week of January 9, 2023.

Week of January 16, 2023—Tentative

There are no meetings scheduled for the week of January 16, 2023.

Week of January 23, 2023

Tuesday, January 24, 2023

9:00 a.m. Overview of Accident Tolerant Fuel Activities (Public Meeting) (Contact: Samantha Lav: 301–415–3487)

Additional Information: The meeting will be held in the Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland. The public is invited to attend the Commission's meeting in person or watch live via webcast at the Web address—*https://video.nrc.gov/.*

Thursday, January 26, 2023

9:00 a.m. Strategic Programmatic Overview of the Decommissioning and Low-Level Waste and Nuclear Materials Users Business Lines (Public Meeting) (Contacts: Annie Ramirez: 301–415–6780; Candace Spore: 301–415–8537)

Additional Information: The meeting will be held in the Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland. The public is invited to attend the Commission's meeting in person or watch live via webcast at the Web address—*https://video.nrc.gov/.*

Week of January 30, 2023—Tentative

There are no meetings scheduled for the week of January 30, 2023.

Week of February 6, 2023

Thursday, February 9, 2023

9:00 a.m. Advanced Reactor Licensing under 10 CFR parts 50 and 52 (Public Meeting) (Contact: Omid Tabatabai: 301–415–6616)

Additional Information: The meeting will be held in the Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland. The public is invited to attend the Commission's meeting in person or watch live via webcast at the Web address—*https://video.nrc.gov/.*

CONTACT PERSON FOR MORE INFORMATION: For more information or to verify the status of meetings, contact Wesley Held at 301–287–3591 or via email at *Wesley.Held@nrc.gov.*

The NRC is holding the meetings under the authority of the Government in the Sunshine Act, 5 U.S.C. 552b.

Dated: December 28, 2022.

For the Nuclear Regulatory Commission.

Monika G. Coflin,

Technical Coordinator, Office of the Secretary.

[FR Doc. 2022–28504 Filed 12–28–22; 11:15 am]

BILLING CODE 7590–01–P

POSTAL REGULATORY COMMISSION

[Docket Nos. CP2021–51; MC2023–96 and CP2023–97]

New Postal Products

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is noticing a recent Postal Service filing for the Commission's consideration concerning a negotiated service agreement. This notice informs the public of the filing, invites public comment, and takes other administrative steps.

DATES: *Comments are due:* January 3, 2023.

ADDRESSES: Submit comments electronically via the Commission's Filing Online system at *http://www.prc.gov.* Those who cannot submit comments electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section by telephone for advice on filing alternatives.

FOR FURTHER INFORMATION CONTACT: David A. Trissell, General Counsel, at 202–789–6820.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction

The Commission gives notice that the Postal Service filed request(s) for the Commission to consider matters related to negotiated service agreement(s). The request(s) may propose the addition or removal of a negotiated service agreement from the Market Dominant or the Competitive product list, or the modification of an existing product currently appearing on the Market Dominant or the Competitive product list.

Section II identifies the docket number(s) associated with each Postal Service request, the title of each Postal Service request, the request's acceptance date, and the authority cited by the Postal Service for each request. For each request, the Commission appoints an officer of the Commission to represent the interests of the general public in the proceeding, pursuant to 39 U.S.C. 505 (Public Representative). Section II also establishes comment deadline(s) pertaining to each request.

The public portions of the Postal Service's request(s) can be accessed via the Commission's website (*http://www.prc.gov*). Non-public portions of the Postal Service's request(s), if any, can be accessed through compliance with the requirements of 39 CFR 3011.301.[1]

The Commission invites comments on whether the Postal Service's request(s) in the captioned docket(s) are consistent with the policies of title 39. For request(s) that the Postal Service states concern Market Dominant product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3622, 39 U.S.C. 3642, 39 CFR part 3030, and 39 CFR part 3040, subpart B. For request(s) that the Postal Service states concern Competitive product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3632, 39 U.S.C. 3633, 39 U.S.C. 3642, 39 CFR part 3035, and 39 CFR part 3040, subpart B. Comment deadline(s) for each request appear in section II.

II. Docketed Proceeding(s)

1. *Docket No(s).:* CP2021–51; *Filing Title:* USPS Notice of Amendment to Priority Mail & First-Class Package Service Contract 183, Filed Under Seal; *Filing Acceptance Date:* December 22, 2022; *Filing Authority:* 39 CFR 3035.105; *Public Representative:* Christopher C. Mohr; *Comments Due:* January 3, 2023.

2. *Docket No(s).:* MC2023–96 and CP2023–97; *Filing Title:* USPS Request to Add Priority Mail Express, Priority Mail, First-Class Package Service & Parcel Select Contract 105 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing*

[1] *See* Docket No. RM2018–3, Order Adopting Final Rules Relating to Non-Public Information, June 27, 2018, Attachment A at 19–22 (Order No. 4679).

Acceptance Date: December 22, 2022; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Arif Hafiz; *Comments Due:* January 3, 2023.

This Notice will be published in the **Federal Register**.

Erica A. Barker,

Secretary.

[FR Doc. 2022–28425 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL SERVICE

Product Change—Priority Mail Express, Priority Mail, First-Class Package Service, and Parcel Select Service Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 23, 2022, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Express, Priority Mail, First-Class Package Service, and Parcel Select Service Contract 106 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–100, CP2023–101.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28416 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and Parcel Select Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean C. Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 23, 2022, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail & Parcel Select Contract 7 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–98, CP2023–99.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28419 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Parcel Select Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 23, 2022, it filed with the Postal Regulatory Commission a *USPS Request to Add Parcel Select Contract 57 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–99, CP2023–100.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28415 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and Parcel Select Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean C. Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 21, 2022, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail & Parcel Select Contract 6 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–95, CP2023–96.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28418 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 23, 2022, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Contract 774 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–97, CP2023–98.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28414 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail Express, Priority Mail, First-Class Package Service, and Parcel Select Service Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 22, 2022, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Express, Priority Mail, First-Class Package Service, and Parcel Select Service Contract 105 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–96, CP2023–97.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28413 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail Express, Priority Mail, & First-Class Package Service Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* December 30, 2022.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on December 19, 2022, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Express, Priority Mail, & First-Class Package Service Contract 80 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2023–94, CP2023–95.

Sarah Sullivan,

Attorney, Ethics & Legal Compliance.

[FR Doc. 2022–28417 Filed 12–29–22; 8:45 am]

BILLING CODE 7710–12–P

SOCIAL SECURITY ADMINISTRATION

[Docket No: SSA–2022–0067]

Agency Information Collection Activities: Proposed Request and Comment Request

The Social Security Administration (SSA) publishes a list of information collection packages requiring clearance by the Office of Management and Budget (OMB) in compliance with Public Law 104–13, the Paperwork Reduction Act of 1995, effective October 1, 1995. This notice includes revisions of OMB-approved information collections and one new collection.

SSA is soliciting comments on the accuracy of the agency's burden estimate; the need for the information; its practical utility; ways to enhance its quality, utility, and clarity; and ways to minimize burden on respondents, including the use of automated collection techniques or other forms of information technology. Mail, email, or fax your comments and recommendations on the information collection(s) to the OMB Desk Officer and SSA Reports Clearance Officer at the following addresses or fax numbers.

(OMB) Office of Management and Budget, Attn: Desk Officer for SSA, Comments: *https://www.reginfo.gov/public/do/PRAMain.* Submit your comments online referencing Docket ID Number [SSA–2022–0067].

(SSA) Social Security Administration, OLCA, Attn: Reports Clearance Director, 3100 West High Rise, 6401 Security Blvd., Baltimore, MD 21235, Fax: 410–966–2830, Email address: *OR.Reports.Clearance@ssa.gov.*

Or you may submit your comments online through *https://www.reginfo.gov/public/do/PRAMain,* referencing Docket ID Number [SSA–2022–0067].

I. The information collections below are pending at SSA. SSA will submit them to OMB within 60 days from the date of this notice. To be sure we consider your comments, we must receive them no later than February 28, 2023. Individuals can obtain copies of the collection instruments by writing to the above email address.

1. Vocational Resource Facilitator Demonstration—0960–NEW. SSA is undertaking the Vocational Resource Facilitator Demonstration (VRFD) under the Interventional Cooperative Agreement Program (ICAP). ICAP allows SSA to partner with various non-federal groups and organizations to advance interventional research connected to the Supplemental Security Income (SSI) and Social Security Disability Insurance (SSDI) programs. VRFD will test the Vocational Resource Facilitator (VRF) intervention, which helps newly injured spinal cord injury or disease (SCI) or brain injury (BI) patients pursue their employment goals. The VRFD will provide empirical evidence on the impact of the intervention on patients in several critical areas: (1) employment and earnings; (2) SSI and SSDI benefit receipt; and (3) satisfaction and well-being. A rigorous evaluation of VRFD is critical to help SSA and other interested parties assess promising options to improve employment-related outcomes and decrease benefit receipt. The VRFD evaluation uses a randomized control experimental design that includes one treatment group and one control group. Control group members will receive a referral for services to the Division of Vocational Rehabilitation Services (DVRS), New Jersey's state Vocational Rehabilitation agency. The treatment group will receive a referral to DVRS and employment services from a resource facilitator (RF). RFs are fully integrated members of clinical teams who engage with injured workers during inpatient rehabilitation about return to work. The central research questions include:

- Was the intervention implemented as planned?
- What are key considerations for scaling up or adopting the VRF model at other facilities?
- What were the impacts of VRF on outcomes of interest?
- Did treatment group members earn or work more than control group members?
- Were treatment group members relatively less likely to apply to or receive SSI or SSDI benefits?
- Did treatment group members experience greater satisfaction and well-being than control group members?
- What were the benefits and costs of the demonstration across key groups?

The proposed public survey data collections will support three components of the planned implementation, impact, and benefit-cost analyses. The data collection efforts will provide information that is not available in SSA program records about the characteristics and outcomes of VRFD participants in the treatment and control groups. Respondents are newly injured SCI and BI patients, who will provide written consent before agreeing to participate in the study and be randomly assigned to one of the study groups.

Type of Request: Request for a new information collection.

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) *	Average wait time in field office or for teleservice centers (minutes) **	Total annual opportunity cost (dollars) ***
Informed Consent Form	500	1	10	83	* $28.01	** 21	*** $7,227
Baseline Survey	500	1	15	125	* 28.01	** 21	*** 8,403
12-month Follow-up Survey	400	1	20	133	* 28.01	** 21	*** 7,647
Staff Interviews with Site Staff	10	2	66	22	* 28.01	** 21	*** 728
Onsite Audit of sample of case files	1	2	30	1	* 28.01	** 21	*** 28
Totals	1,411			364			*** 24,033

* We based this figure on the average U.S. worker's hourly wages, as reported by Bureau of Labor Statistics data (*https://www.bls.gov/oes/current/oes_nat.htm*).
** We based this figure by averaging the average FY 2022 wait times for field offices and teleservice centers, based on SSA's current management information data.
*** This figure does not represent actual costs that SSA is imposing on recipients of Social Security payments to complete this application; rather, these are theoretical opportunity costs for the additional time respondents will spend to complete the application. *There is no actual charge to respondents to complete the application.*

2. Application for a Social Security Number Card, the Social Security Number Application Process (SSNAP), and internet SSN Replacement Card (iSSNRC) Application—20 CFR 422.103–422.110—0960–0066.

SSA collects information on the SS–5 (used in the United States) and SS–5–FS (used outside the United States) to issue original or replacement Social Security cards. SSA also enters the application data into the SSNAP application when issuing a card via telephone or in person. In addition, hospitals collect the same information on SSA's behalf for newborn children through the Enumeration-at-Birth process. In this process, parents of newborns provide hospital birth registration clerks with information required to register these newborns. Hospitals send this information to State Bureaus of Vital Statistics (BVS), and they send the information to SSA's National Computer Center. SSA then uploads the data to the SSA mainframe along with all other enumeration data, and we assign the newborn a Social Security number (SSN) and issue a Social Security card. Respondents can also use these modalities to request a change in their SSN records. In addition, the iSSNRC internet application collects information similar to the paper SS–5 for no-change, and a name change due to marriage, replacement SSN cards for adult U.S. citizens. The iSSNRC modality allows certain applicants for SSN replacement cards to complete the internet application and submit the required evidence online rather than completing a paper Form SS–5. Finally, oSSNAP collects information similar to that which we collect on the paper SS–5 for no change situations, with the exception of a name change. oSSNAP allows applicants, both U.S. citizens and non-citizens, for new or replacement SSN cards to start the application process on-line, receive a list of evidentiary documents, and then submit the application data to SSA for further processing by SSA employees. Applicants need to visit a local SSA office to complete the application process. We are planning to make minor changes to clarify that one screen is optional, and to provide a space for respondents to inform SSA of the types of documents they will present during the in-person follow up meeting. The respondents for this information collection are applicants for original and replacement Social Security cards, or individuals who wish to change information in their SSN records, who use any of the modalities described above.

Type of Request: Revision of an OMB-approved information collection.

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) *	Average wait time in field office or for teleservice centers (minutes) **	Total annual opportunity cost (dollars) ***
EAB Modality:							
Hospital staff who relay the State birth certificate information to the BVS and SSA through the EAB process	3,759,517	1	5	313,293	* $24.49	** 0	*** $7,672,546
iSSNRC Modality:							
Adult U.S. Citizens requesting a replacement card with no changes through the iSSNRC	3,002,698	1	5	250,225	* 28.01	** 0	*** 7,008,802
Adult U.S. Citizens requesting a replacement card with a name change through iSSNRC	1,312	1	5	109	* 28.01	** 0	*** 3,053
oSSNAP Modality:							
Adult U.S. Citizens providing information to receive a replacement card through the oSSNAP+	822,104	1	5	68,509	* 28.01	** 24	*** 11,129,802
Adult U.S. Citizens providing information to receive an original card through the oSSNAP+	37,323	1	5	3,110	* 28.01	* 24	*** 505,272

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) *	Average wait time in field office or for teleservice centers (minutes) **	Total annual opportunity cost (dollars) ***
Adult Non-U.S. Citizens providing information to receive a replacement card through the oSSNAP+	84,635	1	5	7,053	* 28.01	** 24	*** 1,145,805
SSNAP/SS–5 Modality:							
Respondents who do not have to provide parents' SSNs	6,973,505	1	9	1,046,026	* 28.01	** 24	**** 107,430,338
Respondents whom we ask to provide parents' SSNs (when applying for original SSN cards for children under age 12)	207,521	1	9	31,128	* 28.01	** 24	*** 3,196,949
Applicants age 12 or older who need to answer additional questions so SSA can determine whether we previously assigned an SSN	1,113,144	1	10	185,524	* 28.01	** 24	*** 17,668,204
Applicants asking for a replacement SSN card beyond the allowable limits (*i.e.,* who must provide additional documentation to accompany the application)	6,703	1	60	6,703	* 28.01	** 24	*** 262,846
Enumeration Quality Review:							
Authorization to SSA to obtain personal information cover letter	500	1	15	125	* 28.01	** 24	*** 9,103
Authorization to SSA to obtain personal information follow-up cover letter	500	1	15	125	* 28.01	** 24	*** 9,103
Grand Total: Totals	16,213,543			1,928,937			*** 159,309,973

+ The number of respondents for this modality is an estimate based on google analytics data for the SS–5 form downloads from *SSA.Gov*.
* We based this figure on average Hospital Records Clerks (*https://www.bls.gov/oes/current/oes292098.htm*), and average U.S. worker's hourly wages (*https://www.bls.gov/oes/current/oes_nat.htm*) as reported by the U.S. Bureau of Labor Statistics.
** We based this figure on the average FY 2022 wait times for field offices, based on SSA's current management information data.
*** This figure does not represent actual costs that SSA is imposing on recipients of Social Security payments to complete this application; rather, these are theoretical opportunity costs for the additional time respondents will spend to complete the application. *There is no actual charge to respondents to complete the application.*

II. SSA submitted the information collection below to OMB for clearance. Your comments regarding this information collection would be most useful if OMB and SSA receive them 30 days from the date of this publication. To be sure we consider your comments, we must receive them no later than January 30, 2023. Individuals can obtain copies of this OMB clearance package by writing to *OR.Reports.Clearance@ssa.gov*.

Advance Designation of Representative Payee—0960–0814. On April 13, 2018, the President signed into law The Strengthening Protections for Social Security Beneficiaries Act of 2018, also known as Public Law (Pub. L.) 115–165. Section 201 of the law allows SSA beneficiaries and applicants under title II, title VIII, and title XVI of the Social Security Act to designate individuals to serve as a representative payee should the need arise in the future. Section 201(j)(2) of Public Law 115–165 provides the requirements for selecting a qualified representative payee. SSA only offers the option to advance designate to capable adults and emancipated minors. Beneficiaries who have an assigned representative payee, or have a representative application in process, cannot advance designate. Form SSA–4547, Advance Designation of Representative Payee (ADRP), allows beneficiaries or applicants the option to designate individuals in order of priority, to serve as a representative. Beneficiaries or applicants can update or change the advance designee order of priority at any time. SSA uses the information on Form SSA–4547 to select a qualified representative payee in order of priority. If the selected representative payee is unable or unwilling to serve, or meet SSA requirements, SSA will select another representative payee to serve in the beneficiaries and applicant's best interest. SSA will notify beneficiaries annually of the individuals they chose in advance to be their representative payee. The respondents are SSA beneficiaries and claimants who want to choose an advance designate representative.

Type of Request: Revision of an OMB-approved information collection.

SUBMISSION OF ADVANCE DESIGNATION

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) **	Average wait time in field office (minutes) ***	Total annual opportunity cost (dollars) ****
Intranet version (Paper Form SSA–4547, SSI Claims System, MCS, iMain)	* 473,052	1	6	47,305	** $19.86	*** 24	**** $4,697,406
Internet version (mySSA)	327,101	1	6	32,710	** 19.86		**** 649,621
Internet version (iClaim)	827,257	1	6	82,726	** 19.86		**** 1,642,938

SUBMISSION OF ADVANCE DESIGNATION—Continued

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) **	Average wait time in field office (minutes) ***	Total annual opportunity cost (dollars) ****
Totals	1,627,410			162,741			**** 6,989,965

* SSA enters advance designation information we receive on the paper Form SSA–4547 in the ADRP system using one of the Intranet applications. Accordingly, we have included the paper form responses in this figure for Intranet responses.
** We based this figure by averaging both the average DI payments based on SSA's current FY 2022 data (*https://www.ssa.gov/legislation/2022factsheet.pdf*), and the average U.S. worker's hourly wages, as reported by Bureau of Labor Statistics data (*https://www.bls.gov/oes/current/oes_nat.htm*).
*** We based this figure on the average FY 2022 wait times for field offices, based on SSA's current management information data.
**** This figure does not represent actual costs that SSA is imposing on recipients of Social Security payments to complete this application; rather, these are theoretical opportunity costs for the additional time respondents will spend to complete the application. *There is no actual charge to respondents to complete the application.*

WAIVER OF ADVANCE DESIGNATION

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) **	Average wait time in field office (minutes) ***	Total annual opportunity cost (dollars) ****
Intranet version (Paper Form SSA–4547, SSI Claims System, MCS, iMain)	394,493	1	2	13,150	** $19.86	*** 24	**** $3,395,007
Internet version (mySSA)	262,996	1	2	8,767	** 19.86		**** 174,113
Internet version (iClaim)	657,489	1	2	21,916	** 19.86		**** 435,252
Totals	1,314,978			43,833			**** 4,004,372

** We based this figure by averaging both the average DI payments based on SSA's current FY 2022 data (*https://www.ssa.gov/legislation/2022factsheet.pdf*), and the average U.S. worker's hourly wages, as reported by Bureau of Labor Statistics data (*https://www.bls.gov/oes/current/oes_nat.htm*).
*** We based this figure on the average FY 2022 wait times for field offices, based on SSA's current management information data.
**** This figure does not represent actual costs that SSA is imposing on recipients of Social Security payments to complete this application; rather, these are theoretical opportunity costs for the additional time respondents will spend to complete the application. *There is no actual charge to respondents to complete the application.*

GRANT TOTALS

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)	Average theoretical hourly cost amount (dollars) **	Average wait time in field office (minutes) ***	Total annual opportunity cost (dollars) ****
Totals	2,942,388			206,574			**** $10,994,337

** We based this figure by averaging both the average DI payments based on SSA's current FY 2022 data (*https://www.ssa.gov/legislation/2022factsheet.pdf*), and the average U.S. worker's hourly wages, as reported by Bureau of Labor Statistics data (*https://www.bls.gov/oes/current/oes_nat.htm*).
*** We based this figure on the average FY 2022 wait times for field offices, based on SSA's current management information data.
**** This figure does not represent actual costs that SSA is imposing on recipients of Social Security payments to complete this application; rather, these are theoretical opportunity costs for the additional time respondents will spend to complete the application. *There is no actual charge to respondents to complete the application.*

Dated: December 27, 2022.

Naomi Sipple,

Reports Clearance Officer, Social Security Administration.

[FR Doc. 2022–28433 Filed 12–29–22; 8:45 am]

BILLING CODE 4191–02–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Notice of Availability of Adopted Final Environmental Impact Statement (EIS) and Combined Record of Decision (ROD)

AGENCY: Federal Highway Administration (FHWA), Department of Transportation (DOT).

ACTION: Notice.

SUMMARY: The FHWA, on behalf of the California Department of Transportation (Caltrans), is issuing this notice to announce Caltrans' adoption of the Maritime Administration's (MARAD) Combined Final Environmental Impact Statement/Record of Decision and Final Section 4(f) Evaluation (FEIS/ROD) for the Port of Long Beach (POLB or Port) Pier B On-Dock Rail Support Facility Project (Project).

FOR FURTHER INFORMATION CONTACT: For Caltrans District 7: Michael Enwedo, Branch Chief, Division of Environmental Planning, California Department of Transportation—District 7, 100 S Main Street, Los Angeles, CA 90012. Office Hours: 8:00 a.m.–5:00 p.m., Pacific Standard Time, telephone (213) 335–0060 or email *michael.enwedo@dot.ca.gov.* For FHWA, contact Shawn Oliver at (916) 498–5048 or email *Shawn.Oliver@dot.gov.*

SUPPLEMENTARY INFORMATION: The Final EIS and ROD for the Pier B On-Dock Rail Support Facility Project were approved by MARAD on April 7, 2022. MARAD's Notice of Availability for the Final EIS and ROD was published in the **Federal Register** on April 15, 2022. Under 49 U.S.C. 304a(b), MARAD issued a single Final EIS and ROD (USEPA, 2022). Therefore, the 30-day wait/review period under the National Environmental Policy Act (NEPA) did not apply to the action (**Federal Register**, 2022).

Pursuant to 40 CFR 1506.3(b)(2), Caltrans was a cooperating agency on this project. Therefore, recirculation of the document is not necessary under Section 1506.3(c) of the Council on Environmental Quality (CEQ) regulations.

Subsequent to MARAD's ROD issued for the entire Pier B On-Dock Rail

Support Facility Project, pursuant to 40 Code of Federal Regulations (CFR) 1505.2 and 23 CFR 771.127, Caltrans issued a ROD for the Pier B Street Freight Corridor Reconstruction Project, which is a component of the Pier B On-Dock Rail Support Facility Project. Caltrans is a cooperating agency for the Pier B On-Dock Rail Support Facility Project. This ROD is solely for Caltrans approval of the Pier B Street Freight Corridor Reconstruction Project.

The Pier B Street Freight Corridor Reconstruction Project scope includes the following:

- *Pier B Street:* Realignment of Pier B St between Pico Avenue and Anaheim Street and widening into two lanes in each direction to improve goods movement mobility and enhance pedestrian travel. The realignment of Pier B Street would require the reconstruction of two intersections, at Anaheim Way and Edison Avenue.
- *9th Street Crossing:* The existing at-grade 9th Street railroad grade crossing would be closed. After the intersection with 9th street is closed, access to Interstate 710 (I–710) would remain open at Pico Avenue, where the existing ramp at the 9th Street/Pico Avenue intersection is located. Access to Anaheim Street would be shifted to Anaheim Way and Farragut Avenue at the western end of Pier B Street.
- *Removal of Shoemaker Ramps:* The Shoemaker ramps and approaches would be removed. The Shoemaker north approach and the 9th Street bridge north approach would be demolished.
- *Pico Avenue:* Pico Avenue is located within a narrow corridor between I–710 and several buildings, terminals, and ramps. Pico Avenue would be realigned to the west from Pier B St/I–710 ramps south to approximately Pier D Street to accommodate the addition of railroad tracks. The existing at-grade crossing at Pico Avenue/Pier D Street would be closed.
- *Sidewalk:* The construction of new sidewalk on the south side of Pier B St and along the west 7 side of Pico Ave.

Dated: December 23, 2022.

Vincent P. Mammano,

Division Administrator, Federal Highway Administration, California Division.

[FR Doc. 2022–28424 Filed 12–29–22; 8:45 am]

BILLING CODE 4910–RY–P

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

Notice of OFAC Sanctions Actions

AGENCY: Office of Foreign Assets Control, Treasury.

ACTION: Notice.

SUMMARY: The U.S. Department of the Treasury's Office of Foreign Assets Control (OFAC) is publishing the names of one or more persons that have been removed from OFAC's Specially Designated Nationals and Blocked Persons List (SDN List) and the List of Foreign Sanctions Evaders (FSE List). Their property and interests in property are no longer blocked, and U.S. persons are no longer generally prohibited from engaging in transactions with them.

DATES: See **SUPPLEMENTARY INFORMATION** section for applicable date(s).

FOR FURTHER INFORMATION CONTACT: *OFAC:* Andrea Gacki, Director, tel.: 202–622–2480; Associate Director for Global Targeting, tel: 202–622–2420; Assistant Director for Licensing, tel.: 202–622–2480; Assistant Director for Regulatory Affairs, tel.: 202–622–4855; or the Assistant Director for Sanctions Compliance & Evaluation, tel.: 202–622–2490.

SUPPLEMENTARY INFORMATION:

Electronic Availability

The SDN List and additional information concerning OFAC sanctions programs are available on OFAC's website (*www.treasury.gov/ofac*).

Notice of OFAC Actions

On December 12, 2022, OFAC determined that the following persons, who had been designated pursuant to Executive Order 13582 of August 17, 2011, ''Blocking Property of the Government of Syria and Prohibiting Certain Transactions With Respect to Syria'' and sanctioned pursuant to Executive Order 13608 of May 1, 2012 ''Prohibiting Certain Transactions With and Suspending Entry Into the United States of Foreign Sanctions Evaders With Respect to Iran and Syria, '' should be removed from the SDN List and FSE List, and that the property and interests in property subject to U.S. jurisdiction of the following persons are unblocked and lawful transactions involving U.S. persons are no longer prohibited.

Entity

1. RIXO INTERNATIONAL TRADING LTD., Lindenstrasse 2, Baar 6340, Switzerland; website *http://www.rixo international.com* [SYRIA] [FSE–SY].

Individual

1. BEKTAS, Halis; DOB 13 Feb 1966; citizen Switzerland; Passport X0906223 (Switzerland) (individual) [SYRIA] [FSE–SY].

Dated: December 12, 2022.

Andrea M. Gacki,

Director, Office of Foreign Assets Control, U.S. Department of the Treasury.

[FR Doc. 2022–28440 Filed 12–29–22; 8:45 am]

BILLING CODE 4810–AL–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Requesting Comments on Form 8936, Qualified Plug-in Electric Drive Motor Vehicle Credit and Revenue Procedure 2022–42

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Internal Revenue Service, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on continuing information collections, as required by the Paperwork Reduction Act of 1995. The IRS is soliciting comments concerning qualified plug-in electric vehicle credit and Revenue Procedure 2022–42.

DATES: Written comments should be received on or before February 28, 2023 to be assured of consideration.

ADDRESSES: Direct all written comments to Andres Garcia, Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224, or by email to *pra.comments@irs.gov.* Include OMB Control No. 1545–2137 in the subject line of the message.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of this collection should be directed to Andres Garcia, (202) 317–4542, at Internal Revenue Service, Room 6526, 1111 Constitution Avenue NW, Washington, DC 20224, or through the internet at *andres.garcia@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Qualified Plug-in Electric Vehicle Credit and Rev. Proc 2022–46.

OMB Number: 1545–2137.

Form Number: 8936, 8936–A and Schedule 1 (Form 8936–A).

Abstract: For tax years beginning after 2008, Form 8936 is used to figure the credit for qualified plug-in electric drive motor vehicles placed in service during the tax year. The credit attributable to depreciable property (vehicles used for business or investment purposes) is treated as a general business credit. Any credit not attributable to depreciable property is treated as a personal credit. For tax year beginning after 2022, Form 8936–A and Schedule 1 (Form 8936–A) are used to figure the Qualified Commercial Clean Vehicle Credit. Notice 2009–54 sets forth guidance relating to the qualified plug-in electric drive motor vehicle credit under section 30D of the Internal Revenue Code, as in effect for vehicles acquired after December 31, 2009. Revenue Procedure 2022–42 (Rev. Proc. 2022–42) provides procedures for a vehicle manufacturer to certify that they are a qualified manufacturer of such vehicles and submit reports that a motor vehicle meets certain requirements for the clean vehicle credit(s) available under sections 30D, 45W, and/or 25E, to report the amount of the credit available with respect to the motor vehicle, and for sellers to report the sales of such vehicles.

Current Actions: There are no changes being made to the collection. IRS is seeking approval to extend the OMB expiration date.

Type of Review: Extension of a currently approved collection.

Affected Public: Individual, businesses, and other for-profit organizations.

Form 8936:

Estimated Number of Respondents: 500.

Estimated Number of Responses: 500.

Estimated Time per Response: 7 hours.

Estimated Total Annual Burden Hours: 35,000.

Form 8936–A and Schedule 1 (Form 8936–A):

Estimated Number of Respondents: 129.

Estimated Number of Responses: 129.

Estimated Time per Response: 2.90 hours.

Estimated Total Annual Burden Hours: 374 hours.

Notice 2009–89:

Estimated Number of Respondents: 12.

Estimated Number of Responses: 12.

Estimated Time Per Response: 23.33 hours.

Estimated Total Annual Burden Hours: 280 hours.

Rev. Proc. 2022–42, annual reports:

Estimated Number of Respondents: 52,165. Estimated Number of Responses: 52,165.

Estimated Time per Response: 15 minutes.

Estimated Total Annual Burden Hours: 13,041 hours.

Rev. Proc. 2022–42, monthly reports:

Estimated Number of Respondents: 150.

Estimated Number of Responses: 1,800.

Estimated Time per Response: 15 minutes.

Estimated Total Annual Burden Hours: 450 hours.

The following paragraph applies to all of the collections of information covered by this notice.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: December 23, 2022.

Andres Garcia Leon,

Supervisory Tax Analyst.

[FR Doc. 2022–28402 Filed 12–29–22; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Superfund Chemical Substance Tax; Request To Modify List of Taxable Substances; Filing of Petition for Polyphenylene Sulfide

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of filing and request for comments.

SUMMARY: This notice of filing announces that a petition has been filed pursuant to Revenue Procedure 2022–26, 2022–29 I.R.B. 90, requesting that polyphenylene sulfide be added to the list of taxable substances under section 4672(a) of the Internal Revenue Code. This notice of filing also requests comments on the petition. This notice of filing is not a determination that the list of taxable substances is modified.

DATES: Written comments and requests for a public hearing must be received on or before February 28, 2023.

ADDRESSES: Commenters are encouraged to submit public comments or requests for a public hearing relating to this petition electronically via the Federal eRulemaking Portal at *http://www.regulations.gov* (indicate public docket number IRS–2022–0037 or polyphenylene sulfide) by following the online instructions for submitting comments. Comments cannot be edited or withdrawn once submitted to the Federal eRulemaking Portal. Alternatively, comments and requests for a public hearing may be mailed to: Internal Revenue Service, Attn: CC:PA:LPD:PR (Notice of Filing for Polyphenylene Sulfide), Room 5203, P.O. Box 7604, Ben Franklin Station, Washington, DC 20044. All comments received are part of the public record and subject to public disclosure. All comments received will be posted without change to *www.regulations.gov,* including any personal information provided. You should submit only information that you wish to make publicly available. If a public hearing is scheduled, notice of the time and place for the hearing will be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Please contact Amanda F. Dunlap, (202) 317–6855 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

(a) *Overview.* The petition requesting the addition of polyphenylene sulfide to the list of taxable substances under section 4672(a) of the Internal Revenue Code contains the information detailed in paragraph (b) of this document. The information is provided for public notice and comment pursuant to section 9 of Rev. Proc. 2022–26. The publication of petition content in this notice of filing does not constitute Department of the Treasury or Internal Revenue Service confirmation of the accuracy of the information published.

(b) *Petition Content.*

(1) *Substance name:* Polyphenylene sulfide.

According to the petition, these are the commonly used substance names for polyphenylene sulfide:

Polyphenylene sulfide
PPS
Poly(p-phenylenesulfide)
Benzene, 1,4-dichloro-, polymer with sodium sulfide

(2) *Petitioner:* Celanese Ltd., an exporter of polyphenylene sulfide.

(3) *Proposed Classification Numbers:*
HTSUS number: 3911.90.2500
Schedule B number: 3911.90.6100
CAS numbers: 25212–74–2, 26125–40–6

(4) *Petition Filing Date:* December 20, 2022.

Petition filing date for purposes of section 11.02 of Rev. Proc. 2022–26: July 1, 2022.

(5) *Brief Description of the Petition:* According to the petition, polyphenylene sulfide is a high-performance thermoplastic, has high heat and chemical resistance, and is used in applications such as filters, appliance, machine and automobile parts, replacing steel in some cases.

In the final step, polyphenylene sulfide is manufactured by the polymerization of 1,4-dichlorobenzene (p-DCB), a taxable substance, with sodium hydrosulfide and sodium hydroxide. Sodium hydrosulfide is made from sodium hydroxide and hydrogen sulfide. Taxable chemicals constitute 90.0 percent by weight of the materials used to produce this substance.

(6) *Process Identified in Petition as Predominant Method of Production of Substance:*

Three separate reactions:

(A) 1,4 dichlorobenzene is made from the reaction of benzene with 2 equivalents of chlorine.

(B) Sodium hydrogen sulfide is made from the reaction of hydrogen sulfide with sodium hydroxide.

(C) 1,4-dichlorobenzene (p-dichlorobenzene, p-DCB), sodium hydrosulfide (NaSH), and sodium hydroxide (NaOH) are reacted at high temperature and high pressure to form polyphenylene sulfide and byproduct sodium chloride.

(7) *Stoichiometric Material Consumption Equation, Based on Process Identified as Predominant Method of Production:*

$n\ [2\ NaOH + C_6H_6 + 2\ Cl_2 + H_2S\ ] \rightarrow [\text{phenylene sulfide}]_n + 2n\ H_2O + 2n\ NaCl$

(8) *Rate of Tax Calculated by Petitioner Based on Petitioner's Conversion Factors for Taxable Chemicals Used in Production of Substance:* Rate of Tax: $14.50 per ton.

Conversion Factors:

0.74 for sodium hydroxide
0.72 for benzene
1.31 for chlorine

(9) *Public Docket Number:* IRS–2022–0037.

Stephanie Bland,
Branch Chief (Passthroughs and Special Industries), IRS Office of Chief Counsel.

[FR Doc. 2022–28407 Filed 12–29–22; 8:45 am]

BILLING CODE 4830–01–P

FEDERAL REGISTER

Vol. 87 Friday,

No. 250 December 30, 2022

Part II

Environmental Protection Agency

40 CFR Parts 80 and 1090

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

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

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.

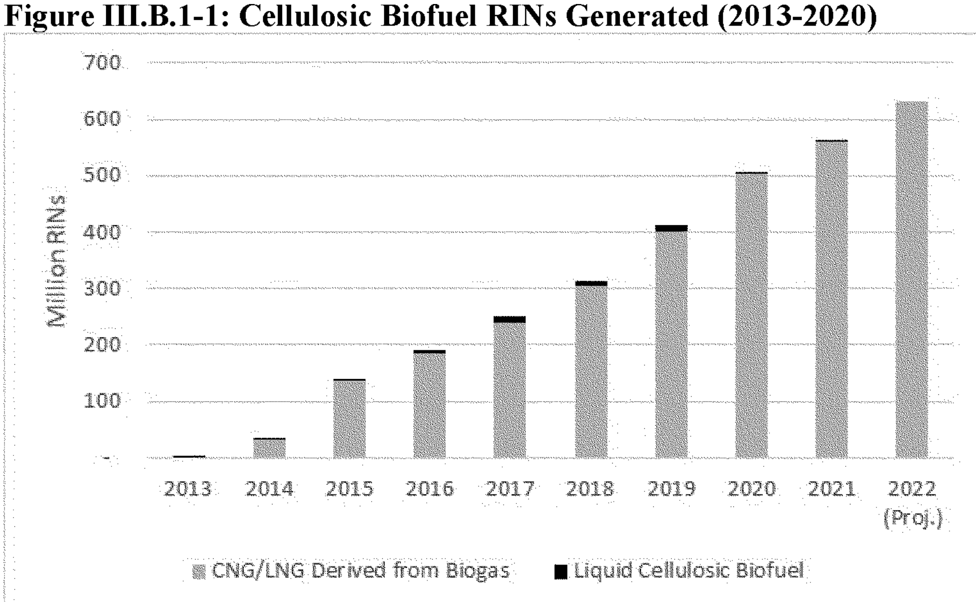
Nevertheless, in our assessment of renewable fuel supply, we have also made projections for one additional year, 2026. As discussed more fully in Section VI.F, we believe that 2026 represents a transitional year in the market's response to the availability of eRINs. Prior to 2026, we expect eRIN generators 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

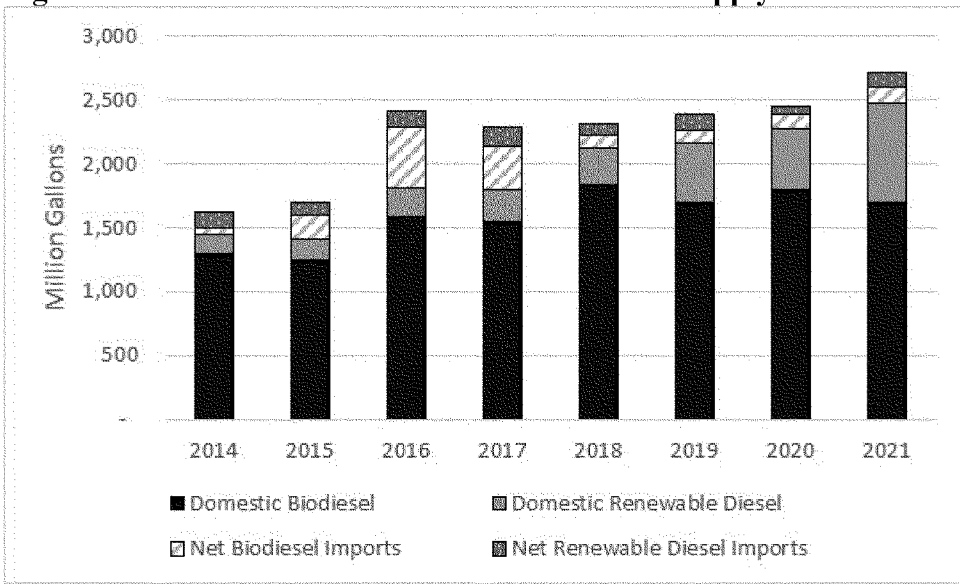
For the 2023–2025 timeframe, we expect that commercial scale production of cellulosic biofuel in the U.S. will be limited to electricity and CNG/LNG derived from biogas. In previous years several foreign cellulosic biofuel facilities have also supplied ethanol produced from sugarcane bagasse and heating 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.

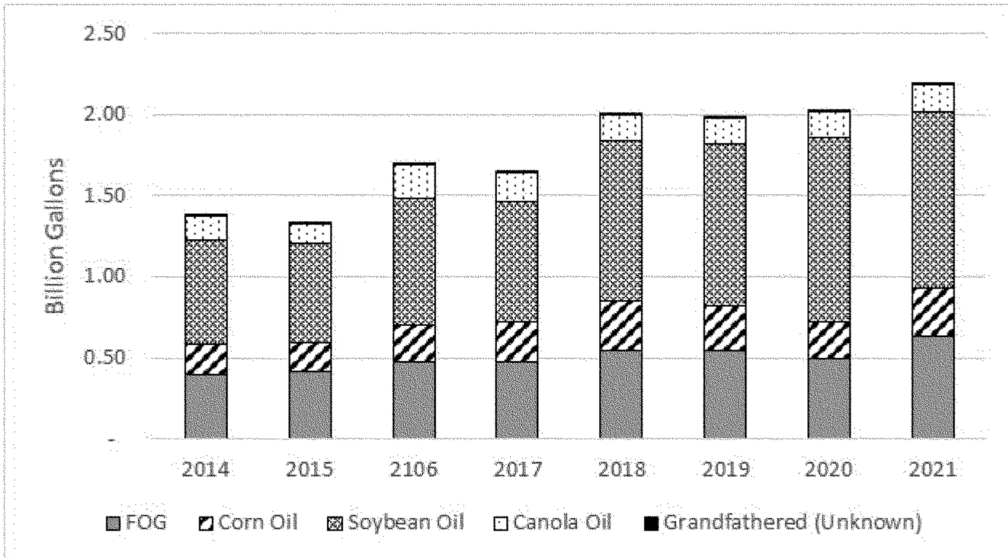
[64] In 2021 nearly all renewable diesel consumed in the U.S. was consumed in California. Together renewable diesel and biodiesel represented approximately 26 percent of all diesel fuel consumed in California in 2021.

[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

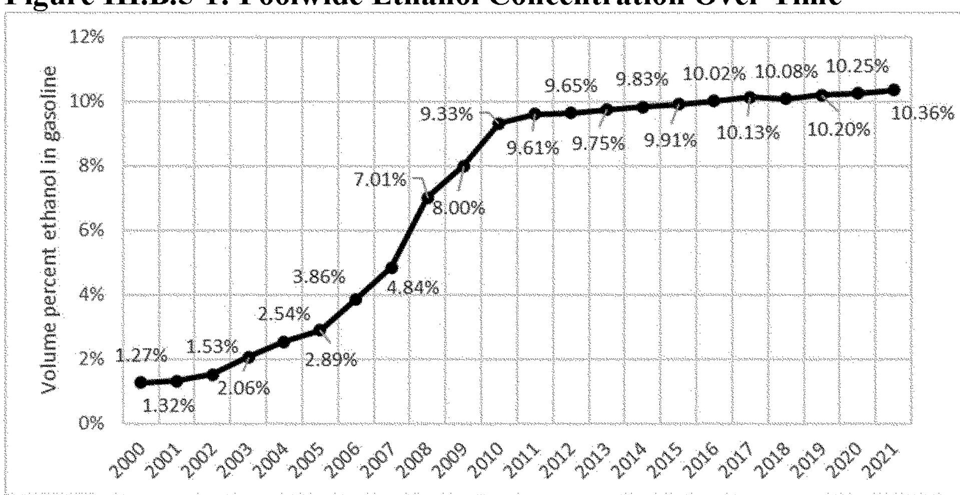
U.S. could be an attractive market for this foreign-produced conventional biodiesel and renewable diesel if domestic demand for conventional renewable fuel exceeded domestic supply, *i.e.,* the amount of ethanol that could be consumed combined with domestic production of conventional biodiesel and renewable 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

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

[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.

[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

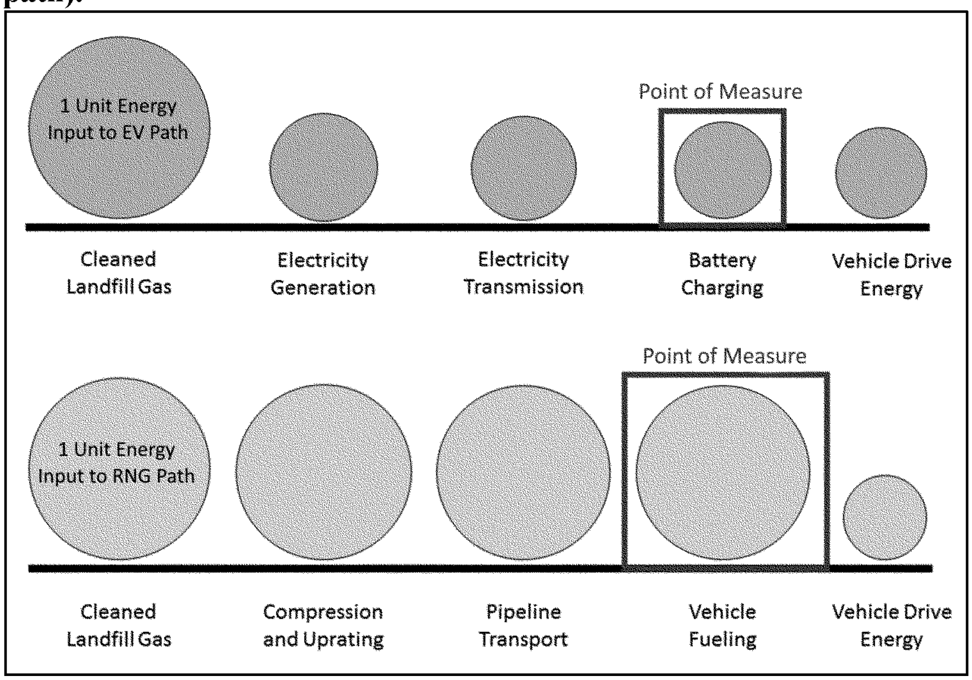
[277] See 40 CFR 80.1415.

[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).



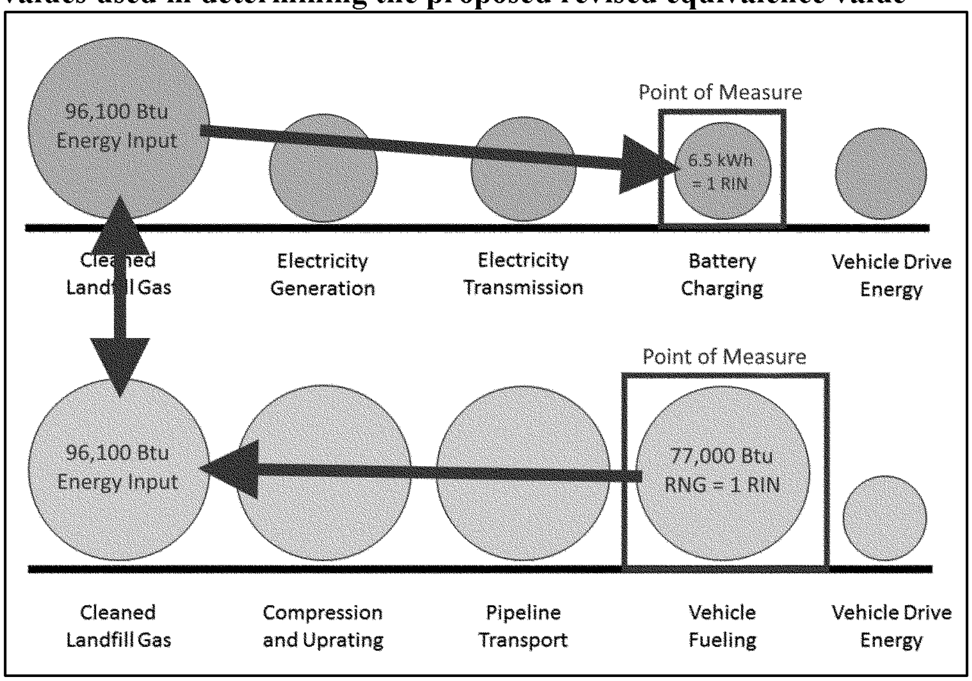
As the diagram makes clear, this POM produces a very different measure of fuel energy for electricity than for RNG. In the case of electricity, the initial conversion of the biogas's chemical energy to mechanical energy occurs upstream of the POM in the EGU, and this step results in a significant loss 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.

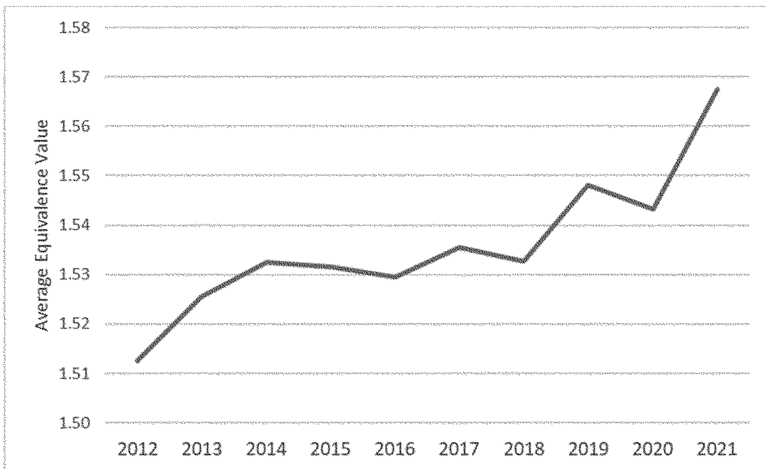
RDS_i = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory, in year i, if the state or territory opts-in, in gallons.

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, hemicellulose, 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

§ 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''.

[FR Doc. 2022–26499 Filed 12–29–22; 8:45 am]

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H.R. 203/P.L. 117–265

To designate the facility of the United States Postal Service located at 4020 Broadway Street in Houston, Texas, as the "Benny C. Martinez Post Office Building". (Dec. 27, 2022; 136 Stat. 4170)

H.R. 441/P.L. 117–266

Don Young Alaska Native Health Care Land Transfers Act of 2022 (Dec. 27, 2022; 136 Stat. 4171)

H.R. 478/P.L. 117–267

Blackwater Trading Post Land Transfer Act (Dec. 27, 2022; 136 Stat. 4174)

H.R. 1095/P.L. 117–268

To designate the facility of the United States Postal Service located at 101 South Willowbrook Avenue in Compton, California, as the "PFC James Anderson, Jr., Post Office Building". (Dec. 27, 2022; 136 Stat. 4176)

H.R. 2472/P.L. 117–269

To designate the facility of the United States Postal Service located at 82422 Cadiz Jewett Road in Cadiz, Ohio, as the "John Armor Bingham Post Office". (Dec. 27, 2022; 136 Stat. 4177)

H.R. 2473/P.L. 117–270

To designate the facility of the United States Postal Service located at 275 Penn Avenue in Salem, Ohio, as the "Howard Arthur Tibbs Post Office". (Dec. 27, 2022; 136 Stat. 4178)

H.R. 2724/P.L. 117–271

To amend title 38, United States Code, to direct the Secretary of Veterans Affairs to provide for peer support specialists for claimants who are survivors of military sexual trauma, and for other purposes. (Dec. 27, 2022; 136 Stat. 4179)

H.R. 3285/P.L. 117–272

21st Century President Act (Dec. 27, 2022; 136 Stat. 4181)

H.R. 4250/P.L. 117–273

War Crimes Rewards Expansion Act (Dec. 27, 2022; 136 Stat. 4182)

H.R. 4622/P.L. 117–274

To designate the facility of the United States Postal Service located at 226 North Main Street in Roseville, Ohio, as the "Ronald E. Rosser Post Office". (Dec. 27, 2022; 136 Stat. 4183)

H.R. 4881/P.L. 117–275

Old Pascua Community Land Acquisition Act (Dec. 27, 2022; 136 Stat. 4184)

H.R. 4899/P.L. 117–

76 To designate the facility of the United States Postal Service located at 10 Broadway Street West, in Akeley, Minnesota, as the "Neal Kenneth Todd Post Office". (Dec. 27, 2022; 136 Stat. 4186)

H.R. 5271/P.L. 117–277

To designate the facility of the United States Postal Service located at 2245 Rosa L Parks Boulevard in Nashville, Tennessee, as the "Thelma Harper Post Office Building". (Dec. 27, 2022; 136 Stat. 4187)

H.R. 5349/P.L. 117–278

To designate the facility of the United States Postal Service located at 1550 State Road S-38-211 in Orangeburg, South Carolina, as the "J.I. Washington Post Office Building". (Dec. 27, 2022; 136 Stat. 4188)

H.R. 5650/P.L. 117–279

To designate the facility of the United States Postal Service located at 16605 East Avenue of the Fountains in Fountain Hills, Arizona, as the "Dr. C.T. Wright Post Office Building". (Dec. 27, 2022; 136 Stat. 4189)

H.R. 5659/P.L. 117–280

To designate the facility of the United States Postal Service located at 1961 North C Street in Oxnard, California, as the "John R. Hatcher III Post Office Building". (Dec. 27, 2022; 136 Stat. 4190)

H.R. 5794/P.L. 117–281

To designate the facility of the United States Postal Service located at 850 Walnut Street in McKeesport, Pennsylvania, as the "First Sergeant Leonard A. Funk, Jr. Post Office Building". (Dec. 27, 2022; 136 Stat. 4191)

H.R. 5865/P.L. 117–282

To designate the facility of the United States Postal Service located at 4110 Bluebonnet Drive in Stafford, Texas, as the "Leonard Scarcella Post Office Building". (Dec. 27, 2022; 136 Stat. 4192)

H.R. 5900/P.L. 117–283

To designate the facility of the United States Postal Service located at 2016 East 1st Street in Los Angeles, California, as the "Marine Corps Reserve PVT Jacob Cruz Post Office". (Dec. 27, 2022; 136 Stat. 4193)

H.R. 5943/P.L. 117–284

To designate the outpatient clinic of the Department of Veterans Affairs in Greenville, South Carolina, as the "Lance Corporal Dana Cornell Darnell VA Clinic". (Dec. 27, 2022; 136 Stat. 4194)

H.R. 5952/P.L. 117–285

To designate the facility of the United States Postal Service located at 123 East Main Street, in Vergas, Minnesota, as the "Jon Glawe Post Office". (Dec. 27, 2022; 136 Stat. 4195)

H.R. 5961/P.L. 117–286

To make revisions in title 5, United States Code, as necessary to keep the title current, and to make technical amendments to improve the United States Code. (Dec. 27, 2022; 136 Stat. 4196)

H.R. 5973/P.L. 117–287

Great Lakes Fish and Wildlife Restoration Reauthorization Act of 2022 (Dec. 27, 2022; 136 Stat. 4363)

H.R. 6042/P.L. 117–288

To designate the facility of the United States Postal Service located at 213 William Hilton Parkway in Hilton Head Island, South Carolina, as the "Caesar H. Wright Jr. Post Office Building". (Dec. 27, 2022; 136 Stat. 4365)

H.R. 6064/P.L. 117–289

To direct the Secretary of Veterans Affairs to seek to enter into an agreement with the National Academies of Sciences, Engineering, and Medicine for a review of examinations, furnished by the Secretary, to individuals who submit claims to the Secretary for compensation under chapter 11 of title 38, United States Code, for mental and physical conditions linked to military sexual trauma. (Dec. 27, 2022; 136 Stat. 4366)

H.R. 6080/P.L. 117–290

To designate the facility of the United States Postal Service located at 5420 Kavanaugh Boulevard in Little Rock, Arkansas, as the "Ronald A. Robinson Post Office". (Dec. 27, 2022; 136 Stat. 4368)

H.R. 6218/P.L. 117–291

To designate the facility of the United States Postal Service located at 317 Blattner Drive in Avon, Minnesota, as the "W.O.C. Kort Miller Plantenberg Post Office". (Dec. 27, 2022; 136 Stat. 4369)

H.R. 6220/P.L. 117–292

To designate the facility of the United States Postal Service located at 100 3rd Avenue Northwest in Perham, Minnesota, as the "Charles P. Nord Post Office". (Dec. 27, 2022; 136 Stat. 4370)

H.R. 6221/P.L. 117–293

To designate the facility of the United States Postal Service located at 155 Main Avenue West in Winsted, Minnesota, as the "James A. Rogers Jr. Post Office". (Dec. 27, 2022; 136 Stat. 4371)

H.R. 6267/P.L. 117–294

To designate the facility of the United States Postal Service located at 15 Chestnut Street in Suffern, New York, as the "Sergeant Gerald T. 'Jerry' Donnellan Post Office". (Dec. 27, 2022; 136 Stat. 4372)

H.R. 6386/P.L. 117–295

To designate the facility of the United States Postal Service located at 450 West Schaumburg Road in Schaumburg, Illinois, as the "Veterans of Iraq and Afghanistan Memorial Post Office Building". (Dec. 27, 2022; 136 Stat. 4373)

H.R. 6427/P.L. 117–296

Red River National Wildlife Refuge Boundary Modification Act (Dec. 27, 2022; 136 Stat. 4374)

H.R. 6604/P.L. 117–297

Veterans Eligible to Transfer School (VETS) Credit Act (Dec. 27, 2022; 136 Stat. 4375)

H.R. 6630/P.L. 117–298

To designate the facility of the United States Postal Service located at 1400 N Kraemer Blvd. in Placentia, California, as the ''PFC Jang Ho Kim Post Office Building''. (Dec. 27, 2022; 136 Stat. 4377)

H.R. 6917/P.L. 117–299
To designate the facility of the United States Postal Service located at 301 East Congress Parkway in Crystal Lake, Illinois, as the ''Ryan J. Cummings Post Office Building''. (Dec. 27, 2022; 136 Stat. 4378)

H.R. 6961/P.L. 117–300
To amend title 38, United States Code, to improve hearings before the Board of Veterans' Appeals regarding claims involving military sexual trauma. (Dec. 27, 2022; 136 Stat. 4379)

H.R. 7181/P.L. 117–301
Human Trafficking Prevention Act of 2022 (Dec. 27, 2022; 136 Stat. 4382)

H.R. 7299/P.L. 117–302
Strengthening VA Cybersecurity Act of 2022 (Dec. 27, 2022; 136 Stat. 4384)

H.R. 7335/P.L. 117–303
MST Claims Coordination Act (Dec. 27, 2022; 136 Stat. 4387)

H.R. 7514/P.L. 117–304
To designate the facility of the United States Postal Service located at 345 South Main Street in Butler, Pennsylvania, as the ''Andrew Gomer Williams Post Office Building''. (Dec. 27, 2022; 136 Stat. 4389)

H.R. 7518/P.L. 117–305
To designate the facility of the United States Postal Service located at 23200 John R Road in Hazel Park, Michigan, as the ''Roy E. Dickens Post Office''. (Dec. 27, 2022; 136 Stat. 4390)

H.R. 7519/P.L. 117–306
To designate the facility of the United States Postal Service located at 2050 South Boulevard in Bloomfield Township, Michigan, as the ''Dr. Ezra S. Parke Post Office Building''. (Dec. 27, 2022; 136 Stat. 4391)

H.R. 7638/P.L. 117–307
To designate the facility of the United States Postal Service located at 6000 South Florida Avenue in Lakeland, Florida, as the ''U.S. Marine Corporal Ronald R. Payne Jr. Post Office''. (Dec. 27, 2022; 136 Stat. 4392)

H.R. 7735/P.L. 117–308
Improving Access to the VA Home Loan Benefit Act of 2022 (Dec. 27, 2022; 136 Stat. 4393)

H.R. 8025/P.L. 117–309
To designate the facility of the United States Postal Service located at 100 South 1st Street in Minneapolis, Minnesota, as the ''Martin Olav Sabo Post Office''. (Dec. 27, 2022; 136 Stat. 4395)

H.R. 8026/P.L. 117–310
To designate the facility of the United States Postal Service located at 825 West 65th Street in Minneapolis, Minnesota, as the ''Charles W. Lindberg Post Office''. (Dec. 27, 2022; 136 Stat. 4396)

H.R. 8203/P.L. 117–311
To designate the facility of the United States Postal Service located at 651 Business Interstate Highway 35 North Suite 420 in New Braunfels, Texas, as the ''Bob Krueger Post Office''. (Dec. 27, 2022; 136 Stat. 4397)

H.R. 8226/P.L. 117–312
To designate the facility of the United States Postal Service located at 236 Concord Exchange North in South Saint Paul, Minnesota, as the ''Officer Leo Pavlak Post Office Building''. (Dec. 27, 2022; 136 Stat. 4398)

H.R. 8260/P.L. 117–313
Faster Payments to Veterans' Survivors Act of 2022 (Dec. 27, 2022; 136 Stat. 4399)

H.R. 9308/P.L. 117–314
To designate the facility of the United States Postal Service located at 6401 El Cajon Boulevard in San Diego, California, as the ''Susan A. Davis Post Office''. (Dec. 27, 2022; 136 Stat. 4403)

S. 7/P.L. 117–
15 VAWA Technical Amendment Act of 2022 (Dec. 27, 2022; 136 Stat. 4404)

S. 558/P.L. 117–316
Flood Level Observation, Operations, and Decision Support Act (Dec. 27, 2022; 136 Stat. 4406)

S. 789/P.L. 117–317
Repealing Existing Substandard Provisions Encouraging Conciliation with Tribes Act (Dec. 27, 2022; 136 Stat. 4419)

S. 1466/P.L. 117–318
Saline Lake Ecosystems in the Great Basin States Program Act of 2022 (Dec. 27, 2022; 136 Stat. 4421)

S. 1687/P.L. 117–319
Small Business Cyber Training Act of 2022 (Dec. 27, 2022; 136 Stat. 4424)

S. 2607/P.L. 117–320
Iran Hostages Congressional Gold Medal Act (Dec. 27, 2022; 136 Stat. 4426)

S. 2899/P.L. 117–321
Prison Camera Reform Act of 2021 (Dec. 27, 2022; 136 Stat. 4430)

S. 2991/P.L. 117–322
Countering Human Trafficking Act of 2021 (Dec. 27, 2022; 136 Stat. 4433)

S. 3846/P.L. 117–323
Justice and Mental Health Collaboration Reauthorization Act of 2022 (Dec. 27, 2022; 136 Stat. 4437)

S. 3905/P.L. 117–324
Preventing Organizational Conflicts of Interest in Federal Acquisition Act (Dec. 27, 2022; 136 Stat. 4439)

S. 4003/P.L. 117–325
Law Enforcement De-Escalation Training Act of 2022 (Dec. 27, 2022; 136 Stat. 4441)

S. 5229/P.L. 117–326
To direct the Joint Committee of Congress on the Library to remove the bust of Roger Brooke Taney in the Old Supreme Court Chamber of the Capitol and to obtain a bust of Thurgood Marshall for installation in the Capitol or on the Capitol Grounds, and for other purposes. (Dec. 27, 2022; 136 Stat. 4452)

S. 5230/P.L. 117–327
Billy's Law (Dec. 27, 2022; 136 Stat. 4454)

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