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DEPARTMENT OF AGRICULTURE

Rural Utilities Service

7 CFR Parts 1709, 1719, 1734, 1738, 1739, 1770, and 1773

[Docket No. RUS-22-AGENCY-0053]

RIN 0572-AC61

Policy on Audits of RUS Awardees

AGENCY: Rural Utilities Service, USDA.

ACTION: Final rule; confirmation and response to comments.

SUMMARY: The Rural Utilities Service (RUS or Agency), an agency in the United States Department of Agriculture (USDA) Rural Development Mission area, published a final rule with comment in the **Federal Register** on February 6, 2023, to revise its Policy on Audits to change the title, remove an unnecessary report, update terminology, clarify Agency contacts and filing requirements, and update or remove any outdated references. The document also made conforming changes to other regulations. These changes provide uniformity and consistency for all RUS awardees. Through this action, RUS is confirming the final rule as it was published and providing responses to the public comments that were received.

DATES: The final rule published February 6, 2023, at 88 FR 7557, is confirmed as of May 8, 2023.

FOR FURTHER INFORMATION CONTACT: Jurlme Grey, Chief, Technical Accounting Review Branch, External Compliance Division, Rural Development, U.S. Department of Agriculture, 1400 Independence Avenue SW, Washington, DC 20250, Telephone: (202) 540-9200, Email: compliance.tarb@usda.gov.

SUPPLEMENTARY INFORMATION: Rural Development is a mission area within the USDA comprising RUS, Rural Housing Service, and Rural Business-Cooperative Service. Rural Development's mission is to increase

economic opportunity and improve the quality of life for all rural Americans. The mission is met by providing loans, loan guarantees, grants, and technical assistance through numerous programs aimed at creating and improving housing, business, and infrastructure throughout rural America.

The final rule that published February 6, 2023 (88 FR 7557), included a 60-day comment period that ended on April 7, 2023. The intent of the changes outlined in the final rule are to update regulations, clarify audit policy, and streamline procedures. The uniformity and consistency for all awardees should benefit both the awardees and Agency. Professional standards and guidance provide a framework for conducting high quality audits.

The Agency received comments from 3 respondents. The following are the comments received and the Agency's responses:

Respondent One: Aurélien Enthoven.

Comment: The "Policy on Audits of Awardees" should address the disparate impact of the RUS on Native American Tribe borrowers.

Agency response: We disagree. This policy is specific to RUS Awardees who *do not* meet the requirements of non-Federal entities subject to 2 CFR part 200, subpart F. Per 2 CFR 200.1, the definition of non-Federal entity is a State, local government, Indian tribe, Institution of Higher Education (IHE), or nonprofit organization that carries out a Federal award as a recipient or subrecipient.

Respondent Two: Eide Bailly, CPAs and Business Advisors.

Comment (1): We believe that revising 7 CFR 1773.3(e) to read as follows would further clarify RUS's audit requirements for nonprofit organizations: "Subpart F of 2 CFR part 200 shall apply to audits of RUS electric and telecommunications cooperatives and for-profit telecommunications awardees only if the awardee has expenditures of federal awards from Federal agencies other than the Department of Agriculture RUS and has contractually agreed with another Federal agency (e.g., Federal Emergency Management Agency) to provide a financial audit performed in accordance with 2 CFR part 200, subpart F. If the awardee has expenditures of federal awards from Federal agencies other than the Department of Agriculture RUS, all

applicable Department of Agriculture RUS expenditures shall be included in the audit performed in accordance with 2 CFR part 200, subpart F."

Agency response (1): We disagree with the comment. This policy is specific to all RUS electric and telecommunication Awardees, which are defined as entities that have an outstanding RUS or Federal Financing Bank (FFB) loan or loan guarantee and/or a continuing responsibility under a grant agreement with RUS. The language in § 1773.3(e) uses language to clarify when the audit should not be in accordance with 2 CFR part 200, subpart F. We believe the current language in § 1773.3(e) is sufficient as it relates specifically to RUS electric and telecommunications awardees only.

Comment (2): The requirement in 1709.21(a), 1719.13(b), 1734.8(a), 1738.254(b)(1), and 1739.20(a) conflict with other guidance because it requires all nonprofit organizations to obtain a Uniform Guidance audit in accordance with 2 CFR 200 Subpart F; however, it appears that RUS's updates intend to impose a Uniform Guidance audit requirement on a nonprofit organization receiving RUS funding only when the nonprofit organization has received other Federal awards that would require the performance of the audit in accordance with 2 CFR 200 Subpart F.

Agency response (2): We disagree with the comment. We do not believe this language creates a conflict, as the primary language in §§ 1709.21(a), 1719.13(b)(1), 1734.8(a), 1738.254(b)(1), and 1739.20(a) states that if the awardee (*borrower, grantee, or recipient*) is a for-profit entity, an electric or telecommunications cooperative, or any other entity *not covered by paragraph (b) (paragraph (b)(2))*, the recipient shall provide an independent audit report in accordance with 7 CFR part 1773.

And paragraph (b) (paragraph (b)(2)) states that if the awardee (*borrower, grantee, or recipient*) is a non-Federal entity, as defined in 2 CFR 200.1, the awardee shall provide an audit in accordance with subpart F of 2 CFR part 200.

The Agency believes this language is sufficient.

Respondent Three: American Institute of CPAs (AICPA). This respondent provided a detailed response with the following items highlighted as their overarching comments:

Comment (1): (1) Clarify what the effective date means for borrowers.

Agency response (1): Thank you for pointing this out. We will provide additional guidance on the website to assist in explaining the effective date. In addition, RUS will notify current awardees of the revisions to this part.

Comment (2): RUS should be aware that the Government Accountability Office has issued an Exposure Draft that proposes changes to the Government Auditing Standards (GAS).

Agency response (2): The Agency acknowledges that the standards are being revised and will review those changes, when available, to see what changes that may entail. However, the desire is not to hold these needed revisions up until such time as updates are done and have been analyzed to determine what changes RUS needs to make.

Comment (3): Paragraphs 1773.9 and 1773.32 include details about the GAS that fail to accurately reflect the requirements and mischaracterize that the results of an audit are an opinion of the effectiveness of internal controls and the role of the audit.

Agency response (3): RUS agrees to amend the language in §§ 1773.9(b) and 1773.32(a) introductory text and (a)(2) and (3) with the next revision. This language was in the current version and has not been changed or amended with this revision. RUS disagrees with the suggested removal of § 1773.32(a)(4) and believes the current language is sufficient.

Comment (4): Other sections of 1773 are overly prescriptive. (a) Part 1773.40 seems to require that audit documentation evidence that *all* regulatory assets and liabilities be tested for compliance which implies that sampling is not acceptable. That is not consistent with standard auditing procedures. (b) Similar issues exist in Parts 1773.42 and 1773.45.

Agency response (4): Sections 1773.40 and 1773.45 were not amended thru this final rule and therefore, these sections were not open for public comment. Sections 1773.40 and 1773.45 apply to all RUS Electric and Telecom awardees, stating they must follow Financial Accounting Standards Board (FASB) requirements. Electric awardees have additional requirements to receive RUS approval for all regulatory assets or liabilities. Section 1773.42 was amended to remove all contents and reserve the section.

Comment (5): The amendment to Parts 1719.13(b)(1) and 1738.254 includes an incorrect reference to 1773.5 and should be 1773.4.

Agency response (5): RUS agrees. The reference in §§ 1719.13(b) and 1738.254(b) will be amended to § 1773.4 in the next revision. RUS does not consider this a significant deviation because while § 1773.4 addresses RUS approval of the auditor, § 1773.5 references the specific requirements for an auditor to be considered satisfactory to RUS.

Comment (6): Amendment to Part 1770.13(a) does not agree with changes made to 1773.3.

Agency response (6): The only change made to § 1770.13(a) was to remove the title of 7 CFR part 1773 in the last sentence. Your comments will be considered in future revisions to these parts.

Comment (7): RUS uses the terms must, shall and should in the various parts impacted by the FR notice. We recommend RUS eliminate “shall” throughout the various Parts, define what is meant by “must” and “should” and then ensure the appropriate term is used throughout the Parts.

Agency response (7): We understand your concern. We are leaving the final rule as is, but will look at the use of must, should, and shall for when future updates are made.

Comment (8): We believe the RUS intent is to not include any appendices or exhibits to Part 1773. However, we noted the following document on the USDA website at: https://www.rd.usda.gov/files/UET_Bulletin_1773-1.pdf. This document appears to include several exhibits including illustrative auditor reports. If RUS plans to include any type of exhibit including information that would be issued by the auditor, we ask that the AICPA be provided an opportunity before it is issued.

Agency response (8): The RUS Bulletin 1773–1 will be officially rescinded when this final rule becomes effective. The Agency will ensure the bulletin is removed from the website.

The Agency appreciates the time that AICPA took to review, comment and question each section and will use that when the Agency next looks to update these sections.

No change to the rulemaking is necessary at this time. The RUS appreciates the comments received. The Agency confirms the final rule without change.

Andrew Berke,

Administrator, Rural Utilities Service.

[FR Doc. 2023–10413 Filed 5–17–23; 8:45 am]

BILLING CODE 3410–15–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2023–0160; Project Identifier MCAI–2022–01047–R; Amendment 39–22421; AD 2023–08–06]

RIN 2120–AA64

Airworthiness Directives; Airbus Helicopters

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is adopting a new airworthiness directive (AD) for certain Airbus Helicopters (Airbus) Model AS332C, AS332C1, AS332L, AS332L1, AS332L2, and EC225LP helicopters. This AD is prompted by modifications developed by Airbus to address a report of an emergency exit window that required excessive pushing force to jettison. This AD requires removing skived polytetrafluoroethylene tape (PTFE tape) (if installed) and replacing certain polychloroprene seals with silicone seals, as specified in a European Union Aviation Safety Agency (EASA) AD, which is incorporated by reference. This AD also prohibits installing a jettisonable window unless the actions required by this AD have been accomplished. The FAA is issuing this AD to address the unsafe condition on these products.

DATES: This AD is effective June 22, 2023.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of June 22, 2023.

ADDRESSES:

AD Docket: You may examine the AD docket at [regulations.gov](https://www.regulations.gov) under Docket No. FAA–2023–0160; 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 that is incorporated by reference in this final rule, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email ADs@easa.europa.eu; internet

easa.europa.eu. You may find the EASA material on the EASA website at ad.easa.europa.eu.

- You may view this service information at the FAA, Office of the Regional Counsel, Southwest Region, 10101 Hillwood Pkwy., Room 6N-321, Fort Worth, TX 76177. For information on the availability of this material at the FAA, call (817) 222-5110. It is also available at regulations.gov under Docket No. FAA-2023-0160.

FOR FURTHER INFORMATION CONTACT: Matthew Fuller, AD Program Manager, General Aviation & Rotorcraft Unit, Airworthiness Products Section, Operational Safety Branch, FAA, 10101 Hillwood Pkwy., Fort Worth, TX 76177; telephone (817) 222-5110; email matthew.fuller@faa.gov.

SUPPLEMENTARY INFORMATION:

Background

EASA, which is the Technical Agent for the Member States of the European Union, has issued a series of ADs, the most recent previously being EASA AD 2021-0012, dated January 11, 2021 (EASA AD 2021-0012), to correct an unsafe condition for certain Airbus Model AS332C, AS332C1, AS332L, AS332L1, AS332L2, and EC225LP helicopters.

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 by adding an AD that would apply to Airbus Model AS332C, AS332C1, AS332L, AS332L1, AS332L2, and EC225LP helicopters. The NPRM published in the **Federal Register** on February 8, 2023 (88 FR 8238). The NPRM was prompted by modifications developed by Airbus to address a report of an emergency exit window that required excessive pushing force to jettison. The NPRM proposed to require accomplishing the actions specified in EASA AD 2021-0012, described previously, as incorporated by reference, except for any differences identified as exceptions in the regulatory text of this AD and except as discussed under “Differences Between this AD and EASA AD 2021-0012.” The FAA is issuing this AD to address the unsafe condition on these products.

After the NPRM was issued, EASA AD 2021-0012 was revised with EASA AD 2021-0012R1, dated February 25, 2023 (EASA AD 2021-0012R1) to include an alternate method to modify the window jettisoning system. Because operators may request an alternate method of compliance for accomplishing the requirements of this AD, the FAA is not incorporating by reference EASA AD 2021-0012R1 but is incorporating by reference EASA AD 2021-0012 as proposed in the NPRM.

You may examine the MCAI in the AD docket at regulations.gov under Docket No. FAA-2023-0160.

Discussion of Final Airworthiness Directive

Comments

The FAA received no comments on the NPRM or on the determination of the costs.

Conclusion

These products have been approved by the aviation authority of another country and are 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 these products.

Related Service Information Under 1 CFR Part 51

EASA AD 2021-0012 requires modifying the windows jettisoning system.

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**.

Other Related Service Information

The FAA reviewed Airbus Alert Service Bulletin (ASB) No. AS332-56.00.16, Revision 0, dated February 10, 2020, Airbus ASB No. AS332-56.00.18, Revision 0, dated September 23, 2020, Airbus ASB No. AS332-56.00.20, Revision 0, dated September 23, 2020, Airbus ASB No. AS332-56.00.21, Revision 0, dated September 23, 2020, Airbus ASB No. AS332-56.90.14, Revision 0, dated April 10, 2019, Airbus ASB No. EC225-56A013, Revision 1, dated February 10, 2020, Airbus ASB No. EC225-56A015, Revision 0, dated February 10, 2020, Airbus ASB No. EC225-56A016, Revision 0, dated February 10, 2020, and Airbus ASB No. EC225-56A017, Revision 0, dated February 10, 2020. This service information specifies procedures for modifying the windows jettisoning system. Depending on your helicopter configuration, the service information specifies procedures for removing PTFE tape (if installed), discarding certain internal seal keys and external extraction tapes, installing plugs on certain snap fasteners, removing certain emergency exit installation indications, measuring the thickness of certain

windows, replacing certain windows, measuring the clearance between certain windows and the airframe, modifying certain assemblies of the external extraction tape with its associated marking (if necessary), and replacing certain polychloroprene seals with silicone seals.

The FAA also reviewed EASA AD 2021-0012R1, which requires modifying the windows jettisoning system and provides an alternate method for modifying the window jettisoning system than that required in EASA AD 2021-0012.

Differences Between This AD and EASA AD 2021-0012

EASA AD 2021-0012 requires compliance within 250 flight hours or 6 months for certain helicopters not operated over water and within 110 flight hours or 6 months for certain other helicopters operated over water. EASA AD 2021-0012 also requires compliance within 25 months for all other affected helicopters. However, this AD requires compliance within 110 hours time-in-service for all helicopters.

Where the service information referenced in EASA AD 2021-0012 specifies discarding parts, this AD requires removing those parts from service. The service information referenced in EASA AD 2021-0012 specifies contacting Airbus Helicopter to obtain a technical solution, whereas this AD requires repair done in accordance with a method approved by the FAA, EASA, or Airbus Helicopters’ EASA Design Organization Approval. The service information referenced in EASA AD 2021-0012 specifies using a video, whereas this AD does not.

This AD also prohibits installing a jettisonable window unless the actions required by this AD have been accomplished, whereas EASA AD 2021-0012 does not require any installation limitations.

Costs of Compliance

The FAA estimates that this AD affects 39 helicopters of U.S. Registry. Labor costs are estimated at \$85 per work-hour. Based on these numbers, the FAA estimates the following costs to comply with this AD.

Modifying a window takes about 2 work-hours and parts cost about \$220 for an estimated cost of \$390 per window. There may be up to twelve affected windows on a helicopter for an estimated cost of up to \$4,680 per helicopter and up to \$182,520 for the U.S. fleet.

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

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 adding the following new airworthiness directive:

2023–08–06 Airbus Helicopters:

Amendment 39–22421; Docket No. FAA–2023–0160; Project Identifier MCAI–2022–01047–R.

(a) Effective Date

This airworthiness directive (AD) is effective June 22, 2023.

(b) Affected ADs

Accomplishing the actions required by this AD terminates all requirements of AD 2020–20–08, Amendment 39–21264 (85 FR 70955, November 6, 2020).

(c) Applicability

This AD applies to Airbus Helicopters Model AS332C, AS332C1, AS332L, AS332L1, AS332L2, and EC225LP helicopters, certificated in any category, as identified in European Union Aviation Safety Agency (EASA) AD 2021–0012, dated January 11, 2021 (EASA AD 2021–0012).

(d) Subject

Joint Aircraft System Component (JASC) Code: 5220, Emergency Exits.

(e) Unsafe Condition

This AD was prompted by a report of an emergency exit window that required excessive pushing force to jettison caused by friction between the jettisonable window and the airframe. The FAA is issuing this AD to prevent excessive friction between the jettisonable cabin window and the airframe. The unsafe condition, if not addressed, could prevent the window from jettisoning, subsequently affecting the evacuation of passengers during an emergency situation.

(f) Compliance

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

(g) Requirements

(1) 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, EASA AD 2021–0012.

(2) As of the effective date of this AD, do not install a jettisonable window on any helicopter unless the actions required by this AD have been accomplished.

(h) Exceptions to EASA AD 2021–0012

(1) Where EASA AD 2021–0012 requires compliance in terms of flight hours, this AD requires using hours time-in-service.

(2) Where EASA AD 2021–0012 refers to its effective date, the effective date of EASA AD 2019–0107, dated May 16, 2019, and the effective date of EASA AD 2020–0061, dated March 17, 2020, this AD requires using the effective date of this AD.

(3) Where paragraph (1) of EASA AD 2021–0012 specifies compliance within 250 flight hours or 6 months for helicopters not operated over water and within 110 flight hours or 6 months for helicopters operated over water, this AD requires compliance within 110 hours time-in-service (TIS) for Group 1 and Group 2 helicopters, as defined in EASA AD 2021–0012.

(4) Where paragraph (2) of EASA AD 2021–0012 specifies compliance within 25 months,

this AD requires compliance within 110 hours TIS.

(5) Where the service information referenced in EASA AD 2021–0012 specifies discarding parts, this AD requires removing those parts from service.

(6) Where the service information referenced in EASA AD 2021–0012 specifies contacting Airbus Helicopters to obtain a technical solution, this AD requires repair done in accordance with a method approved by the Manager, General Aviation & Rotorcraft Section, International Validation Branch, FAA; or EASA; or Airbus Helicopters' EASA Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(7) Where the service information referenced in EASA AD 2021–0012 specifies to use tooling, this AD allows the use of equivalent tooling.

(8) Where the service information referenced in EASA AD 2021–0012 specifies using a video, this AD does not require using the video.

(9) Paragraph (3) of EASA AD 2021–0012 does not apply to this AD. Refer to paragraph (b) of this AD for affected FAA AD information.

(10) This AD does not adopt the Remarks paragraph of EASA AD 2021–0012.

(i) No Reporting Requirement

Although the service information referenced in EASA AD 2021–0012 specifies to submit certain information to the manufacturer, this AD does not include that requirement.

(j) Special Flight Permit

Special flight permits are prohibited for flights over water with passengers on board.

(k) Alternative Methods of Compliance (AMOCs)

(1) 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 local Flight Standards District Office, as appropriate. If sending information directly to the manager of the International Validation Branch, send it to the attention of the person identified in paragraph (l)(2) of this AD. Information may be emailed to: 9-AVS-AIR-730-AMOC@faa.gov.

(2) Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the local flight standards district office/certificate holding district office.

(l) Additional Information

(1) For Airbus Helicopters service information identified in this AD, contact Airbus Helicopters, Ala Ramaden, 2701 N Forum Drive, Grand Prairie, TX 75052, United States; phone: (972) 641–0000; website: airbus.com/helicopters/services/technical-support.html.

(2) For more information about this AD, contact Matthew Fuller, AD Program Manager, General Aviation & Rotorcraft Unit, Airworthiness Products Section, Operational

Safety Branch, FAA, 10101 Hillwood Pkwy., Fort Worth, TX 76177; telephone (817) 222-5110; email matthew.fuller@faa.gov.

(m) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference 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.

(i) European Union Aviation Safety Agency (EASA) AD 2021-0012, dated January 11, 2021.

(ii) [Reserved]

(3) For EASA AD 2021-0012, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; phone: +49 221 8999 000; email: ADs@easa.europa.eu. You may find this material on the EASA website at ad.easa.europa.eu.

(4) You may view this service information at FAA, Office of the Regional Counsel, Southwest Region, 10101 Hillwood Pkwy., Room 6N-321, Fort Worth, TX 76177. For information on the availability of this material at the FAA, call (817) 222-5110.

(5) You may view this service information 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 April 19, 2023.

Christina Underwood,

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

[FR Doc. 2023-10620 Filed 5-17-23; 8:45 am]

BILLING CODE 4910-13-P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA-2022-1586; Airspace
Docket No. 22-AGL-19]

RIN 2120-AA66

Amendment of V-171 in the Vicinity of Roseau, MN

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends Very High Frequency (VHF) Omnidirectional Range (VOR) Federal airway V-171 in the vicinity of Roseau, MN. The amendment is due to the planned decommissioning of the VOR portion of the Roseau, MN (ROX), VOR/Distance Measuring Equipment (VOR/DME) navigational aid (NAVAID). The Roseau VOR is being decommissioned as part of

the FAA's VOR Minimum Operational Network (MON) program.

DATES: Effective date 0901 UTC, August 10, 2023. The Director of the Federal Register approves this incorporation by reference action under 1 CFR part 51, subject to the annual revision of FAA Order JO 7400.11 and publication of conforming amendments.

ADDRESSES: A copy of the NPRM, all comments received, this final rule, and all background material may be viewed online at www.regulations.gov using the FAA Docket number. Electronic retrieval help and guidelines are available on the website. It is available 24 hours each day, 365 days each year. An electronic copy of this document may also be downloaded from the Office of the Federal Register's website at www.federalregister.gov.

FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at www.faa.gov/air_traffic/publications/. You may also contact the Rules and Regulations Group, Office of Policy, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267-8783.

FOR FURTHER INFORMATION CONTACT: Colby Abbott, Rules and Regulations Group, Office of Policy, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267-8783.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. 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. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of the airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would modify the Air Traffic Service (ATS) route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System.

History

The FAA published a notice of proposed rulemaking for Docket No. FAA-2022-1586 in the **Federal Register** (87 FR 75974; December 12, 2022), amending VOR Federal airway V-171

due to the planned decommissioning of the VOR portion of the Roseau, MN, VOR/DME NAVAID. Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal. No comments were received.

Incorporation by Reference

VOR Federal airways are published in paragraph 6010(a) of FAA Order JO 7400.11, Airspace Designations and Reporting Points, which is incorporated by reference in 14 CFR 71.1 on an annual basis. This document amends the current version of that order, FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022. FAA Order JO 7400.11G is publicly available as listed in the **ADDRESSES** section of this document. This amendment action will be published in the next update to FAA Order JO 7400.11.

FAA Order JO 7400.11G lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

The Rule

This action amends 14 CFR part 71 by amending VOR Federal airway V-171 due to the planned decommissioning of the VOR portion of Roseau, MN, VOR/DME NAVAID. The airway action is described below.

V-171: V-171 extends between the Lexington, KY, VOR/DME and the Joliet, IL, VOR/DME; and between the Nodine, MN, VOR/Tactical Air Navigation (VORTAC) and the Roseau, MN, VOR/DME. The airway segment between the Grand Forks, ND, VOR/DME and the Roseau, MN, VOR/DME is removed. As amended, the airway extends between the Lexington VOR/DME and the Joliet VOR/DME; and between the Nodine VORTAC and the Grand Forks VOR/DME.

The NAVAID radials contained in the V-171 airway description below are unchanged and stated in degrees True north.

Regulatory Notices and Analyses

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore: (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that only affects air traffic

procedures and air navigation, it is certified that this rule, when promulgated, does not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

The FAA has determined that this action of amending VOR Federal airway V-171, due to the planned decommissioning of the VOR portion of the Roseau, MN, VOR/DME NAVAID, qualifies for categorical exclusion under the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*) and its implementing regulations at 40 CFR part 1500, and in accordance with FAA Order 1050.1F, Environmental Impacts: Policies and Procedures, paragraph 5-6.5a, which categorically excludes from further environmental impact review rulemaking actions that designate or modify classes of airspace areas, airways, routes, and reporting points (see 14 CFR part 71, Designation of Class A, B, C, D, and E Airspace Areas; Air Traffic Service Routes; and Reporting Points); paragraph 5-6.5b, which categorically excludes from further environmental impact review actions regarding establishment of jet routes and Federal airways (see 14 CFR 71.15, Designation of jet routes and VOR Federal airways); and paragraph 5-6.5i, which categorically excludes from further environment impact review the establishment of new or revised air traffic control procedures conducted at 3,000 feet or more above ground level (AGL); procedures conducted below 3,000 feet AGL that do not cause traffic to be routinely routed over noise sensitive areas; modifications to currently approved procedures conducted below 3,000 feet AGL that do not significantly increase noise over noise sensitive areas; and increases in minimum altitudes and landing minima. As such, this action is not expected to result in any potentially significant environmental impacts. In accordance with FAA Order 1050.1F, paragraph 5-2 regarding Extraordinary Circumstances, the FAA has reviewed this action for factors and circumstances in which a normally categorically excluded action may have a significant environmental impact requiring further analysis. The FAA has determined that no extraordinary circumstances exist that warrant preparation of an environmental assessment or environmental impact study.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Amendment

In consideration of the foregoing, the Federal Aviation Administration amends 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

■ 1. The authority citation for 14 CFR part 71 continues to read as follows:

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order JO 7400.11G, Airspace Designations and Reporting Points, dated August 19, 2022, and effective September 15, 2022, is amended as follows:

Paragraph 6010(a) Domestic VOR Federal Airways.

* * * * *

V-171 [Amended]

From Lexington, KY; INT Lexington 251° and Louisville, KY, 114° radials; Louisville; Terre Haute, IN; Danville, IL; Peotone, IL; INT Peotone 281° and Joliet, IL, 173° radials; to Joliet. From Nodine, MN; INT Nodine 298° and Farmington, MN, 124° radials; Farmington; Darwin, MN; Alexandria, MN; INT Alexandria 321° and Grand Forks, ND, 152° radials; to Grand Forks.

* * * * *

Issued in Washington, DC, on May 11, 2023.

Brian Konie,

Acting Manager, Airspace Rules and Regulations.

[FR Doc. 2023–10501 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 131

[Docket No. FDA–2000–P–0126 (formerly Docket No. 2000P–0658)]

International Dairy Foods Association: Response to the Objections and Requests for a Public Hearing on the Final Rule To Revoke the Standards for Lowfat Yogurt and Nonfat Yogurt and Amend the Standard for Yogurt; Correction

AGENCY: Food and Drug Administration, HHS.

ACTION: Final order; response to objections and denial of public hearing

requests; removal of administrative stay; final amendment; correction.

SUMMARY: The Food and Drug Administration (FDA or we) is correcting a final order that appeared in the **Federal Register** on April 14, 2023. The document responded to objections and requests for a public hearing on the final rule to revoke the standards for lowfat yogurt and nonfat yogurt and amend the standard for yogurt. The final order published with an inadvertent error. This document corrects that error. **DATES:** Effective May 18, 2023.

FOR FURTHER INFORMATION CONTACT:

Andrea Krause, Center for Food Safety and Applied Nutrition (HFS–820), Food and Drug Administration, 5001 Campus Dr., College Park, MD 20740, 240–402–2371, or Holli Kubicki, Center for Food Safety and Applied Nutrition, Office of Regulations and Policy (HFS–024), Food and Drug Administration, 5001 Campus Dr., College Park, MD 20740, 240–402–2378.

SUPPLEMENTARY INFORMATION:

Correction

In the **Federal Register** of April 14, 2023 (88 FR 22907), in FR Doc. 2023–07723, the following correction is made:

On page 22908, in the first column, under **DATES**, the compliance date is corrected to read: “January 1, 2024”.

Dated: May 15, 2023.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2023–10606 Filed 5–17–23; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF LABOR

Employee Benefits Security Administration

29 CFR Part 2520

RIN 1210–AB97

Annual Reporting and Disclosure

AGENCY: Employee Benefits Security Administration, Labor.

ACTION: Final rule; technical correction; change to operational date.

SUMMARY: On February 24, 2023, the Employee Benefits Security Administration for the U.S. Department of Labor (the Department or DOL) published a final rule on annual reporting requirements under Title I of the Employee Retirement Income Security Act of 1974, as amended (ERISA). This document contains two technical changes to the regulations: it changes the operational date of the final

rule amendments to the regulations to address the Congressional Review Act (CRA) requirement under which a major rule cannot be effective until 60 days after publication in the **Federal Register** or receipt by Congress, whichever is later. The other corrects a typographical error in the lettering of a paragraph in the regulations.

DATES: This final rule is effective May 31, 2023. The operational date of the amendments published at 88 FR 11793 is changed from April 25, 2023, to May 31, 2023.

FOR FURTHER INFORMATION CONTACT: Janet Song, Florence Novellino or Colleen Brisport Sequeda, Office of Regulations and Interpretations, Employee Benefits Security Administration, U.S. Department of Labor, (202) 693–8500 (this is not a toll-free number).

SUPPLEMENTARY INFORMATION:

A. Background

On February 24, 2023, the Department of Labor (DOL or Department), the Internal Revenue Service (IRS) and the Pension Benefit Guaranty Corporation (PBGC) published **Federal Register** notices that announced changes to the Form 5500 Annual Return/Report of Employee Benefit Plan and Form 5500–SF Short Form Annual Return/Report of Small Employee Benefit Plan. For DOL, the final rule included a Notice of Final Forms Revisions (Final Forms Revisions) jointly issued by the DOL, IRS and PBGC, and a DOL-only Final Rule (Final Rule) that made corresponding changes to the DOL annual reporting regulations under Title I of ERISA.¹

¹ See Notice of Final Forms Revisions at 88 FR 11984 and Final Rule at 88 FR 11793. The DOL, IRS, PBGC treat the Form 5500 annual return/report as an “information collection” subject to the Paperwork Reduction Act (PRA), but, due to the statutory and regulatory provisions in Title I of ERISA governing annual reporting by employee benefit plans, DOL changes to the forms and instructions generally are rules under the Administrative Procedure Act (APA). Sometimes changes in the forms and instructions do not require changes to the DOL’s underlying reporting regulations. In those cases, one **Federal Register** notice is used as both the PRA notice and the APA rulemaking document. See, e.g., www.federalregister.gov/documents/2022/05/23/2022-10658/annual-information-return-reports. When changes to the forms and schedules require amendments to DOL’s annual reporting regulations (as they did here with the addition of new schedules and a new reporting option), there is a tri-agency notice with IRS and PBGC that includes the PRA sections and DOL publishes a separate notice with the regulatory amendments and the APA rulemaking components (e.g., regulatory impact analysis and CRA classification). The Final Forms Revisions and Final Rule include cross-references that are intended to communicate the connectedness of the notices as a final rule.

Pursuant to the Congressional Review Act (CRA), OMB designated the final rule as a “major rule,” as defined by 5 U.S.C. 804(2).² The changes to the annual return/report forms, instructions, and regulations are applicable to annual return/reports for plan years beginning on or after January 1, 2023, (see 88 FR 11984). Annual return/reports generally are due to be filed beginning seven months after the end of the applicable plan year (e.g., July 31, 2024, for 2023 annual return/reports for calendar year plans). The Final Rule had a stated effective date of April 25, 2023, (see 88 FR 11793).

The Final Rule included additions to the ERISA annual reporting regulations to implement the directive to the Secretary of Labor in section 202 of the Setting Every Community Up for Retirement Enhancement Act of 2019, commonly known as the SECURE Act, to jointly with the Secretary of the Treasury provide for a single, consolidated Form 5500 filing option that would satisfy the annual reporting obligations for the defined contribution pension plans participating in a Defined Contribution Group (DCG) reporting arrangement. The Final Rule included newly added regulations at 29 CFR 2520.103–14 and 2520.104–51 setting forth requirements applicable to the DCG reporting arrangement, the participating plans, and the content of the consolidated Form 5500 filing.

B. CRA Date

The CRA requires that before a final rule can take effect it must be submitted to the Senate and the House of Representatives and to the Government Accountability Office (GAO), along with a concise general statement of the rule and its effective date.³ Under the CRA, as pertinent here, the effective date of a major rule (which corresponds to an operational date in a **Federal Register** rule document) must be no earlier than “the later of the date occurring 60 days after the date on which . . . the Congress received the [required] report . . . or . . . the rule is published in the **Federal Register**” As noted above, the Final Rule and Final Forms

² See 88 FR at 11797.

³ See 5 U.S.C. 801–808. Under the Congressional Review Act (CRA) two types of rules, major and nonmajor, must be submitted to both Houses of Congress and GAO before either can take effect. CRA defines a “major” rule as one which has resulted in or is likely to result in (1) an annual effect on the economy of \$100 million or more; (2) a major increase in costs or prices for consumers, individual industries, government agencies, or geographic regions; or (3) significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of U.S.-based enterprises to compete with foreign-based enterprises in domestic and export markets.

Revisions were designated as a major rule for DOL and were published in the **Federal Register** on February 24, 2023. Although the report to GAO was delivered via the GAO electronic process for CRA submissions⁴ on February 24, 2023, the Congressional Record reflects that the House received the final rule on February 28, 2023, 169 Cong. Rec. H1111 (daily ed. Mar. 3, 2023), and the Senate on March 6, 2023, 169 Cong. Rec. S858 (daily ed. March 21, 2023). As noted above, the Final Rule’s notice at 88 FR 11793 published on February 24, 2023, in the **Federal Register**, has a stated effective date of April 25, 2023 (which means that the **Federal Register** rule’s operational date was also April 25, 2023). Therefore, based on the dates of House and Senate receipt, that stated CRA effective date is earlier than 60 days after the receipt by Congress of the published final rule. In light of the fact that the April 25 effective date has passed, this final rule changes the operational date of April 25, 2023 to May 31, 2023, a date that is later than 60 days after receipt of the published rule by Congress.

C. 29 CFR 2520.103–14 Paragraph Lettering

The Final Rule added 29 CFR 2520.103–14 as a new annual reporting regulation that sets forth requirements for the consolidated annual report for a DCG reporting arrangement. The preamble of the Final Rule stated that paragraph (c) of § 2520.103–14 provides that DCG reporting arrangements must comply with the electronic filing requirements that apply to all plan filers and direct filing entities, including the requirement that the common plan administrator of all the participating plans that is filing the consolidated Form 5500 must maintain an original copy, with all required signatures, as part of its records (which also would be treated as records of each of the participating plans). The published regulatory text, however, omitted paragraph (c) and designated the paragraph as paragraph (d). The Department is correcting the paragraph lettering to designate the paragraph as paragraph (c).

D. Good Cause Findings Under 5 U.S.C. 553(b)(3)(B) and 553(d)(3)

Under 5 U.S.C. 553(b) of the Administrative Procedure Act (APA), an agency is required to publish a notice of the proposed rule in the **Federal Register** before the provisions of a rule take effect. In addition, section 553(d) of

⁴ See GAO’s CRA FAQ at www.gao.gov/legal/other-legal-work/congressional-review-act.

the APA mandates a 30-day delay in effective date after issuance or publication of a substantive rule. Sections 553(b)(3)(B) and 553(d)(3) of the APA provide for exceptions from the APA notice and comment, and delay in effective date requirements. Section 553(b)(3)(B) of the APA authorizes an agency to dispense with normal notice and comment rulemaking procedures for good cause if the agency makes a finding that the notice and comment process is impracticable, unnecessary, or contrary to the public interest, and includes a statement of the finding and the reasons for it in the rule. Similarly, section 553(d)(3) of the APA allows the agency to avoid the 30-day delay in effective date where good cause is found and the agency includes in the rule a statement of the finding and the reasons for it.

The Department is publishing the change of the operational date without advance notice or an opportunity for comment because it falls under the “good cause” exemption of the Administrative Procedure Act, 5 U.S.C. 553(b)(3)(B). Undertaking notice and comment procedures to incorporate the corrections in this document would be contrary to the public interest because it is in the public interest to timely provide a final rule that accurately reflects changes to the annual return/report forms, instructions, and regulations that are applicable to annual return/reports for plan years beginning on or after January 1, 2023. Further, such procedures would be unnecessary because the Department is not making substantive revisions to the Final Rule, but rather, it is changing the operational date by 36 days from April 25, 2023, to May 31, 2023, to reflect the CRA requirement that the effective date be no earlier than 60 days from receipt of the rule by the Congress. The Department, accordingly, finds good cause under 5 U.S.C. 553(b)(3)(B) to waive public comment. For the same reasons, the Department similarly finds good cause under 5 U.S.C. 555(d)(3) to avoid the 30-day delay in effective date after issuance of a substantive rule.⁵

List of Subjects in 29 CFR Part 2520

Accounting, Employee benefit plans, Freedom of information, Pensions, Public assistance programs, Reporting and recordkeeping requirements.

⁵ The Department is not making a “good cause” finding for fixing the typographical error in the paragraph lettering in 29 CFR 2520.103–14 because it does not impose any new or substantive requirement subject to the APA notice and comment or effective date provisions.

For the reasons discussed in the preamble, 29 CFR part 2520 is amended as follows:

PART 2520—RULES AND REGULATIONS FOR REPORTING AND DISCLOSURE

■ 1. The authority citation for part 2520 continues to read as follows:

Authority: 29 U.S.C. 1002(44), 1021–1025, 1027, 1029–31, 1059, 1134, and 1135; and Secretary of Labor’s Order 1–2011, 77 FR 1088. Sec. 2520.101–2 also issued under 29 U.S.C. 1132, 1181–1183, 1181 note, 1185, 1185a–b, 1191, and 1191a–c. Sec. 2520.101–5 also issued under 29 U.S.C. 1021 note; sec. 501, Pub. L. 109–280, 120 Stat. 780; sec. 105(a), Pub. L. 110–458, 122 Stat. 5092. Secs. 2520.102–3, 2520.104b–1, and 2520.104b–3 also issued under 29 U.S.C. 1003, 1181–1183, 1181 note, 1185, 1185a–b, 1191, and 1191a–c. Secs. 2520.104b–1 and 2520.107 also issued under 26 U.S.C. 401 note; sec. 1510, Pub. L. 105–34, 111 Stat. 1068.

§ 2520.103–14 [Amended]

■ 2. In § 2520.103–14, redesignate paragraph (d) as paragraph (c).

Signed at Washington, DC, this 26th day of April, 2023.

Lisa M. Gomez,

Assistant Secretary, Employee Benefits Security Administration, U.S. Department of Labor.

[FR Doc. 2023–09227 Filed 5–17–23; 8:45 am]

BILLING CODE 4510–29–P

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

31 CFR Part 558

South Sudan Sanctions Regulations

AGENCY: Office of Foreign Assets Control, Treasury.

ACTION: Final rule.

SUMMARY: The Department of the Treasury’s Office of Foreign Assets Control (OFAC) is adopting a final rule amending the South Sudan Sanctions Regulations to further implement an April 3, 2014 South Sudan-related Executive order and replacing the South Sudan Regulations that were published in abbreviated form on July 1, 2014 with a more comprehensive set of regulations that includes additional interpretive and definitional guidance, general licenses, and other regulatory provisions that will provide further guidance to the public.

DATES: This rule is effective May 18, 2023.

FOR FURTHER INFORMATION CONTACT:

OFAC: Assistant Director for Licensing, 202–622–2480; Assistant Director for

Regulatory Affairs, 202–622–4855; or Assistant Director for Sanctions Compliance & Evaluation, 202–622–2490.

SUPPLEMENTARY INFORMATION:

Electronic Availability

This document and additional information concerning OFAC are available on OFAC’s website: www.treas.gov/ofac.

Background

On July 1, 2014, OFAC issued the South Sudan Sanctions Regulations, 31 CFR part 558 (79 FR 37190, July 1, 2014) (the “Regulations”), to implement Executive Order (E.O.) 13664 of April 3, 2014, “Blocking Property of Certain Persons With Respect to South Sudan” (79 FR 19283, April 7, 2014), pursuant to authorities delegated to the Secretary of the Treasury in E.O. 13664. The Regulations were initially issued in abbreviated form for the purpose of providing immediate guidance to the public. OFAC is revising the Regulations to further implement E.O. 13664. OFAC is amending and reissuing the Regulations as a more comprehensive set of regulations that includes additional interpretive guidance and definitions, general licenses, and other regulatory provisions that will provide further guidance to the public. Due to the number of regulatory sections being updated or added, OFAC is reissuing the Regulations in their entirety.

On April 3, 2014, the President, invoking the authority of, *inter alia*, the International Emergency Economic Powers Act (50 U.S.C. 1701 *et seq.*) (IEEPA), issued E.O. 13664. In E.O. 13664, the President found that the situation in and in relation to South Sudan, which has been marked by activities that threaten the peace, security, or stability of South Sudan and the surrounding region, including widespread violence and atrocities, human rights abuses, recruitment and use of child soldiers, attacks on peacekeepers, and obstruction of humanitarian operations, poses an unusual and extraordinary threat to the national security and foreign policy of the United States and declared a national emergency to deal with that threat.

Section 1(a) of E.O. 13664 blocks, with certain exceptions, all property and interests in property that are in the United States, that come within the United States, or that are or come within the possession or control of any U.S. person of: any person determined by the Secretary of the Treasury, in

consultation with the Secretary of State: (i) to be responsible for or complicit in, or to have engaged in, directly or indirectly, any of the following in or in relation to South Sudan: (A) actions or policies that threaten the peace, security, or stability of South Sudan; (B) actions or policies that threaten transitional agreements or undermine democratic processes or institutions in South Sudan; (C) actions or policies that have the purpose or effect of expanding or extending the conflict in South Sudan or obstructing reconciliation or peace talks or processes; (D) the commission of human rights abuses against persons in South Sudan; (E) the targeting of women, children, or any civilians through the commission of acts of violence (including killing, maiming, torture, or rape or other sexual violence), abduction, forced displacement, or attacks on schools, hospitals, religious sites, or locations where civilians are seeking refuge, or through conduct that would constitute a serious abuse or violation of human rights or a violation of international humanitarian law; (F) the use or recruitment of children by armed groups or armed forces in the context of the conflict in South Sudan; (G) the obstruction of the activities of international peacekeeping, diplomatic, or humanitarian missions in South Sudan, or of the delivery or distribution of, or access to, humanitarian assistance; or (H) attacks against United Nations missions, international security presences, or other peacekeeping operations; (ii) to be a leader of (A) an entity, including any government, rebel militia, or other group, that has, or whose members have, engaged in any of the activities described in subsection 1(a)(i) of E.O. 13664 or (B) an entity whose property and interests in property are blocked pursuant to E.O. 13664; (iii) to have materially assisted, sponsored, or provided financial, material, logistical, or technological support for, or goods or services in support of (A) any of the activities described in subsection 1(a)(i) of E.O. 13664 or (B) any person whose property and interests in property are blocked pursuant to E.O. 13664; or (iv) to be owned or controlled by, or to have acted or purported to act for or on behalf of, directly or indirectly, any person whose property and interests in property are blocked pursuant to E.O. 13664. The property and interests in property of the persons described above may not be transferred, paid, exported, withdrawn, or otherwise dealt in.

In Section 2 of E.O. 13664, the President determined that the making of

donations of the type of articles specified in section 203(b)(2) of IEEPA (50 U.S.C. 1702(b)(2)), by, to, or for the benefit of any person whose property and interests in property are blocked pursuant to E.O. 13664 would seriously impair the President's ability to deal with the national emergency declared in E.O. 13664. The President therefore prohibited the donation of such items.

Section 3 of E.O. 13664 provides that the prohibition on any transaction or dealing in blocked property or interests in property includes the making of any contribution or provision of funds, goods, or services by, to, or for the benefit of any person whose property and interests in property are blocked pursuant to E.O. 13664, and the receipt of any contribution or provision of funds, goods, or services from any such person.

Section 5 of E.O. 13664 prohibits any transaction that evades or avoids, has the purpose of evading or avoiding, causes a violation of, or attempts to violate any of the prohibitions set forth in E.O. 13664, as well as any conspiracy formed to violate such prohibitions.

Section 8 of E.O. 13664 authorizes the Secretary of the Treasury, in consultation with the Secretary of State, to take such actions, including the promulgation of rules and regulations, and to employ all powers granted to the President by IEEPA as may be necessary to carry out the purposes of E.O. 13664. Section 8 of E.O. 13664 also provides that the Secretary of the Treasury may redelegate any of these functions to other officers and agencies of the U.S. government. In furtherance of the purposes of E.O. 13664, OFAC is revising 31 CFR part 558.

The Regulations implement targeted sanctions that are directed at persons determined to meet the criteria set forth in § 558.201 of the Regulations, as well as sanctions that may be set forth in any future Executive orders issued pursuant to the national emergency declared in E.O. 13664. The sanctions in E.O. 13664 do not generally prohibit trade or the provision of banking or other financial services to the country of South Sudan. Instead, the sanctions in E.O. 13664 apply where the transaction or service in question involves property or interests in property that are blocked pursuant to these sanctions.

Subpart A of the Regulations clarifies the relation of this part to other laws and regulations. Subpart B of the Regulations implements the prohibitions contained in sections 1, 2, 3, and 5 of E.O. 13664, as well as the prohibitions contained in any further Executive orders issued pursuant to the national emergency declared in E.O.

13664. *See, e.g.*, §§ 558.201 and 558.205. Persons designated by or under the authority of the Secretary of the Treasury pursuant to E.O. 13664, or otherwise blocked pursuant to E.O. 13664, as well as persons who are blocked pursuant to any further Executive orders issued pursuant to the national emergency declared in E.O. 13664, are referred to throughout the Regulations as “persons whose property and interests in property are blocked pursuant to § 558.201.” The names of persons designated or identified as blocked pursuant to E.O. 13664, or any further Executive orders issued pursuant to the national emergency declared therein, are published on OFAC's Specially Designated Nationals and Blocked Persons List (SDN List), which is accessible via OFAC's website. Those names also are published in the **Federal Register** as they are added to the SDN List.

Sections 558.202 and 558.203 of subpart B detail the effect of transfers of blocked property in violation of the Regulations and set forth the requirement to hold blocked funds, such as currency, bank deposits, or liquidated financial obligations, in interest-bearing blocked accounts. Section 558.204 of subpart B provides that all expenses incident to the maintenance of blocked tangible property shall be the responsibility of the owners and operators of such property, and that such expenses shall not be met from blocked funds, unless otherwise authorized. The section further provides that blocked property may, in OFAC's discretion, be sold or liquidated and the net proceeds placed in a blocked interest-bearing account in the name of the owner of the property.

Section 558.205 of subpart B prohibits any transaction that evades or avoids, has the purpose of evading or avoiding, causes a violation of, or attempts to violate any of the prohibitions set forth in § 558.201 of the Regulations, and any conspiracy formed to violate such prohibitions.

Section 558.206 of subpart B details transactions that are exempt from the prohibitions of the Regulations pursuant to section 203(b) of IEEPA (50 U.S.C. 1702(b)).

In subpart C of the Regulations, new definitions are being added to other key terms used throughout the Regulations. Because these new definitions were inserted in alphabetical order, the definitions that were in the prior abbreviated set of regulations have been renumbered. Similarly, in subpart D, which contains interpretive sections regarding the Regulations, certain provisions have been renumbered and

others added to those in the prior abbreviated set of regulations. Section 558.411 of subpart D explains that the property and interests in property of an entity are blocked if the entity is directly or indirectly owned, whether individually or in the aggregate, 50 percent or more by one or more persons whose property and interests in property are blocked, whether or not the entity itself is incorporated into OFAC's SDN List.

Transactions otherwise prohibited by the Regulations but found to be consistent with U.S. policy may be authorized by one of the general licenses contained in subpart E of the Regulations or by a specific license issued pursuant to the procedures described in subpart E of 31 CFR part 501. General licenses and statements of licensing policy relating to this part also may be available through the South Sudan-related sanctions page on OFAC's website: www.treas.gov/ofac.

OFAC is adding a new general license to the Regulations, renumbering existing general licenses, and making technical edits to certain existing general licenses. The new general license, which authorizes U.S. financial institutions to invest and reinvest certain blocked assets, is being added at § 558.506. Existing § 558.506, regarding the provision of legal services, is being renumbered as § 558.507, and existing § 558.507, regarding payments for legal services from funds originating outside the United States, is being renumbered as § 558.508. The authorization for emergency medical services is being renumbered from existing § 558.508 to § 558.509, and OFAC is removing the requirement that the receipt of payment for emergency medical services be specifically licensed. Sections 558.509, 558.510, 558.511, and 558.512, authorizing official business of the U.S. government; official business of certain international organizations and entities; transactions in support of nongovernmental organizations; and transactions related to the provision of agricultural commodities, medicine, medical devices, and other items, respectively, are being renumbered as §§ 558.510, 558.511, 558.512, and 558.513, respectively.

Subpart F of the Regulations refers to subpart C of part 501 for recordkeeping and reporting requirements. Subpart G of the Regulations describes the civil and criminal penalties applicable to violations of the Regulations, as well as the procedures governing the potential imposition of a civil monetary penalty or issuance of a Finding of Violation. Subpart G also refers to appendix A of

part 501 for a more complete description of these procedures.

Subpart H of the Regulations refers to subpart E of part 501 for applicable provisions relating to administrative procedures and contains a delegation of certain authorities of the Secretary of the Treasury. Subpart I of the Regulations sets forth a Paperwork Reduction Act notice.

Public Participation

Because the Regulations involve a foreign affairs function, the provisions of E.O. 12866 of September 30, 1993, "Regulatory Planning and Review" (58 FR 51735, October 4, 1993), and the Administrative Procedure Act (5 U.S.C. 553) requiring notice of proposed rulemaking, opportunity for public participation, and delay in effective date are inapplicable. Because no notice of proposed rulemaking is required for this rule, the Regulatory Flexibility Act (5 U.S.C. 601–612) does not apply.

Paperwork Reduction Act

The collections of information related to the Regulations are contained in 31 CFR part 501 (the "Reporting, Procedures and Penalties Regulations"). Pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), those collections of information have been approved by the Office of Management and Budget under control number 1505–0164. 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 control number.

List of Subjects in 31 CFR Part 558

Administrative practice and procedure, Banks, Banking, Blocking of assets, Credit, Foreign trade, Penalties, Reporting and recordkeeping requirements, Sanctions, Securities, Services, South Sudan.

For the reasons set forth in the preamble, OFAC revises 31 CFR part 558 to read as follows:

PART 558—SOUTH SUDAN SANCTIONS REGULATIONS

Subpart A—Relation of This Part to Other Laws and Regulations

Sec.

558.101 Relation of this part to other laws and regulations.

Subpart B—Prohibitions

558.201 Prohibited transactions.

558.202 Effect of transfers violating the provisions of this part.

558.203 Holding of funds in interest-bearing accounts; investment and reinvestment.

558.204 Expenses of maintaining blocked tangible property; liquidation of blocked property.

558.205 Evasions; attempts; causing violations; conspiracies.

558.206 Exempt transactions.

Subpart C—General Definitions

558.300 Applicability of definitions.

558.301 Blocked account; blocked property.

558.302 Effective date.

558.303 Entity.

558.304 Financial, material, logistical, or technological support.

558.305 [Reserved]

558.306 Interest.

558.307 Licenses; general and specific.

558.308 OFAC.

558.309 Person.

558.310 Property; property interest.

558.311 Transfer.

558.312 United States.

558.313 United States person; U.S. person.

558.314 U.S. financial institution.

Subpart D—Interpretations

558.401 Reference to amended sections.

558.402 Effect of amendment.

558.403 Termination and acquisition of an interest in blocked property.

558.404 Transactions ordinarily incident to a licensed transaction.

558.405 Provision and receipt of services.

558.406 Offshore transactions involving blocked property.

558.407 Payments from blocked accounts to satisfy obligations prohibited.

558.408 Charitable contributions.

558.409 Credit extended and cards issued by financial institutions to a person whose property and interests in property are blocked.

558.410 Setoffs prohibited.

558.411 Entities owned by one or more persons whose property and interests in property are blocked.

Subpart E—Licenses, Authorizations, and Statements of Licensing Policy

558.501 General and specific licensing procedures.

558.502 Effect of license or other authorization.

558.503 Exclusion from licenses.

558.504 Payments and transfers to blocked accounts in U.S. financial institutions.

558.505 Entries in certain accounts for normal service charges.

558.506 Investment and reinvestment of certain funds.

558.507 Provision of certain legal services.

558.508 Payments for legal services from funds originating outside the United States.

558.509 Emergency medical services.

558.510 Official business of the United States government.

558.511 Official business of certain international organizations and entities.

558.512 Certain transactions in support of nongovernmental organizations' activities.

558.513 Transactions related to the provision of agricultural commodities, medicine, medical devices, replacement parts and components, or software

updates for personal, non-commercial use.

Subpart F—Reports

558.601 Records and reports.

Subpart G—Penalties and Findings of Violation

558.701 Penalties.
558.702 Pre-Penalty Notice; settlement.
558.703 Penalty imposition.
558.704 Administrative collection; referral to United States Department of Justice.
558.705 Findings of Violation.

Subpart H—Procedures

558.801 Procedures.
558.802 Delegation of certain authorities of the Secretary of the Treasury.

Subpart I—Paperwork Reduction Act

558.901 Paperwork Reduction Act notice.

Authority: 3 U.S.C. 301; 31 U.S.C. 321(b); 50 U.S.C. 1601–1651, 1701–1706; Pub. L. 101–410, 104 Stat. 890, as amended (28 U.S.C. 2461 note); E.O. 13664, 79 FR 19283, 3 CFR, 2014 Comp., p. 238.

Subpart A—Relation of This Part to Other Laws and Regulations

§ 558.101 Relation of this part to other laws and regulations.

This part is separate from, and independent of, the other parts of this chapter, with the exception of part 501 of this chapter, the recordkeeping and reporting requirements and license application and other procedures of which apply to this part. Actions taken pursuant to part 501 of this chapter with respect to the prohibitions contained in this part are considered actions taken pursuant to this part. Differing foreign policy and national security circumstances may result in differing interpretations of similar language among the parts of this chapter. No license or authorization contained in or issued pursuant to those other parts authorizes any transaction prohibited by this part. No license or authorization contained in or issued pursuant to any other provision of law or regulation authorizes any transaction prohibited by this part. No license or authorization contained in or issued pursuant to this part relieves the involved parties from complying with any other applicable laws or regulations.

Subpart B—Prohibitions

§ 558.201 Prohibited transactions.

(a) All property and interests in property that are in the United States, that come within the United States, or that are or come within the possession or control of any U.S. person of the following persons are blocked and may not be transferred, paid, exported, withdrawn, or otherwise dealt in:

(1) Any person determined by the Secretary of the Treasury, in consultation with the Secretary of State:

(i) To be responsible for or complicit in, or to have engaged in, directly or indirectly, any of the following in or in relation to South Sudan:

(A) Actions or policies that threaten the peace, security, or stability of South Sudan;

(B) Actions or policies that threaten transitional agreements or undermine democratic processes or institutions in South Sudan;

(C) Actions or policies that have the purpose or effect of expanding or extending the conflict in South Sudan or obstructing reconciliation or peace talks or processes;

(D) The commission of human rights abuses against persons in South Sudan;

(E) The targeting of women, children, or any civilians through the commission of acts of violence (including killing, maiming, torture, or rape or other sexual violence), abduction, forced displacement, or attacks on schools, hospitals, religious sites, or locations where civilians are seeking refuge, or through conduct that would constitute a serious abuse or violation of human rights or a violation of international humanitarian law;

(F) The use or recruitment of children by armed groups or armed forces in the context of the conflict in South Sudan;

(G) The obstruction of the activities of international peacekeeping, diplomatic, or humanitarian missions in South Sudan, or of the delivery or distribution of, or access to, humanitarian assistance; or

(H) Attacks against United Nations missions, international security presences, or other peacekeeping operations;

(ii) To be a leader of:

(A) An entity, including any government, rebel militia, or other group, that has, or whose members have, engaged in any of the activities described in paragraph (a)(1)(i) of this section; or

(B) An entity whose property and interests in property are blocked pursuant to E.O. 13664;

(iii) To have materially assisted, sponsored, or provided financial, material, logistical, or technological support for, or goods or services in support of:

(A) Any of the activities described in paragraph (a)(1)(i) of this section; or

(B) Any person whose property and interests in property are blocked pursuant to E.O. 13664; or

(iv) To be owned or controlled by, or to have acted or purported to act for or on behalf of, directly or indirectly, any

person whose property and interests in property are blocked pursuant to E.O. 13664.

(b) The prohibitions in paragraph (a) of this section include prohibitions on the following transactions:

(1) The making of any contribution or provision of funds, goods, or services by, to, or for the benefit of any person whose property and interests in property are blocked pursuant to paragraph (a) of this section; and

(2) The receipt of any contribution or provision of funds, goods, or services from any person whose property and interests in property are blocked pursuant to paragraph (a) of this section.

(c) Unless authorized by this part or by a specific license expressly referring to this part, any dealing in securities (or evidence thereof) held within the possession or control of a U.S. person and either registered or inscribed in the name of, or known to be held for the benefit of, or issued by, any person whose property and interests in property are blocked pursuant to paragraph (a) of this section is prohibited. This prohibition includes the transfer (including the transfer on the books of any issuer or agent thereof), disposition, transportation, importation, exportation, or withdrawal of, or the endorsement or guaranty of signatures on, any securities on or after the effective date. This prohibition applies irrespective of the fact that at any time (whether prior to, on, or subsequent to the effective date) the registered or inscribed owner of any such securities may have or might appear to have assigned, transferred, or otherwise disposed of the securities.

(d) The prohibitions in paragraph (a) of this section apply except to the extent provided by statutes, or in regulations, rulings, instructions, orders, directives, or licenses that may be issued pursuant to this part, and notwithstanding any contract entered into or any license or permit granted prior to the effective date.

(e) All transactions prohibited pursuant to any Executive order issued after April 3, 2014 pursuant to the national emergency declared in E.O. 13664 of April 3, 2014 are prohibited pursuant to this part.

Note 1 to § 558.201. The names of persons designated or identified as blocked pursuant to E.O. 13664, or any further Executive orders issued pursuant to the national emergency declared therein, whose property and interests in property therefore are blocked pursuant to this section, are published in the **Federal Register** and incorporated into OFAC's Specially Designated Nationals and Blocked Persons List (SDN List) using the following identifiers: for E.O. 13664:

“[SOUTH SUDAN]”; and for any further Executive orders issued pursuant to the national emergency declared in E.O. 13664: using the identifier formulation “[SOUTH SUDAN–E.O.[E.O. number pursuant to which the person’s property and interests in property are blocked]].” The SDN List is accessible through the following page on OFAC’s website: www.treas.gov/sdn. Additional information pertaining to the SDN List can be found in appendix A to this chapter. See § 558.411 concerning entities that may not be listed on the SDN List but whose property and interests in property are nevertheless blocked pursuant to this section.

Note 2 to § 558.201. The International Emergency Economic Powers Act (50 U.S.C. 1701 *et seq.*), in section 203 (50 U.S.C. 1702), authorizes the blocking of property and interests in property of a person during the pendency of an investigation. The names of persons whose property and interests in property are blocked pending investigation pursuant to this section also are published in the **Federal Register** and incorporated into the SDN List using the following identifiers: for E.O. 13664: “[BPI–SOUTH SUDAN]”; for any further Executive orders issued pursuant to the national emergency declared in E.O. 13664: using the identifier formulation “[BPI–SOUTH SUDAN–E.O.[E.O. number pursuant to which the person’s property and interests in property are blocked pending investigation]].”

Note 3 to § 558.201. Sections 501.806 and 501.807 of this chapter describe the procedures to be followed by persons seeking, respectively, the unblocking of funds that they believe were blocked due to mistaken identity, or administrative reconsideration of their status as persons whose property and interests in property are blocked pursuant to this section.

§ 558.202 Effect of transfers violating the provisions of this part.

(a) Any transfer after the effective date that is in violation of any provision of this part or of any regulation, ruling, instruction, order, directive, or license issued pursuant to this part, and that involves any property or interest in property blocked pursuant to § 558.201, is null and void and shall not be the basis for the assertion or recognition of any interest in or right, remedy, power, or privilege with respect to such property or interest in property.

(b) No transfer before the effective date shall be the basis for the assertion or recognition of any right, remedy, power, or privilege with respect to, or any interest in, any property or interest in property blocked pursuant to § 558.201, unless the person who holds or maintains such property, prior to that date, had written notice of the transfer or by any written evidence had recognized such transfer.

(c) Unless otherwise provided, a license or other authorization issued by

OFAC before, during, or after a transfer shall validate such transfer or make it enforceable to the same extent that it would be valid or enforceable but for the provisions of this part and any regulation, ruling, instruction, order, directive, or license issued pursuant to this part.

(d) Transfers of property that otherwise would be null and void or unenforceable by virtue of the provisions of this section shall not be deemed to be null and void or unenforceable as to any person with whom such property is or was held or maintained (and as to such person only) in cases in which such person is able to establish to the satisfaction of OFAC each of the following:

(1) Such transfer did not represent a willful violation of the provisions of this part by the person with whom such property is or was held or maintained (and as to such person only);

(2) The person with whom such property is or was held or maintained did not have reasonable cause to know or suspect, in view of all the facts and circumstances known or available to such person, that such transfer required a license or authorization issued pursuant to this part and was not so licensed or authorized, or, if a license or authorization did purport to cover the transfer, that such license or authorization had been obtained by misrepresentation of a third party or withholding of material facts or was otherwise fraudulently obtained; and

(3) The person with whom such property is or was held or maintained filed with OFAC a report setting forth in full the circumstances relating to such transfer promptly upon discovery that:

(i) Such transfer was in violation of the provisions of this part or any regulation, ruling, instruction, order, directive, license, or other directive or authorization issued pursuant to this part;

(ii) Such transfer was not licensed or authorized by OFAC; or

(iii) If a license did purport to cover the transfer, such license had been obtained by misrepresentation of a third party or withholding of material facts or was otherwise fraudulently obtained.

(e) The filing of a report in accordance with the provisions of paragraph (d)(3) of this section shall not be deemed evidence that the terms of paragraphs (d)(1) and (2) of this section have been satisfied.

(f) Unless licensed pursuant to this part, any attachment, judgment, decree, lien, execution, garnishment, or other judicial process is null and void with respect to any property or interest in property blocked pursuant to § 558.201.

§ 558.203 Holding of funds in interest-bearing accounts; investment and reinvestment.

(a) Except as provided in paragraph (e) or (f) of this section, or as otherwise directed or authorized by OFAC, any U.S. person holding funds, such as currency, bank deposits, or liquidated financial obligations, subject to § 558.201 shall hold or place such funds in a blocked interest-bearing account located in the United States.

(b)(1) For the purposes of this section, the term *blocked interest-bearing account* means a blocked account:

(i) In a federally insured U.S. bank, thrift institution, or credit union, provided the funds are earning interest at rates that are commercially reasonable; or

(ii) With a broker or dealer registered with the Securities and Exchange Commission under the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*), provided the funds are invested in a money market fund or in U.S. Treasury bills.

(2) Funds held or placed in a blocked account pursuant to paragraph (a) of this section may not be invested in instruments the maturity of which exceeds 180 days.

(c) For the purposes of this section, a rate is commercially reasonable if it is the rate currently offered to other depositors on deposits or instruments of comparable size and maturity.

(d) For the purposes of this section, if interest is credited to a separate blocked account or subaccount, the name of the account party on each account must be the same.

(e) Blocked funds held in instruments the maturity of which exceeds 180 days at the time the funds become subject to § 558.201 may continue to be held until maturity in the original instrument, provided any interest, earnings, or other proceeds derived therefrom are paid into a blocked interest-bearing account in accordance with paragraph (a) or (f) of this section.

(f) Blocked funds held in accounts or instruments outside the United States at the time the funds become subject to § 558.201 may continue to be held in the same type of accounts or instruments, provided the funds earn interest at rates that are commercially reasonable.

(g) This section does not create an affirmative obligation for the holder of blocked tangible property, such as real or personal property, or of other blocked property, such as debt or equity securities, to sell or liquidate such property. However, OFAC may issue licenses permitting or directing such sales or liquidation in appropriate cases.

(h) Funds blocked pursuant to § 558.201 may not be held, invested, or reinvested in a manner that provides financial or economic benefit or access to any person whose property and interests in property are blocked pursuant to § 558.201, nor may their holder cooperate in or facilitate the pledging or other attempted use as collateral of blocked funds or other assets.

§ 558.204 Expenses of maintaining blocked tangible property; liquidation of blocked property.

(a) Except as otherwise authorized, and notwithstanding the existence of any rights or obligations conferred or imposed by any international agreement or contract entered into or any license or permit granted prior to the effective date, all expenses incident to the maintenance of tangible property blocked pursuant to § 558.201 shall be the responsibility of the owners or operators of such property, which expenses shall not be met from blocked funds.

(b) Property blocked pursuant to § 558.201 may, in the discretion of OFAC, be sold or liquidated and the net proceeds placed in a blocked interest-bearing account in the name of the owner of the property.

§ 558.205 Evasions; attempts; causing violations; conspiracies.

(a) Any transaction on or after the effective date that evades or avoids, has the purpose of evading or avoiding, causes a violation of, or attempts to violate any of the prohibitions set forth in this part is prohibited.

(b) Any conspiracy formed to violate the prohibitions set forth in this part is prohibited.

§ 558.206 Exempt transactions.

The prohibitions contained in this part do not apply to any transactions that are exempt pursuant to section 203(b) of the International Emergency Economic Powers Act (50 U.S.C. 1702(b)).

Subpart C—General Definitions

§ 558.300 Applicability of definitions.

The definitions in this subpart apply throughout the entire part.

§ 558.301 Blocked account; blocked property.

The terms *blocked account* and *blocked property* mean any account or property subject to the prohibitions in § 558.201 held in the name of a person whose property and interests in property are blocked pursuant to § 558.201, or in which such person has

an interest, and with respect to which payments, transfers, exportations, withdrawals, or other dealings may not be made or effected except pursuant to a license or other authorization from OFAC expressly authorizing such action.

Note 1 to § 558.301. See § 558.411 concerning the blocked status of property and interests in property of an entity that is directly or indirectly owned, whether individually or in the aggregate, 50 percent or more by one or more persons whose property and interests in property are blocked pursuant to § 558.201.

§ 558.302 Effective date.

(a) The term *effective date* refers to the effective date of the applicable prohibitions and directives contained in this part, and, with respect to a person whose property and interests in property are blocked pursuant to § 558.201, the earlier of the date of actual or constructive notice that such person's property and interests in property are blocked.

(b) For the purposes of this section, *constructive notice* is the date that a notice of the blocking of the relevant person's property and interests in property is published in the **Federal Register**.

§ 558.303 Entity.

The term *entity* means a partnership, association, trust, joint venture, corporation, group, subgroup, or other organization.

§ 558.304 Financial, material, logistical, or technological support.

The term *financial, material, logistical, or technological support* means any property, tangible or intangible, including currency, financial instruments, securities, or any other transmission of value; weapons or related materiel; chemical or biological agents; explosives; false documentation or identification; communications equipment; computers; electronic or other devices or equipment; technologies; lodging; safe houses; facilities; vehicles or other means of transportation; or goods. “Technologies” as used in this section means specific information necessary for the development, production, or use of a product, including related technical data such as blueprints, plans, diagrams, models, formulae, tables, engineering designs and specifications, manuals, or other recorded instructions.

§ 558.305 [Reserved]

§ 558.306 Interest.

Except as otherwise provided in this part, the term *interest*, when used with

respect to property (e.g., “an interest in property”), means an interest of any nature whatsoever, direct or indirect.

§ 558.307 Licenses; general and specific.

(a) Except as otherwise provided in this part, the term *license* means any license or authorization contained in or issued pursuant to this part.

(b) The term *general license* means any license or authorization the terms of which are set forth in subpart E of this part or made available on OFAC's website: www.treas.gov/ofac.

(c) The term *specific license* means any license or authorization issued pursuant to this part but not set forth in subpart E of this part or made available on OFAC's website: www.treas.gov/ofac.

Note 1 to § 558.307. See § 501.801 of this chapter on licensing procedures.

§ 558.308 OFAC.

The term *OFAC* means the Department of the Treasury's Office of Foreign Assets Control.

§ 558.309 Person.

The term *person* means an individual or entity.

§ 558.310 Property; property interest.

The terms *property* and *property interest* include money, checks, drafts, bullion, bank deposits, savings accounts, debts, indebtedness, obligations, notes, guarantees, debentures, stocks, bonds, coupons, any other financial instruments, bankers acceptances, mortgages, pledges, liens or other rights in the nature of security, warehouse receipts, bills of lading, trust receipts, bills of sale, any other evidences of title, ownership, or indebtedness, letters of credit and any documents relating to any rights or obligations thereunder, powers of attorney, goods, wares, merchandise, chattels, stocks on hand, ships, goods on ships, real estate mortgages, deeds of trust, vendors' sales agreements, land contracts, leaseholds, ground rents, real estate and any other interest therein, options, negotiable instruments, trade acceptances, royalties, book accounts, accounts payable, judgments, patents, trademarks or copyrights, insurance policies, safe deposit boxes and their contents, annuities, pooling agreements, services of any nature whatsoever, contracts of any nature whatsoever, and any other property, real, personal, or mixed, tangible or intangible, or interest or interests therein, present, future, or contingent.

§ 558.311 Transfer.

The term *transfer* means any actual or purported act or transaction, whether or

not evidenced by writing, and whether or not done or performed within the United States, the purpose, intent, or effect of which is to create, surrender, release, convey, transfer, or alter, directly or indirectly, any right, remedy, power, privilege, or interest with respect to any property. Without limitation on the foregoing, it shall include the making, execution, or delivery of any assignment, power, conveyance, check, declaration, deed, deed of trust, power of attorney, power of appointment, bill of sale, mortgage, receipt, agreement, contract, certificate, gift, sale, affidavit, or statement; the making of any payment; the setting off of any obligation or credit; the appointment of any agent, trustee, or fiduciary; the creation or transfer of any lien; the issuance, docketing, filing, or levy of or under any judgment, decree, attachment, injunction, execution, or other judicial or administrative process or order, or the service of any garnishment; the acquisition of any interest of any nature whatsoever by reason of a judgment or decree of any foreign country; the fulfillment of any condition; the exercise of any power of appointment, power of attorney, or other power; or the acquisition, disposition, transportation, importation, exportation, or withdrawal of any security.

§ 558.312 United States.

The term *United States* means the United States, its territories and possessions, and all areas under the jurisdiction or authority thereof.

§ 558.313 United States person; U.S. person.

The term *United States person* or *U.S. person* means any United States citizen, permanent resident alien, entity organized under the laws of the United States or any jurisdiction within the United States (including foreign branches), or any person in the United States.

§ 558.314 U.S. financial institution.

The term *U.S. financial institution* means any U.S. entity (including its foreign branches) that is engaged in the business of accepting deposits, making, granting, transferring, holding, or brokering loans or credits, purchasing or selling foreign exchange, securities, futures or options, or procuring purchasers and sellers thereof, as principal or agent. It includes depository institutions, banks, savings banks, money services businesses, operators of credit card systems, trust companies, insurance companies, securities brokers and dealers, futures

and options brokers and dealers, forward contract and foreign exchange merchants, securities and commodities exchanges, clearing corporations, investment companies, employee benefit plans, dealers in precious metals, stones, or jewels, and U.S. holding companies, U.S. affiliates, or U.S. subsidiaries of any of the foregoing. This term includes those branches, offices, and agencies of foreign financial institutions that are located in the United States, but not such institutions' foreign branches, offices, or agencies.

Subpart D—Interpretations

§ 558.401 Reference to amended sections.

(a) Reference to any section in this part is a reference to the same as currently amended, unless the reference includes a specific date. *See* 44 U.S.C. 1510.

(b) Reference to any regulation, ruling, instruction, order, directive, or license issued pursuant to this part is a reference to the same as currently amended unless otherwise specified.

§ 558.402 Effect of amendment.

Unless otherwise specifically provided, any amendment, modification, or revocation of any provision in or appendix to this part or chapter or of any regulation, ruling, instruction, order, directive, or license issued by OFAC does not affect any act done or omitted, or any civil or criminal proceeding commenced or pending, prior to such amendment, modification, or revocation. All penalties, forfeitures, and liabilities under any such regulation, ruling, instruction, order, directive, or license continue and may be enforced as if such amendment, modification, or revocation had not been made.

§ 558.403 Termination and acquisition of an interest in blocked property.

(a) Whenever a transaction licensed or authorized by or pursuant to this part results in the transfer of property (including any property interest) away from a person whose property and interests in property are blocked pursuant to § 558.201, such property shall no longer be deemed to be property blocked pursuant to § 558.201, unless there exists in the property another interest that is blocked pursuant to § 558.201, the transfer of which has not been effected pursuant to license or other authorization.

(b) Unless otherwise specifically provided in a license or authorization issued pursuant to this part, if property (including any property interest) is transferred or attempted to be transferred to a person whose property

and interests in property are blocked pursuant to § 558.201, such property shall be deemed to be property in which such person has an interest and therefore blocked.

§ 558.404 Transactions ordinarily incident to a licensed transaction.

(a) Any transaction ordinarily incident to a licensed transaction and necessary to give effect thereto is also authorized, except:

(1) An ordinarily incident transaction, not explicitly authorized within the terms of the license, by or with a person whose property and interests in property are blocked pursuant to § 558.201; or

(2) An ordinarily incident transaction, not explicitly authorized within the terms of the license, involving a debit to a blocked account or a transfer of blocked property.

(b) For example, a license authorizing a person to complete a securities sale involving Company A, whose property and interests in property are blocked pursuant to § 558.201, also authorizes other persons to engage in activities that are ordinarily incident and necessary to complete the sale, including transactions by the buyer, broker, transfer agents, and banks, provided that such other persons are not themselves persons whose property and interests in property are blocked pursuant to § 558.201.

§ 558.405 Provision and receipt of services.

(a) The prohibitions contained in § 558.201 apply to services performed in the United States or by U.S. persons, wherever located:

(1) On behalf of or for the benefit of any person whose property and interests in property are blocked pursuant to § 558.201; or

(2) With respect to property interests of any person whose property and interests in property are blocked pursuant to § 558.201.

(b) The prohibitions on transactions contained in § 558.201 apply to services received in the United States or by U.S. persons, wherever located, where the service is performed by, or at the direction of, a person whose property and interests in property are blocked pursuant to § 558.201.

(c) For example, U.S. persons may not, except as authorized by or pursuant to this part, provide legal, accounting, financial, brokering, freight forwarding, transportation, public relations, or other services to any person whose property and interests in property are blocked pursuant to § 558.201, or negotiate with or enter into contracts signed by a

person whose property and interests in property are blocked pursuant to § 558.201.

Note 1 to § 558.405. See §§ 558.507 and 558.509 for general licenses authorizing the provision of certain legal and emergency medical services.

§ 558.406 Offshore transactions involving blocked property.

The prohibitions in § 558.201 on transactions or dealings involving blocked property, as defined in § 558.301, apply to transactions by any U.S. person in a location outside the United States.

§ 558.407 Payments from blocked accounts to satisfy obligations prohibited.

Pursuant to § 558.201, no debits may be made to a blocked account to pay obligations to U.S. persons or other persons, except as authorized by or pursuant to this part.

Note 1 to § 558.407. See also § 558.502(e), which provides that no license or other authorization contained in or issued pursuant to this part authorizes transfers of or payments from blocked property or debits to blocked accounts unless the license or other authorization explicitly authorizes the transfer of or payment from blocked property or the debit to a blocked account.

§ 558.408 Charitable contributions.

Unless specifically authorized by OFAC pursuant to this part, no charitable contribution of funds, goods, services, or technology, including contributions to relieve human suffering, such as food, clothing, or medicine, may be made by, to, or for the benefit of, or received from, a person whose property and interests in property are blocked pursuant to § 558.201. For the purposes of this part, a contribution is made by, to, or for the benefit of, or received from, a person whose property and interests in property are blocked pursuant to § 558.201 if made by, to, or in the name of, or received from or in the name of, such a person; if made by, to, or in the name of, or received from or in the name of, an entity or individual acting for or on behalf of, or owned or controlled by, such a person; or if made in an attempt to violate, to evade, or to avoid the bar on the provision of contributions by, to, or for the benefit of such a person, or the receipt of contributions from such a person.

§ 558.409 Credit extended and cards issued by financial institutions to a person whose property and interests in property are blocked.

The prohibition in § 558.201 on dealing in property subject to that section prohibits U.S. financial

institutions from performing under any existing credit agreements, including charge cards, debit cards, or other credit facilities issued by a financial institution to a person whose property and interests in property are blocked pursuant to § 558.201.

§ 558.410 Setoffs prohibited.

A setoff against blocked property (including a blocked account), whether by a U.S. financial institution or other U.S. person, is a prohibited transfer under § 558.201 if effected after the effective date.

§ 558.411 Entities owned by one or more persons whose property and interests in property are blocked.

Persons whose property and interests in property are blocked pursuant to § 558.201 have an interest in all property and interests in property of an entity in which such persons directly or indirectly own, whether individually or in the aggregate, a 50 percent or greater interest. The property and interests in property of such an entity, therefore, are blocked, and such an entity is a person whose property and interests in property are blocked pursuant to § 558.201, regardless of whether the name of the entity is incorporated into OFAC's Specially Designated Nationals and Blocked Persons List (SDN List).

Subpart E—Licenses, Authorizations, and Statements of Licensing Policy

§ 558.501 General and specific licensing procedures.

For provisions relating to licensing procedures, see part 501, subpart E, of this chapter. Licensing actions taken pursuant to part 501 of this chapter with respect to the prohibitions contained in this part are considered actions taken pursuant to this part. General licenses and statements of licensing policy relating to this part also may be available through the South Sudan-related sanctions page on OFAC's website: www.treas.gov/ofac.

§ 558.502 Effect of license or other authorization.

(a) No license or other authorization contained in this part, or otherwise issued by OFAC, authorizes or validates any transaction effected prior to the issuance of such license or other authorization, unless specifically provided in such license or authorization.

(b) No regulation, ruling, instruction, order, directive, or license authorizes any transaction prohibited under this part unless the regulation, ruling, instruction, order, directive, or license is issued by OFAC and specifically

refers to this part. No regulation, ruling, instruction, order, directive, or license referring to this part shall be deemed to authorize any transaction prohibited by any other part of this chapter unless the regulation, ruling, instruction, order, directive, or license specifically refers to such part.

(c) Any regulation, ruling, instruction, order, directive, or license authorizing any transaction prohibited under this part has the effect of removing a prohibition contained in this part from the transaction, but only to the extent specifically stated by its terms. Unless the regulation, ruling, instruction, order, directive, or license otherwise specifies, such an authorization does not create any right, duty, obligation, claim, or interest in, or with respect to, any property that would not otherwise exist under ordinary principles of law.

(d) Nothing contained in this part shall be construed to supersede the requirements established under any other provision of law or to relieve a person from any requirement to obtain a license or other authorization from another department or agency of the U.S. government in compliance with applicable laws and regulations subject to the jurisdiction of that department or agency. For example, exports of goods, services, or technical data that are not prohibited by this part or that do not require a license by OFAC nevertheless may require authorization by the U.S. Department of Commerce, the U.S. Department of State, or other agencies of the U.S. government.

(e) No license or other authorization contained in or issued pursuant to this part authorizes transfers of or payments from blocked property or debits to blocked accounts unless the license or other authorization explicitly authorizes the transfer of or payment from blocked property or the debit to a blocked account.

(f) Any payment relating to a transaction authorized in or pursuant to this part that is routed through the U.S. financial system should reference the relevant OFAC general or specific license authorizing the payment to avoid the blocking or rejection of the transfer.

§ 558.503 Exclusion from licenses.

OFAC reserves the right to exclude any person, property, transaction, or class thereof from the operation of any license or from the privileges conferred by any license. OFAC also reserves the right to restrict the applicability of any license to particular persons, property, transactions, or classes thereof. Such actions are binding upon actual or

constructive notice of the exclusions or restrictions.

§ 558.504 Payments and transfers to blocked accounts in U.S. financial institutions.

Any payment of funds or transfer of credit in which a person whose property and interests in property are blocked pursuant to § 558.201 has any interest that comes within the possession or control of a U.S. financial institution must be blocked in an account on the books of that financial institution. A transfer of funds or credit by a U.S. financial institution between blocked accounts in its branches or offices is authorized, provided that no transfer is made from an account within the United States to an account held outside the United States, and further provided that a transfer from a blocked account may be made only to another blocked account held in the same name.

Note 1 to § 558.504. See § 501.603 of this chapter for mandatory reporting requirements regarding financial transfers. See also § 558.203 concerning the obligation to hold blocked funds in interest-bearing accounts.

§ 558.505 Entries in certain accounts for normal service charges.

(a) A U.S. financial institution is authorized to debit any blocked account held at that financial institution in payment or reimbursement for normal service charges owed it by the owner of that blocked account.

(b) As used in this section, the term *normal service charges* shall include charges in payment or reimbursement for interest due; cable, telegraph, internet, or telephone charges; postage costs; custody fees; small adjustment charges to correct bookkeeping errors; and, but not by way of limitation, minimum balance charges, notary and protest fees, and charges for reference books, photocopies, credit reports, transcripts of statements, registered mail, insurance, stationery and supplies, and other similar items.

§ 558.506 Investment and reinvestment of certain funds.

Subject to the requirements of § 558.203, U.S. financial institutions are authorized to invest and reinvest assets blocked pursuant to § 558.201, subject to the following conditions:

(a) The assets representing such investments and reinvestments are credited to a blocked account or subaccount that is held in the same name at the same U.S. financial institution, or within the possession or control of a U.S. person, but funds shall not be transferred outside the United States for this purpose;

(b) The proceeds of such investments and reinvestments shall not be credited to a blocked account or subaccount under any name or designation that differs from the name or designation of the specific blocked account or subaccount in which such funds or securities were held; and

(c) No immediate financial or economic benefit accrues (e.g., through pledging or other use) to a person whose property and interests in property are blocked pursuant to § 558.201.

§ 558.507 Provision of certain legal services.

(a) The provision of the following legal services to or on behalf of persons whose property and interests in property are blocked pursuant to § 558.201 is authorized, provided that any receipt of payment of professional fees and reimbursement of incurred expenses must be authorized pursuant to § 558.508, which authorizes certain payments for legal services from funds originating outside the United States; via specific license; or otherwise pursuant to this part:

(1) Provision of legal advice and counseling on the requirements of and compliance with the laws of the United States or any jurisdiction within the United States, provided that such advice and counseling are not provided to facilitate transactions in violation of this part;

(2) Representation of persons named as defendants in or otherwise made parties to legal, arbitration, or administrative proceedings before any U.S. federal, state, or local court or agency;

(3) Initiation and conduct of legal, arbitration, or administrative proceedings before any U.S. federal, state, or local court or agency;

(4) Representation of persons before any U.S. federal, state, or local court or agency with respect to the imposition, administration, or enforcement of U.S. sanctions against such persons; and

(5) Provision of legal services in any other context in which prevailing U.S. law requires access to legal counsel at public expense.

(b) The provision of any other legal services to or on behalf of persons whose property and interests in property are blocked pursuant to § 558.201, not otherwise authorized in this part, requires the issuance of a specific license.

(c) U.S. persons do not need to obtain specific authorization to provide related services, such as making filings and providing other administrative services, that are ordinarily incident to the provision of services authorized by

paragraph (a) of this section.

Additionally, U.S. persons who provide services authorized by paragraph (a) of this section do not need to obtain specific authorization to contract for related services that are ordinarily incident to the provision of those legal services, such as those provided by private investigators or expert witnesses, or to pay for such services. See § 558.404.

(d) Entry into a settlement agreement or the enforcement of any lien, judgment, arbitral award, decree, or other order through execution, garnishment, or other judicial process purporting to transfer or otherwise alter or affect property or interests in property blocked pursuant to § 558.201 is prohibited unless licensed pursuant to this part.

Note 1 to § 558.507. Pursuant to part 501, subpart E, of this chapter, U.S. persons seeking administrative reconsideration or judicial review of their designation or the blocking of their property and interests in property may apply for a specific license from OFAC to authorize the release of certain blocked funds for the payment of professional fees and reimbursement of incurred expenses for the provision of such legal services where alternative funding sources are not available.

§ 558.508 Payments for legal services from funds originating outside the United States.

(a) *Professional fees and incurred expenses.* (1) Receipt of payment of professional fees and reimbursement of incurred expenses for the provision of legal services authorized pursuant to § 558.507(a) to or on behalf of any person whose property and interests in property are blocked pursuant to § 558.201, is authorized from funds originating outside the United States, provided that the funds do not originate from:

(i) A source within the United States;

(ii) Any source, wherever located, within the possession or control of a U.S. person; or

(iii) Any individual or entity, other than the person on whose behalf the legal services authorized pursuant to § 558.507(a) are to be provided, whose property and interests in property are blocked pursuant to any part of this chapter or any Executive order or statute.

(2) Nothing in this paragraph (a) authorizes payments for legal services using funds in which any other person whose property and interests in property are blocked pursuant to § 558.201, any other part of this chapter, or any Executive order or statute has an interest.

(b) *Reports.* (1) U.S. persons who receive payments pursuant to paragraph

(a) of this section must submit annual reports no later than 30 days following the end of the calendar year during which the payments were received providing information on the funds received. Such reports shall specify:

(i) The individual or entity from whom the funds originated and the amount of funds received; and

(ii) If applicable:

(A) The names of any individuals or entities providing related services to the U.S. person receiving payment in connection with authorized legal services, such as private investigators or expert witnesses;

(B) A general description of the services provided; and

(C) The amount of funds paid in connection with such services.

(2) The reports, which must reference this section, are to be submitted to OFAC using one of the following methods:

(i) Email (preferred method):

OFACReport@treasury.gov; or

(ii) U.S. mail: OFAC Regulations Reports, Office of Foreign Assets Control, U.S. Department of the Treasury, 1500 Pennsylvania Avenue NW, Freedman's Bank Building, Washington, DC 20220.

§ 558.509 Emergency medical services.

The provision and receipt of unscheduled emergency medical services that are prohibited by this part are authorized.

§ 558.510 Official business of the United States government.

All transactions prohibited by this part that are for the conduct of the official business of the United States government by employees, grantees, or contractors thereof are authorized.

§ 558.511 Official business of certain international organizations and entities.

All transactions prohibited by this part that are for the conduct of the official business of the following entities by employees, grantees, or contractors thereof are authorized:

(a) The United Nations, including its Programmes, Funds, and Other Entities and Bodies, as well as its Specialized Agencies and Related Organizations;

(b) The International Centre for Settlement of Investment Disputes (ICSID) and the Multilateral Investment Guarantee Agency (MIGA);

(c) The African Development Bank Group, the Asian Development Bank, the European Bank for Reconstruction and Development, and the Inter-American Development Bank Group (IDB Group), including any fund entity administered or established by any of the foregoing;

(d) The International Committee of the Red Cross and the International Federation of Red Cross and Red Crescent Societies; and

(e) The Global Fund to Fight AIDS, Tuberculosis, and Malaria and Gavi, the Vaccine Alliance.

§ 558.512 Certain transactions in support of nongovernmental organizations' activities.

(a) Except as provided in paragraph (c) of this section, all transactions prohibited by this part that are ordinarily incident and necessary to the activities described in paragraph (b) of this section by a nongovernmental organization are authorized, provided that the nongovernmental organization is not a person whose property or interests in property are blocked pursuant to this part.

(b) The activities referenced in paragraph (a) of this section are non-commercial activities designed to directly benefit the civilian population that fall into one of the following categories:

(1) Activities to support humanitarian projects to meet basic human needs, including disaster, drought, or flood relief; food, nutrition, or medicine distribution; the provision of health services; assistance for vulnerable or displaced populations, including individuals with disabilities and the elderly; and environmental programs;

(2) Activities to support democracy building, including activities to support rule of law, citizen participation, government accountability and transparency, human rights and fundamental freedoms, access to information, and civil society development projects;

(3) Activities to support education, including combating illiteracy, increasing access to education, international exchanges, and assisting education reform projects;

(4) Activities to support non-commercial development projects directly benefiting civilians, including those related to health, food security, and water and sanitation;

(5) Activities to support environmental and natural resource protection, including the preservation and protection of threatened or endangered species, responsible and transparent management of natural resources, and the remediation of pollution or other environmental damage; and

(6) Activities to support disarmament, demobilization, and reintegration (DDR) programs and peacebuilding, conflict prevention, and conflict resolution programs.

(c) This section does not authorize funds transfers initiated or processed with knowledge or reason to know that the intended beneficiary of such transfers is a person blocked pursuant to this part, other than for the purpose of effecting the payment of taxes, fees, or import duties, or the purchase or receipt of permits, licenses, or public utility services.

(d) Specific licenses may be issued on a case-by-case basis to authorize nongovernmental or other entities to engage in other activities designed to directly benefit the civilian population, including support for the removal of landmines and economic development projects directly benefiting the civilian population.

Note 1 to § 558.512. This section does not relieve any person authorized thereunder from complying with any other applicable laws or regulations.

§ 558.513 Transactions related to the provision of agricultural commodities, medicine, medical devices, replacement parts and components, or software updates for personal, non-commercial use.

(a) All transactions prohibited by this part that are related to the provision, directly or indirectly, of agricultural commodities, medicine, medical devices, replacement parts and components for medical devices, or software updates for medical devices to an individual whose property and interests in property are blocked pursuant to this part are authorized are authorized, provided the items are in quantities consistent with personal, non-commercial use.

(b) For the purposes of this section, agricultural commodities, medicine, and medical devices are defined as follows:

(1) *Agricultural commodities.* For the purposes of this section, agricultural commodities are:

(i) Products that fall within the term "agricultural commodity" as defined in section 102 of the Agricultural Trade Act of 1978 (7 U.S.C. 5602); and

(ii) That are intended for ultimate use as:

(A) Food for humans (including raw, processed, and packaged foods; live animals; vitamins and minerals; food additives or supplements; and bottled drinking water) or animals (including animal feeds);

(B) Seeds for food crops;

(C) Fertilizers or organic fertilizers; or

(D) Reproductive materials (such as live animals, fertilized eggs, embryos, and semen) for the production of food animals.

(2) *Medicine.* For the purposes of this section, medicine is an item that falls within the definition of the term "drug"

in section 201 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321).

(3) *Medical devices.* For the purposes of this section, a medical device is an item that falls within the definition of “device” in section 201 of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 321).

Note 1 to § 558.513. This section does not relieve any person authorized thereunder from complying with any other applicable laws or regulations.

Subpart F—Reports

§ 558.601 Records and reports.

For provisions relating to required records and reports, see part 501, subpart C, of this chapter. Recordkeeping and reporting requirements imposed by part 501 of this chapter with respect to the prohibitions contained in this part are considered requirements arising pursuant to this part.

Subpart G—Penalties and Findings of Violation

§ 558.701 Penalties.

(a) Section 206 of the International Emergency Economic Powers Act (50 U.S.C. 1705) (IEEPA) is applicable to violations of the provisions of any regulation, ruling, instruction, order, directive, or license issued by or pursuant to the direction or authorization of the Secretary of the Treasury pursuant to this part or otherwise under IEEPA.

(1) A civil penalty not to exceed the amount set forth in section 206 of IEEPA may be imposed on any person who violates, attempts to violate, conspires to violate, or causes a violation of any regulation, ruling, instruction, order, directive, license, or prohibition issued under IEEPA.

(2) IEEPA provides for a maximum civil penalty not to exceed the greater of \$356,579 or an amount that is twice the amount of the transaction that is the basis of the violation with respect to which the penalty is imposed.

(3) A person who willfully commits, willfully attempts to commit, willfully conspires to commit, or aids or abets in the commission of a violation of any regulation, ruling, instruction, order, directive, license, or prohibition may, upon conviction, be fined not more than \$1,000,000, or if a natural person, be imprisoned for not more than 20 years, or both.

(b)(1) The civil penalties provided in IEEPA are subject to adjustment pursuant to the Federal Civil Penalties Inflation Adjustment Act of 1990 (Pub.

L. 101–410, as amended, 28 U.S.C. 2461 note).

(2) The criminal penalties provided in IEEPA are subject to adjustment pursuant to 18 U.S.C. 3571.

(c) Pursuant to 18 U.S.C. 1001, whoever, in any matter within the jurisdiction of the executive, legislative, or judicial branch of the government of the United States, knowingly and willfully falsifies, conceals, or covers up by any trick, scheme, or device a material fact; or makes any materially false, fictitious, or fraudulent statement or representation; or makes or uses any false writing or document knowing the same to contain any materially false, fictitious, or fraudulent statement or entry shall be fined under title 18, United States Code, imprisoned, or both.

(d) Violations of this part may also be subject to other applicable laws.

§ 558.702 Pre-Penalty Notice; settlement.

(a) *When required.* If OFAC has reason to believe that there has occurred a violation of any provision of this part or a violation of the provisions of any regulation, ruling, instruction, order, directive, or license issued by or pursuant to the direction or authorization of the Secretary of the Treasury pursuant to this part or otherwise under the International Emergency Economic Powers Act (50 U.S.C. 1701 *et seq.*) and determines that a civil monetary penalty is warranted, OFAC will issue a Pre-Penalty Notice informing the alleged violator of the agency’s intent to impose a monetary penalty. A Pre-Penalty Notice shall be in writing. The Pre-Penalty Notice may be issued whether or not another agency has taken any action with respect to the matter. For a description of the contents of a Pre-Penalty Notice, see appendix A to part 501 of this chapter.

(b) *Response—(1) Right to respond.* An alleged violator has the right to respond to a Pre-Penalty Notice by making a written presentation to OFAC. For a description of the information that should be included in such a response, see appendix A to part 501 of this chapter.

(2) *Deadline for response.* A response to a Pre-Penalty Notice must be made within 30 days as set forth in paragraphs (b)(2)(i) and (ii) of this section. The failure to submit a response within 30 days shall be deemed to be a waiver of the right to respond.

(i) *Computation of time for response.* A response to a Pre-Penalty Notice must be postmarked or date-stamped by the U.S. Postal Service (or foreign postal service, if mailed abroad) or courier service provider (if transmitted to OFAC

by courier), or dated if sent by email, on or before the 30th day after the postmark date on the envelope in which the Pre-Penalty Notice was mailed or date the Pre-Penalty Notice was emailed. If the Pre-Penalty Notice was personally delivered by a non-U.S. Postal Service agent authorized by OFAC, a response must be postmarked or date-stamped on or before the 30th day after the date of delivery.

(ii) *Extensions of time for response.* If a due date falls on a federal holiday or weekend, that due date is extended to include the following business day. Any other extensions of time will be granted, at the discretion of OFAC, only upon specific request to OFAC.

(3) *Form and method of response.* A response to a Pre-Penalty Notice need not be in any particular form, but it must be typewritten and signed by the alleged violator or a representative thereof (electronic signature is acceptable), contain information sufficient to indicate that it is in response to the Pre-Penalty Notice, and include the OFAC identification number listed on the Pre-Penalty Notice. The response must be sent to OFAC’s Office of Compliance and Enforcement by mail or courier or email and must be postmarked or date-stamped in accordance with paragraph (b)(2) of this section.

(c) *Settlement.* Settlement discussion may be initiated by OFAC, the alleged violator, or the alleged violator’s authorized representative. For a description of practices with respect to settlement, see appendix A to part 501 of this chapter.

(d) *Guidelines.* Guidelines for the imposition or settlement of civil penalties by OFAC are contained in appendix A to part 501 of this chapter.

(e) *Representation.* A representative of the alleged violator may act on behalf of the alleged violator, but any oral communication with OFAC prior to a written submission regarding the specific allegations contained in the Pre-Penalty Notice must be preceded by a written letter of representation, unless the Pre-Penalty Notice was served upon the alleged violator in care of the representative.

§ 558.703 Penalty imposition.

If, after considering any written response to the Pre-Penalty Notice and any relevant facts, OFAC determines that there was a violation by the alleged violator named in the Pre-Penalty Notice and that a civil monetary penalty is appropriate, OFAC may issue a Penalty Notice to the violator containing a determination of the violation and the imposition of the monetary penalty. For

additional details concerning issuance of a Penalty Notice, see appendix A to part 501 of this chapter. The issuance of the Penalty Notice shall constitute final agency action. The violator has the right to seek judicial review of that final agency action in federal district court.

§ 558.704 Administrative collection; referral to United States Department of Justice.

In the event that the violator does not pay the penalty imposed pursuant to this part or make payment arrangements acceptable to OFAC, the matter may be referred for administrative collection measures by the Department of the Treasury or to the United States Department of Justice for appropriate action to recover the penalty in a civil suit in a federal district court.

§ 558.705 Findings of Violation.

(a) *When issued.* (1) OFAC may issue an initial Finding of Violation that identifies a violation if OFAC:

(i) Determines that there has occurred a violation of any provision of this part, or a violation of the provisions of any regulation, ruling, instruction, order, directive, or license issued by or pursuant to the direction or authorization of the Secretary of the Treasury pursuant to this part or otherwise under the International Emergency Economic Powers Act (50 U.S.C. 1701 *et seq.*);

(ii) Considers it important to document the occurrence of a violation; and

(iii) Based on the Guidelines contained in appendix A to part 501 of this chapter, concludes that an administrative response is warranted but that a civil monetary penalty is not the most appropriate response.

(2) An initial Finding of Violation shall be in writing and may be issued whether or not another agency has taken any action with respect to the matter. For additional details concerning issuance of a Finding of Violation, see appendix A to part 501 of this chapter.

(b) *Response*—(1) *Right to respond.* An alleged violator has the right to contest an initial Finding of Violation by providing a written response to OFAC.

(2) *Deadline for response; default determination.* A response to an initial Finding of Violation must be made within 30 days as set forth in paragraphs (b)(2)(i) and (ii) of this section. The failure to submit a response within 30 days shall be deemed to be a waiver of the right to respond, and the initial Finding of Violation will become final and will constitute final agency action. The violator has the right to seek

judicial review of that final agency action in federal district court.

(i) *Computation of time for response.*

A response to an initial Finding of Violation must be postmarked or date-stamped by the U.S. Postal Service (or foreign postal service, if mailed abroad) or courier service provider (if transmitted to OFAC by courier), or dated if sent by email, on or before the 30th day after the postmark date on the envelope in which the initial Finding of Violation was served or date the Finding of Violation was sent by email. If the initial Finding of Violation was personally delivered by a non-U.S. Postal Service agent authorized by OFAC, a response must be postmarked or date-stamped on or before the 30th day after the date of delivery.

(ii) *Extensions of time for response.* If a due date falls on a federal holiday or weekend, that due date is extended to include the following business day. Any other extensions of time will be granted, at the discretion of OFAC, only upon specific request to OFAC.

(3) *Form and method of response.* A response to an initial Finding of Violation need not be in any particular form, but it must be typewritten and signed by the alleged violator or a representative thereof (electronic signature is acceptable), contain information sufficient to indicate that it is in response to the initial Finding of Violation, and include the OFAC identification number listed on the initial Finding of Violation. The response must be sent to OFAC's Office of Compliance and Enforcement by mail or courier or email and must be postmarked or date-stamped in accordance with paragraph (b)(2) of this section.

(4) *Information that should be included in response.* Any response should set forth in detail why the alleged violator either believes that a violation of the regulations did not occur and/or why a Finding of Violation is otherwise unwarranted under the circumstances, with reference to the General Factors Affecting Administrative Action set forth in the Guidelines contained in appendix A to part 501 of this chapter. The response should include all documentary or other evidence available to the alleged violator that supports the arguments set forth in the response. OFAC will consider all relevant materials submitted in the response.

(c) *Determination*—(1) *Determination that a Finding of Violation is warranted.* If, after considering the response, OFAC determines that a final Finding of Violation should be issued, OFAC will issue a final Finding of Violation that

will inform the violator of its decision. A final Finding of Violation shall constitute final agency action. The violator has the right to seek judicial review of that final agency action in federal district court.

(2) *Determination that a Finding of Violation is not warranted.* If, after considering the response, OFAC determines a Finding of Violation is not warranted, then OFAC will inform the alleged violator of its decision not to issue a final Finding of Violation.

Note 1 to paragraph (c)(2). A determination by OFAC that a final Finding of Violation is not warranted does not preclude OFAC from pursuing other enforcement actions consistent with the Guidelines contained in appendix A to part 501 of this chapter.

(d) *Representation.* A representative of the alleged violator may act on behalf of the alleged violator, but any oral communication with OFAC prior to a written submission regarding the specific alleged violations contained in the initial Finding of Violation must be preceded by a written letter of representation, unless the initial Finding of Violation was served upon the alleged violator in care of the representative.

Subpart H—Procedures

§ 558.801 Procedures.

For license application procedures and procedures relating to amendments, modifications, or revocations of licenses; administrative decisions; rulemaking; and requests for documents pursuant to the Freedom of Information and Privacy Acts (5 U.S.C. 552 and 552a), see part 501, subpart E, of this chapter.

§ 558.802 Delegation of certain authorities of the Secretary of the Treasury.

Any action that the Secretary of the Treasury is authorized to take pursuant to E.O. 13664 of April 3, 2014, and any further Executive orders relating to the national emergency declared therein, may be taken by the Director of OFAC or by any other person to whom the Secretary of the Treasury has delegated authority so to act.

Subpart I—Paperwork Reduction Act

§ 558.901 Paperwork Reduction Act notice.

For approval by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3507) of information collections relating to recordkeeping and reporting requirements, licensing procedures, and other procedures, see § 501.901 of this chapter. 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 OMB.

Andrea M. Gacki,

Director, Office of Foreign Assets Control.

[FR Doc. 2023–10427 Filed 5–17–23; 8:45 am]

BILLING CODE 4810–AL–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2023–0009]

RIN 1625–AA00

Safety Zone; Chinese Harbor; Santa Cruz Island, California

AGENCY: Coast Guard, Department of Homeland Security (DHS).

ACTION: Temporary final rule.

SUMMARY: The U.S. Coast Guard is establishing a temporary safety zone for the navigable waters in Chinese Harbor of Santa Cruz Island, California. This safety zone is needed to protect personnel, vessels, and the marine environment from potential hazards created by ongoing salvage operations relating to the December 2022 grounding of a 60-foot fishing vessel in Chinese Harbor. Entry of persons or vessels into this safety zone is prohibited unless specifically authorized by the Captain of the Port (COTP), Los Angeles—Long Beach, or their designated representative.

DATES: This rule is effective without actual notice from May 18, 2023, until May 25, 2023. For the purposes of enforcement, actual notice will be used from May 15, 2023, until May 18, 2023.

ADDRESSES: To view documents mentioned in this preamble as being available in the docket, go to <https://www.regulations.gov>, type USCG–2023–0009 in the “SEARCH” box and click “SEARCH.” Click on Open Docket Folder on the line associated with this rule.

FOR FURTHER INFORMATION CONTACT: If you have questions about this rule, call or email LCDR Maria Wiener, Waterways Management, U.S. Coast Guard Sector Los Angeles—Long Beach; telephone (310) 357–1603, email D11-SMB-SectorLALB-WWM@uscg.mil.

SUPPLEMENTARY INFORMATION:

I. Table of Abbreviations

CFR Code of Federal Regulations

DHS Department of Homeland Security

E.O. Executive order
FR Federal Register
LLNR Light List Number
NPRM Notice of proposed rulemaking
Pub. L. Public Law
§ 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) because it is impracticable. This is a response to a vessel grounding and immediate action is needed to respond to potential safety hazards associated with vessel salvage operations. It is impracticable to publish an NPRM because we must establish this safety zone by May 15, 2023.

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 public interest because immediate action is needed to ensure the safety of persons, vessels, and the marine environment in the vicinity of Chinese Harbor during vessel salvage operations.

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) and 46 U.S.C. 70011(b)(3). The Captain of the Port (COTP), Los Angeles—Long Beach has determined that potential hazards associated with salvage operations starting May 15, 2023, will be a safety concern for anyone within a 500-yard radius of the operations in Chinese Harbor. This rule is needed to protect personnel, vessels, and the marine environment in the navigable waters within the safety zone while salvage operations take place in the vicinity of Chinese Harbor.

IV. Discussion of the Rule

This rule establishes a safety zone from May 15, 2023, until May 25, 2023. The safety zone will cover all navigable waters from the surface to the sea floor in and around the M/V DANNY C (Official Number 506332) and extending

out along a 500-yard radius from the vessel’s location while it is in Chinese Harbor. These coordinates are based on North American Datum of 1983. No vessel or person will be permitted to enter the safety zone without obtaining permission from the COTP or his designated representative. Sector Los Angeles—Long Beach may be contacted on VHF–FM Channel 16 or (310) 521–3801. The marine public will be notified of the safety zone via Broadcast Notice to Mariners.

If the COTP determines that the zone need not be enforced during this entire period, the Coast Guard will announce via Broadcast Notice to Mariners when the zone will no longer be subject to enforcement.

V. Regulatory Analyses

We developed this rule after considering numerous statutes and Executive orders (E.O.s) related to rulemaking. Below we summarize our analyses based on a number of these statutes and E.O.s, 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, location, duration, and time-of-year of the safety zone. Vessel traffic will be able to safely transit around this safety zone, which will impact a small, designated area of Chinese Harbor, Santa Cruz Island, CA. Moreover, the Coast Guard will issue Broadcast Notice to Mariners via VHF–FM marine channel 16 regarding the safety zone and 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 safety 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 call or email 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.

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 Management Directive 023–01, Rev. 1, associated implementing instructions, and 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 safety zone encompassing an area extending 500-yards out from a vessel engaged in salvage operations in vicinity of Chinese Harbor and will last only 10 days while salvage operations are ongoing. It is categorically excluded from further review under paragraph L60(c), in Appendix A, Table 1 of DHS Instruction Manual 023–001–01, 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. 01.3.

■ 2. Add § 165.T11–124 to read as follows:

§ 165.T11–124 Safety Zone; Chinese Harbor; Santa Cruz Island, California.

(a) *Location.* The following area is a safety zone: all navigable waters from the surface to the sea floor in and around the M/V DANNY C (Official Number 506332) and extending out along a 500-yard radius from that vessel while it is in Chinese Harbor. These coordinates are based on North American Datum of 1983.

(b) *Definitions.* As used in this section, *designated representative* means a Coast Guard Patrol Commander, including a Coast Guard coxswain, petty officer, or other officer operating a Coast Guard vessel and a Federal, State, and local officer designated by or assisting the Captain of the Port Los Angeles-Long Beach (COTP) in the enforcement of the safety zone.

(c) *Regulations.* (1) Under the general safety zone regulations in subpart C of this part, you may not enter the safety zone described in paragraph (a) of this section unless authorized by the COTP or the COTP's designated representative.

(2) To seek permission to enter, contact the COTP or the COTP's representative by hailing Coast Guard Sector Los Angeles—Long Beach on VHF–FM Channel 16 or calling at (310) 521–3801. Those in the safety zone must comply with all lawful orders or directions given to them by the COTP or the COTP's designated representative.

(d) *Enforcement period.* This section will be enforced from May 15, 2023, through May 25, 2023. The marine public will be notified of this safety zone via Broadcast Notice to Mariners. If the Captain of the Port determines that the zone need not be enforced during this entire period, the Coast Guard will announce via Broadcast Notice to Mariners when the zone will no longer be subject to enforcement.

Dated: May 15, 2023.

R.D. Manning,

Captain, U.S. Coast Guard, Captain of the Port, Los Angeles—Long Beach.

[FR Doc. 2023–10718 Filed 5–16–23; 11:15 am]

BILLING CODE 9110–04–P

DEPARTMENT OF THE INTERIOR**National Park Service****36 CFR Part 7**

[NPS–WASO–35108; PPNCNAMA00, PPMPAS1Z.Y00000, 233P103601]

RIN 1024–AE84

National Capital Region; Change of Address**AGENCY:** National Park Service, Interior.**ACTION:** Final rule.

SUMMARY: The National Park Service amends the special regulations for the National Capital Region to change the street address for the Division of Permits Management.

DATES: This rule is effective on May 18, 2023.

FOR FURTHER INFORMATION CONTACT:

Robbin Owen, Chief, Division of Permits Management, National Capital Region, National Park Service; phone: (202) 359–1459; email: robbin_owen@nps.gov. 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: This rule updates National Park Service (NPS) regulations at 36 CFR 7.96(g)(3) to reflect the new address of the Division of Permits Management for the National Mall and Memorial Parks. This change is needed to provide accurate information about where permits for demonstrations and special events within the National Capital Region may be obtained by the public. The Division of Permits Management relocated on February 27, 2023. The NPS has already notified the public of the address change on its website and through other means of communication.

Compliance With Other Laws, Executive Orders and Department Policy Regulatory Planning and Review (Executive Orders 12866 and 13563)

Executive Order 12866 provides that the Office of Information and Regulatory Affairs in the Office of Management and Budget will review all significant rules. The Office of Information and Regulatory Affairs has determined that this rule is not significant.

Executive Order 13563 reaffirms the principles of Executive Order 12866 while calling for improvements in the

Nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The Executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. Executive Order 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. The NPS has developed this rule in a manner consistent with these requirements.

Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*, generally requires Federal agencies to prepare a regulatory flexibility analysis for rules that are subject to the notice-and-comment rulemaking requirements under the Administrative Procedure Act (APA) if the rule would have a significant economic impact on a substantial number of small entities. *See* 5 U.S.C. 601–612. The NPS certifies that this final rule will not have a significant economic effect on a substantial number of small entities. This is a technical, non-substantive rule that updates the street address in Washington, DC, where the public may obtain permit applications for activities within the National Capital Region.

Congressional Review Act

This rule is not a major rule under 5 U.S.C. 804(2). This rule:

(a) Does not have an annual effect on the economy of \$100 million or more.

(b) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

(c) Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises.

Unfunded Mandates Reform Act

This rule will not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than \$100 million per year. The rule will not have a significant or unique effect on State, local, or tribal governments or the private sector. It addresses public use of national park lands and imposes no requirements on other agencies or governments. A statement containing the information

required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required.

Takings (Executive Order 12630)

This rule will not effect a taking of private property or otherwise have takings implications under Executive Order 12630. A takings implication assessment is not required.

Federalism (Executive Order 13132)

Under the criteria in section 1 of Executive Order 13132, the rule will not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement. A federalism summary impact statement is not required.

Civil Justice Reform (Executive Order 12988)

This rule complies with the requirements of Executive Order 12988. This rule:

(a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

(b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation With Indian Tribes (Executive Order 13175 and Department Policy)

The Department of the Interior strives to strengthen its government-to-government relationship with Indian Tribes through a commitment to consultation with Indian tribes and recognition of their right to self-governance and tribal sovereignty. The NPS has evaluated this rule under the criteria in Executive Order 13175 and under the Department's tribal consultation policy and has determined that tribal consultation is not required because the rule will have no substantial direct effect on federally recognized Indian tribes.

Paperwork Reduction Act

This rule does not contain information collection requirements, and a submission to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) is not required. The NPS 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.

National Environmental Policy Act (NEPA)

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the National Environmental Policy Act of 1969 (NEPA) is not required because this is a technical regulation. (For further information see 43 CFR 46.210(i).) We have also determined that the rule does not involve any of the extraordinary circumstances listed in 43 CFR 46.215 that would require further analysis under NEPA.

Effects on the Energy Supply (Executive Order 13211)

This rulemaking is not a significant energy action under the definition in Executive Order 13211; the rule is not likely to have a significant adverse effect on the supply, distribution, or use of energy, and the rule has not otherwise been designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action. A Statement of Energy Effects is not required.

Determination To Issue Final Rule Without the Opportunity for Public Comment and With Immediate Effective Date

The NPS recognizes that under 5 U.S.C. 553(b) and (c), notice of proposed rules ordinarily must be published in the **Federal Register** and the agency must give interested parties an opportunity to submit their views and comments. The NPS has determined under 5 U.S.C. 553(b) and 318 DM HB 5.3, however, that notice and public comment for this rule are not required. We find good cause to treat notice and comment as unnecessary because this rule simply updates the address of the Division of Permits Management that appears in NPS regulations to reflect the current address of the Division.

List of Subjects in 36 CFR Part 7

District of Columbia, National parks, Reporting and recordkeeping requirements.

In consideration of the foregoing, the National Park Service amends 36 CFR part 7 as follows:

PART 7—SPECIAL REGULATIONS, AREAS OF THE NATIONAL PARK SYSTEM

■ 1. The authority for part 7 continues to read as follows:

Authority: 54 U.S.C. 100101, 100751, 320102; Sec. 7.96 also issued under DC Code 10–137 and DC Code 50–2201.07.

■ 2. In § 7.96, amend paragraph (g)(3) by revising the first sentence to read as follows:

§ 7.96 National Capital Region.

* * * * *

(g) * * *

(3) *Permit applications.* Permit applications may be obtained at the Division of Permits Management, National Mall and Memorial Parks, 1100 Ohio Drive SW, Washington, DC 20024.

* * *

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Shannon Estenoz,

Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 2023–10377 Filed 5–17–23; 8:45 am]

BILLING CODE 4312–52–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2021–0612; FRL–10972–01–OCSPF]

D-Glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts; D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated, potassium salts; and D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts; Exemptions From the Requirement of a Tolerance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes exemptions from the requirement of a tolerance for residues of D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts; D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated, potassium salts; and D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts when used as inert ingredients (surfactants) pre- and post-harvest. Lamberti USA, Inc. submitted a petition to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), requesting establishment of exemptions from the requirement of a tolerance. This regulation eliminates the need to establish a maximum permissible level for residues of D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts; D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated,

potassium salts; and D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts, when used in accordance with the terms of these exemptions.

DATES: This regulation is effective May 18, 2023. Objections and requests for hearings must be received on or before July 17, 2023 and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The dockets for these actions, identified by docket identification (ID) number EPA–HQ–OPP–2021–0612, are available at <https://www.regulations.gov> or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room and the OPP docket is (202) 566–1744. Please review the visitor instructions and additional information about the docket available at <https://www.epa.gov/dockets>.

FOR FURTHER INFORMATION CONTACT: Charles Smith, Director, Registration Division (7505T), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; main telephone number: (202) 566–1030; email address: RDfRNotices@epa.gov.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of 40 CFR part 180 through the **Federal Register** Office's e-CFR site at <https://www.ecfr.gov/current/title-40/chapter-I/subchapter-E/part-180?toc=1>.

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a(g), any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA-HQ-OPP-2021-0612, in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before July 17, 2023. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA-HQ-OPP-2021-0612, by one of the following methods:

- **Federal eRulemaking Portal:** <https://www.regulations.gov>. Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.

- **Mail:** OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW, Washington, DC 20460-0001.

- **Hand Delivery:** To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at <https://www.epa.gov/dockets/where-send-comments-epa-dockets#express>.

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at <https://www.epa.gov/dockets>.

II. Petition for Exemption

In the **Federal Register** of June 22, 2022 (87 FR 37287) (FRL-9410-02-OCSP), EPA issued a document pursuant to FFDCA section 408, 21 U.S.C. 346a, announcing the filing of a pesticide petition (PP IN-11613) by Spring Regulatory Sciences, on behalf of Lamberti-USA, Inc. (Lamberti), 161 Washington Street, Conshohocken, PA 19428. The petition requested that 40 CFR 180.910 be amended by establishing exemptions from the requirement of a tolerance for residues of D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2585031-35-0); D-glucopyranose, oligomeric, maleates, C10-16-alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2587364-77-8); and D-glucopyranose, oligomeric, maleates, C9-11-branched and linear alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 1228577-37-4) when used as inert ingredients (surfactants) in pesticide formulations pre- and post-harvest. That document referenced a summary of the petition prepared by Lamberti, which is available in the docket at <https://www.regulations.gov>. There were no comments received in response to the notice of filing.

III. Inert Ingredient Definition

Inert ingredients are all ingredients that are not active ingredients as defined in 40 CFR 153.125 and include, but are not limited to, the following types of ingredients (except when they have a pesticidal efficacy of their own): solvents such as alcohols and hydrocarbons; surfactants such as polyoxyethylene polymers and fatty acids; carriers such as clay and diatomaceous earth; thickeners such as carrageenan and modified cellulose; wetting, spreading, and dispersing agents; propellants in aerosol dispensers; microencapsulating agents; and emulsifiers. The term “inert” is not intended to imply nontoxicity; the ingredient may or may not be chemically active. Generally, EPA has exempted inert ingredients from the requirement of a tolerance based on the low toxicity of the individual inert ingredients.

IV. Aggregate Risk Assessment and Determination of Safety

Section 408(c)(2)(A)(i) of FFDCA allows EPA to establish an exemption from the requirement for a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the tolerance is “safe.” Section 408(c)(2)(A)(ii) of FFDCA

defines “safe” to mean that “there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information.” This includes exposure through drinking water and in residential settings but does not include occupational exposure. When making a safety determination for an exemption from the requirement of a tolerance, FFDCA section 408(c)(2)(B) directs EPA to take into account the considerations in section 408(b)(2)(C) and (D). Section 408(b)(2)(C) of FFDCA requires EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance or exemption and to “ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue” Section 408(b)(2)(D) lists other factors for EPA’s consideration in making safety determinations, *e.g.*, the validity, completeness, and reliability of available data, nature of toxic effects, available information concerning the cumulative effects of the pesticide chemical and other substances with a common mechanism of toxicity, and available information concerning aggregate exposure levels to the pesticide chemical and other related substances, among other factors.

EPA establishes exemptions from the requirement of a tolerance only in those cases where it can be clearly demonstrated that the risks from aggregate exposure to pesticide chemical residues under reasonably foreseeable circumstances will pose no harm to human health. In order to determine the risks from aggregate exposure to pesticide inert ingredients, the Agency considers the toxicity of the inert in conjunction with possible exposure to residues of the inert ingredient through food, drinking water, and through other exposures that occur as a result of pesticide use in residential settings. If EPA is able to determine that a finite tolerance is not necessary to ensure that there is a reasonable certainty that no harm will result from aggregate exposure to the inert ingredient, an exemption from the requirement of a tolerance may be established.

Consistent with FFDCA section 408(c)(2)(A), and the factors specified in FFDCA section 408(c)(2)(B), EPA has reviewed the available scientific data and other relevant information in support of these actions. EPA has sufficient data to assess the hazards of and to make a determination on

aggregate exposure for D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts; D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated, potassium salts; and D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts, including exposure resulting from the exemptions established by this action. These three chemicals are potassium salts of alkyl (C8–C20) polyglucoside esters (AGEs) and are herein referred to as the AGE potassium salts. EPA's assessment of exposures and risks associated with the AGE potassium salts follows.

A. Toxicological Profile

EPA has evaluated the available toxicity data and considered their validity, completeness, and reliability as well as the relationship of the results of the studies to human risk. EPA has also considered available information concerning the variability of the sensitivities of major identifiable subgroups of consumers, including infants and children. Specific information on the studies received and the nature of the adverse effects caused by the AGE potassium salts as well as the no-observed-adverse-effect-level (NOAEL) and the lowest-observed-adverse-effect-level (LOAEL) from the toxicity studies are discussed in this unit.

The toxicological database of the AGE potassium salts is supported by data used for the Agency's 2015 evaluation of two AGE sodium salts and one AGE lactate (80 FR 31481, June 3, 2015). When EPA previously reviewed those AGEs, limited data were available, and the Agency determined that it would be appropriate to bridge to data for similar chemicals. EPA has determined that a similar approach is appropriate for the three AGE potassium salts because of the similarities in the manufacturing processes, functional groups/structure, composition, physical/chemical properties, and expected toxicity of these chemicals to those previously reviewed.

The AGEs are reaction products of glucose and fatty acids in which the alcohol moiety is attached to the polyglucoside by a β -glucosides linkage. Alkyl polyglucoside is the first degradation product in the biodegradation pathway of the AGEs, and toxicity data for alkyl polyglucoside are very similar for the different alcohol chain lengths in the range C8–C20. The toxicity profile of the AGE potassium salts is therefore based upon data considered in the previous risk assessment for AGE sodium salts and

AGE lactate where the alcohol component of the AGE substances is in the same C8–C20 range and is considered appropriate for read across purposes.

Specifically, EPA considered data for D-glucopyranose, oligomeric, 6-(dihydrogen 2-hydroxy-1,2,3-propanetricarboxylate), 1-(coco alkyl) ethers, sodium salts (CAS No. 151911–51–2); D-glucopyranose, oligomeric, 6-(hydrogen 2-sulfobutanedioate), 1-(coco alkyl) ethers, sodium salts (CAS No. 151911–53–4); D-glucopyranose, oligomeric, 6-[hydrogen (2R, 3R)-2,3-dihydroxybutanedioate], 1-(coco alkyl) ethers, sodium salts (CAS No. 151911–52–3); and D-Glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, sodium salts (CAS No. 1228577–41–0), as well as the metabolites disodium sulfosuccinate and other sulfosuccinates.

In acute studies, the oral lethal dose, LD₅₀ for the AGEs was >5,000 milligrams/kilogram (mg/kg). There is no available data regarding acute exposure via the dermal, eye or inhalation routes. Repeat dose studies were conducted with alkyl polyglucosides and organic acids (metabolites) in which no toxicity was seen at doses as high as 1,000 mg/kg/day. No fetal, parental, or reproductive toxicity was seen in a reproduction/developmental toxicity screening test up to 1,000 mg/kg/day. In addition, no evidence of neurotoxicity was seen in the database. Ames studies conducted with various AGE sodium salts were negative for mutagenicity, and there was no indication of carcinogenicity when the Agency evaluated the carcinogenic potential of AGEs by conducting a qualitative structure activity relationship (SAR) using the database, DEREK Nexus Version 2.0. No structural alerts were identified for carcinogenicity.

Specific information on the studies reviewed and the nature of the adverse effects caused by the AGEs can be found at <https://www.regulations.gov> in the documents “IN–11613; Alkyl (C8–C20) polyglucoside esters (AGEs) potassium salts. Human Health Risk Assessment and Ecological Effects Assessment to Support Inert Ingredient Approval for use in Pesticide Formulations” in docket ID number EPA–HQ–OPP–2021–0612, and “PC Codes 911028, 911029, 911030: Alkyl (C8–C20) polyglucoside Esters (AGEs); Human Health Risk Assessment and Ecological Effects Assessment to Support Proposed Exemption from the Requirement of a Tolerance When Used as Inert Ingredients in Pesticide Formulations”

in docket ID number EPA–HQ–OPP–2014–0678.

B. Toxicological Points of Departure/Levels of Concern

Once a pesticide's toxicological profile is determined, EPA identifies toxicological points of departure (POD) and levels of concern to use in evaluating the risk posed by human exposure to the pesticide. For hazards that have a threshold below which there is no appreciable risk, the toxicological POD is used as the basis for derivation of reference values for risk assessment. PODs are developed based on a careful analysis of the doses in each toxicological study to determine the dose at which no adverse effects are observed (the NOAEL) and the lowest dose at which adverse effects of concern are identified (the LOAEL). Uncertainty/safety factors are used in conjunction with the POD to calculate a safe exposure level—generally referred to as a population-adjusted dose (PAD) or a reference dose (RfD)—and a safe margin of exposure (MOE). For non-threshold risks, the Agency assumes that any amount of exposure will lead to some degree of risk. Thus, the Agency estimates risk in terms of the probability of an occurrence of the adverse effect expected in a lifetime. For more information on the general principles EPA uses in risk characterization and a complete description of the risk assessment process, see <https://www.epa.gov/pesticide-science-and-assessing-pesticide-risks/overview-risk-assessment-pesticide-program>.

The hazard profile of the AGE potassium salts is adequately defined. These salts are rapidly hydrolyzed in intestine and liver. The cleavage products, sugars, and long-chain alcohols enter the pathways of lipid and carbohydrate metabolism. Based on the low acute, subchronic, and developmental toxicity of AGEs, the body's ability to rapidly metabolize these substances, the expected metabolites being fatty acids and carbohydrates (which are normal constituents of the body), and the lack of observed adverse effects for repeat dose studies at the limit dose (1,000 mg/kg/day), no toxicological endpoint of concern or PODs were identified. Therefore, a qualitative risk assessment for the AGE potassium salts can be performed.

C. Exposure Assessment

1. *Dietary exposure from food and feed uses.* In evaluating dietary exposure to the AGE potassium salts, EPA considered exposure under the proposed exemptions from the

requirement of a tolerance. There are no other known food uses for these chemicals; therefore, EPA assessed the proposed dietary exposures from the AGE potassium salts in food as follows:

Dietary exposure (food and drinking water) to the AGE potassium salts may occur following ingestion of foods with residues from their use in accordance with these exemptions. However, a quantitative dietary exposure assessment was not conducted since a toxicological endpoint for risk assessment was not identified.

2. *From non-dietary exposure.* The term “residential exposure” is used in this document to refer to non-occupational, non-dietary exposure (e.g., textiles (clothing and diapers), carpets, swimming pools, and hard surface disinfection on walls, floors, tables). AGE potassium salts may be present in pesticide and non-pesticide products that may be used in and around the home, including personal care products such as antiperspirants, shampoos, conditioners, and moisturizers. However, a quantitative residential exposure assessment was not conducted since a toxicological endpoint for risk assessment was not identified.

3. *Cumulative effects from substances with a common mechanism of toxicity.* Section 408(b)(2)(D)(v) of FFDCA requires that, when considering whether to establish, modify, or revoke a tolerance, the Agency consider “available information” concerning the cumulative effects of a particular pesticide’s residues and “other substances that have a common mechanism of toxicity.”

Based on the lack of toxicity in the available database, EPA has not found the AGE potassium salts to share a common mechanism of toxicity with any other substances, and the AGE potassium salts do not appear to produce a toxic metabolite produced by other substances. For the purposes of these tolerance exemptions, therefore, EPA has assumed that AGE potassium salts do not have a common mechanism of toxicity with other substances. For information regarding EPA’s efforts to determine which chemicals have a common mechanism of toxicity and to evaluate the cumulative effects of such chemicals, see EPA’s website at <https://www.epa.gov/pesticide-science-and-assessing-pesticide-risks/cumulative-assessment-risk-pesticides>.

D. Additional Safety Factor for the Protection of Infants and Children

Section 408(b)(2)(C) of FFDCA provides that EPA shall apply an additional tenfold (10X) margin of safety

for infants and children in the case of threshold effects to account for prenatal and postnatal toxicity and the completeness of the database on toxicity and exposure unless EPA determines based on reliable data that a different margin of safety will be safe for infants and children. This additional margin of safety is commonly referred to as the Food Quality Protection Act safety factor. In applying this provision, EPA either retains the default value of 10X, or uses a different additional safety factor when reliable data available to EPA support the choice of a different factor.

Based on an assessment of surrogate data for the AGE potassium salts, EPA has concluded that there are no toxicological endpoints of concern for the U.S. population, including infants and children. Because there are no threshold effects associated with the AGE potassium salts, EPA conducted a qualitative assessment. As part of that assessment, the Agency did not use safety factors for assessing risk, and no additional safety factor is needed for assessing risk to infants and children.

E. Aggregate Risks and Determination of Safety

Because no toxicological endpoints of concern were identified, EPA concludes that there is a reasonable certainty that no harm will result to the general population, or to infants and children, from aggregate exposure to the AGE potassium salt residues.

V. Analytical Enforcement Methodology

An analytical method is not required for enforcement purposes since the Agency is establishing exemptions from the requirement of a tolerance without any numerical limitation.

VI. Conclusions

Therefore, exemptions from the requirement of a tolerance are established for residues of D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2585031–35–0); D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2587364–77–8); and D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 1228577–37–4) when used as inert ingredients (surfactants) in pesticide formulations applied pre- and post-harvest under 40 CFR 180.910.

VII. Statutory and Executive Order Reviews

This action establishes exemptions from the requirement of a tolerance under FFDCA section 408(d) in response to a petition submitted to the Agency. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled “Regulatory Planning and Review” (58 FR 51735, October 4, 1993). Because this action has been exempted from review under Executive Order 12866, this action is not subject to Executive Order 13211, entitled “Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use” (66 FR 28355, May 22, 2001), or Executive Order 13045, entitled “Protection of Children from Environmental Health Risks and Safety Risks” (62 FR 19885, April 23, 1997). This action does not contain any information collections subject to OMB approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), nor does it require any special considerations under Executive Order 12898, entitled “Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations” (59 FR 7629, February 16, 1994).

Since tolerances and exemptions that are established on the basis of a petition under FFDCA section 408(d), such as the exemptions in this final rule, do not require the issuance of a proposed rule, the requirements of the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*), do not apply.

This action directly regulates growers, food processors, food handlers, and food retailers, not States or tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of FFDCA section 408(n)(4). As such, the Agency has determined that this action will not have a substantial direct effect on States or tribal governments, on the relationship between the National Government and the States or tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled “Federalism” (64 FR 43255, August 10, 1999), and Executive Order 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (65 FR 67249, November 9, 2000), do not apply to this action. In addition, this action does not impose any enforceable duty or

contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1501 *et seq.*).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note).

VIII. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), EPA will submit a report containing this rule 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**. This action is not a “major rule” as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: May 10, 2023.

Charles Smith,

Director, Registration Division, Office of Pesticide Programs.

Therefore, for the reasons stated in the preamble, the EPA amends 40 CFR chapter I as follows:

PART 180—TOLERANCES AND EXEMPTIONS FOR PESTICIDE CHEMICAL RESIDUES IN FOOD

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. In § 180.910, amend Table 1 to 180.910 by adding, in alphabetical order, entries for “D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2587364–77–8)”, “D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 1228577–37–4)”, and “D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2585031–35–0)” to read as follows:

§ 180.910 Inert ingredients used pre- and post-harvest; exemptions from the requirement of a tolerance.

* * * * *

TABLE 1 TO 180.910

Inert ingredients	Limits	Uses
* * * * *		
D-glucopyranose, oligomeric, maleates, C10–16-alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2587364–77–8).		Surfactant.
D-glucopyranose, oligomeric, maleates, C9–11-branched and linear alkyl glycosides, sulfonated, potassium salts (CAS Reg. No. 1228577–37–4).		Surfactant.
D-glucopyranose, oligomeric, maleates, decyl octyl glycosides, sulfonated, potassium salts (CAS Reg. No. 2585031–35–0).		Surfactant.
* * * * *		

[FR Doc. 2023–10349 Filed 5–17–23; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2022–0942; FRL–10868–01–OCSPP]

Erucamide in Pesticide Formulations; Tolerance Exemption

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes an exemption from the requirement of a tolerance for residues of erucamide (CAS Reg. No. 112–84–5) when used as an inert ingredient (lubricant) in pesticide formulations when applied on the raw agricultural commodities honey and honeycomb. Veto-Pharma SAS submitted a petition to EPA under the Federal Food, Drug, and Cosmetic Act (FFDCA), requesting establishment of an exemption from the requirement of a

tolerance. This regulation eliminates the need to establish a maximum permissible level for residues of erucamide, when used in accordance with the terms of this exemption.

DATES: This regulation is effective May 18, 2023. Objections and requests for hearings must be received on or before July 17, 2023 and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2022–0942, is available at <https://www.regulations.gov> or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW, Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room and the OPP docket is (202) 566–1744. For the latest

status information on EPA/DC services, docket access, visit <https://www.epa.gov/dockets>.

FOR FURTHER INFORMATION CONTACT: Charles Smith, Director, Registration Division (7505T), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; main telephone number: (202) 566–2427; email address: RDfrNotices@epa.gov.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).

- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of 40 CFR part 180 through the Office of the Federal Register's e-CFR site at <https://www.ecfr.gov/current/title-40>.

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a(g), any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA-HQ-OPP-2022-0942 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing and must be received by the Hearing Clerk on or before July 17, 2023. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA-HQ-OPP-2022-0942, by one of the following methods:

- **Federal eRulemaking Portal:** <https://www.regulations.gov>. Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.

- **Mail:** OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW, Washington, DC 20460-0001.

- **Hand Delivery:** To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at <https://www.epa.gov/dockets/where-send-comments-epa-dockets#express>.

Additional instructions on commenting or visiting the docket, along with more information about

dockets generally, is available at <https://www.epa.gov/dockets>.

II. Petition for Exemption

In the **Federal Register** of January 3, 2023 (88 FR 38) FRL-9410-08), EPA issued a document pursuant to FFDCA section 408, 21 U.S.C. 346a, announcing the filing of a pesticide petition (PP IN-11624) by Veto-Pharma SAS, 12-14 Rue de la Croix-Martre, 91120 Palaiseau, France. The petition requested that 40 CFR 180.910 be amended by establishing an exemption from the requirement of a tolerance for residues of erucamide (CAS Reg. No. 112-84-5) when used as an inert ingredient (lubricant) in pesticide formulations when applied on the raw agricultural commodities honey and honeycomb. That document referenced a summary of the petition prepared by Veto-Pharma SAS, which is available in the docket, <https://www.regulations.gov>. There were no comments received in response to the notice of filing.

III. Inert Ingredient Definition

Inert ingredients are all ingredients that are not active ingredients as defined in 40 CFR 153.125 and include, but are not limited to, the following types of ingredients (except when they have a pesticidal efficacy of their own): solvents such as alcohols and hydrocarbons; surfactants such as polyoxyethylene polymers and fatty acids; carriers such as clay and diatomaceous earth; thickeners such as carrageenan and modified cellulose; wetting, spreading, and dispersing agents; propellants in aerosol dispensers; microencapsulating agents; and emulsifiers. The term "inert" is not intended to imply nontoxicity; the ingredient may or may not be chemically active. Generally, EPA has exempted inert ingredients from the requirement of a tolerance based on the low toxicity of the individual inert ingredients.

IV. Aggregate Risk Assessment and Determination of Safety

Section 408(c)(2)(A)(i) of FFDCA allows EPA to establish an exemption from the requirement for a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the tolerance is "safe." Section 408(c)(2)(A)(ii) of FFDCA defines "safe" to mean that "there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information." This includes exposure through drinking water and in

residential settings but does not include occupational exposure. When making a safety determination for an exemption from the requirement of a tolerance, FFDCA section 408(c)(2)(B) directs EPA to take into account the considerations set forth in section 408(b)(2)(C) and (D). Section 408(b)(2)(C) of FFDCA requires EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance and to "ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue. . . ." Section 408(b)(2)(D) lists other factors for EPA's consideration in making safety determinations, e.g., the validity, completeness, and reliability of available data, nature of toxic effects, available information concerning the cumulative effects of the pesticide chemical and other substances with a common mechanism of toxicity, and available information concerning aggregate exposure levels to the pesticide chemical and other related substances, among other factors.

EPA establishes exemptions from the requirement of a tolerance only in those cases where it can be clearly demonstrated that the risks from aggregate exposure to pesticide chemical residues under reasonably foreseeable circumstances will pose no harm to human health. In order to determine the risks from aggregate exposure to pesticide inert ingredients, the Agency considers the toxicity of the inert in conjunction with possible exposure to residues of the inert ingredient through food, drinking water, and through other exposures that occur as a result of pesticide use in residential settings. If EPA is able to determine that a finite tolerance is not necessary to ensure that there is a reasonable certainty that no harm will result from aggregate exposure to the inert ingredient, an exemption from the requirement of a tolerance may be established.

Consistent with FFDCA section 408(c)(2)(A), and the factors specified in FFDCA section 408(c)(2)(B), EPA has reviewed the available scientific data and other relevant information in support of this action. EPA has sufficient data to assess the hazards of and to make a determination on aggregate exposure for erucamide, including exposure resulting from the exemption established by this action. EPA's assessment of exposures and risks associated with erucamide follows.

A. Toxicological Profile

EPA has evaluated the available toxicity data and considered their validity, completeness, and reliability as well as the relationship of the results of the studies to human risk. EPA has also considered available information concerning the variability of the sensitivities of major identifiable subgroups of consumers, including infants and children. Specific information on the studies received and the nature of the adverse effects caused by erucamide as well as the no-observed-adverse-effect-level (NOAEL) and the lowest-observed-adverse-effect-level (LOAEL) from the toxicity studies are discussed in this unit.

The available toxicity studies indicate that erucamide has low overall toxicity. Erucamide has low acute toxicity via the oral, dermal, and inhalation routes, is not an eye or skin irritant, and is not a skin sensitizer. No adverse effects were reported in the 90-day oral toxicity study in rats. This study also performed neurobehavioral screening, and no signs of neurotoxicity were reported. No adverse maternal or developmental effects were found in the developmental toxicity study in rats. Also, no effects were observed in the reproduction parameters assessed in the available 90-day study in rats, and predictive toxicology (*i.e.*, computer modeling) indicates that there is no known precedent for reproductive toxic potential for erucamide. Furthermore, concern for carcinogenicity is low, based on negative results in mutagenicity and genotoxicity studies, and the lack of structural alerts for carcinogenicity.

B. Toxicological Points of Departure/Levels of Concern

Once a pesticide's toxicological profile is determined, EPA identifies toxicological points of departure (POD) and levels of concern to use in evaluating the risk posed by human exposure to the pesticide. For hazards that have a threshold below which there is no appreciable risk, the toxicological POD is used as the basis for derivation of reference values for risk assessment. PODs are developed based on a careful analysis of the doses in each toxicological study to determine the dose at which no adverse effects are observed (the NOAEL) and the lowest dose at which adverse effects of concern are identified (the LOAEL). Uncertainty/safety factors are used in conjunction with the POD to calculate a safe exposure level—generally referred to as a population-adjusted dose (PAD) or a reference dose (RfD)—and a safe margin

of exposure (MOE). For non-threshold risks, the Agency assumes that any amount of exposure will lead to some degree of risk. Thus, the Agency estimates risk in terms of the probability of an occurrence of the adverse effect expected in a lifetime. For more information on the general principles EPA uses in risk characterization and a complete description of the risk assessment process, see <https://www.epa.gov/pesticide-science-and-assessing-pesticide-risks/overview-risk-assessment-pesticide-program>.

The hazard profile of erucamide is adequately defined. Overall, erucamide is of low acute, subchronic, and developmental toxicity. No systemic toxicity is observed up to 1,000 mg/kg/day. Since signs of toxicity were not observed, no toxicological endpoints of concern or PODs were identified. Therefore, a qualitative risk assessment for erucamide was performed.

C. Exposure Assessment

1. *Dietary exposure from food and feed uses.* In evaluating dietary exposure to erucamide, EPA considered exposure under the proposed exemption from the requirement of a tolerance and existing uses. EPA assessed dietary exposures from erucamide in food as follows:

Dietary exposure to erucamide may occur from eating foods treated with pesticide formulations containing this inert ingredient and drinking water containing runoff from soils containing the treated crops. Dietary exposure may also occur from non-pesticidal uses (*e.g.*, FDA-approved uses in food contact surfaces). However, a quantitative dietary exposure assessment was not conducted since a toxicological endpoint for risk assessment was not identified.

2. *From non-dietary exposure.* The term “residential exposure” is used in this document to refer to non-occupational, non-dietary exposure (*e.g.*, textiles (clothing and diapers), carpets, swimming pools, and hard surface disinfection on walls, floors, tables).

Erucamide may be present in pesticide and non-pesticide products that may be used in and around the home. However, a quantitative residential exposure assessment was not conducted since a toxicological endpoint for risk assessment was not identified.

3. *Cumulative effects from substances with a common mechanism of toxicity.* Section 408(b)(2)(D)(v) of FFDCA requires that, when considering whether to establish, modify, or revoke a tolerance, the Agency consider

“available information” concerning the cumulative effects of a particular pesticide's residues and “other substances that have a common mechanism of toxicity.”

Based on the lack of toxicity in the available database, EPA has not found erucamide to share a common mechanism of toxicity with any other substances, and erucamide does not appear to produce a toxic metabolite produced by other substances. For the purposes of this tolerance exemption, therefore, EPA has assumed that erucamide does not have a common mechanism of toxicity with other substances. For information regarding EPA's efforts to determine which chemicals have a common mechanism of toxicity and to evaluate the cumulative effects of such chemicals, see EPA's website at <https://www.epa.gov/pesticide-science-and-assessing-pesticide-risks/cumulative-assessment-risk-pesticides>.

D. Additional Safety Factor for the Protection of Infants and Children

Section 408(b)(2)(C) of FFDCA provides that EPA shall apply an additional tenfold (10X) margin of safety for infants and children in the case of threshold effects to account for prenatal and postnatal toxicity and the completeness of the database on toxicity and exposure unless EPA determines based on reliable data that a different margin of safety will be safe for infants and children. This additional margin of safety is commonly referred to as the Food Quality Protection Act safety factor. In applying this provision, EPA either retains the default value of 10X, or uses a different additional safety factor when reliable data available to EPA support the choice of a different factor.

Based on an assessment of erucamide, EPA has concluded that there are no toxicological endpoints of concern for the U.S. population, including infants and children. Because there are no threshold effects associated with erucamide, EPA conducted a qualitative assessment. As part of that assessment, the Agency did not use safety factors for assessing risk, and no additional safety factor is needed for assessing risk to infants and children.

E. Aggregate Risks and Determination of Safety

Because no toxicological endpoints of concern were identified, EPA concludes that there is a reasonable certainty that no harm will result to the general population, or to infants and children, from aggregate exposure to erucamide residues.

V. Other Considerations

Analytical Enforcement Methodology

An analytical method is not required for enforcement purposes since the Agency is establishing an exemption from the requirement of a tolerance without any numerical limitation.

VI. Conclusions

Therefore, an exemption from the requirement of a tolerance is established for residues of erucamide (CAS Reg. No. 112–84–5) when used as an inert ingredient (lubricant) in pesticide formulations when applied on the raw agricultural commodities honey and honeycomb under 40 CFR 180.910.

VII. Statutory and Executive Order Reviews

This action establishes an exemption from the requirement of a tolerance under FFDCA section 408(d) in response to a petition submitted to the Agency. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled “Regulatory Planning and Review” (58 FR 51735, October 4, 1993). Because this action has been exempted from review under Executive Order 12866, this action is not subject to Executive Order 13211, entitled “Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use” (66 FR 28355, May 22, 2001), or Executive Order 13045, entitled “Protection of Children from Environmental Health Risks and Safety Risks” (62 FR 19885, April 23, 1997). This action does not contain any information collections subject to OMB approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), nor does it require any special considerations under Executive Order 12898, entitled

“Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations” (59 FR 7629, February 16, 1994).

Since tolerances and exemptions that are established on the basis of a petition under FFDCA section 408(d), such as the exemption in this final rule, do not require the issuance of a proposed rule, the requirements of the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*), do not apply.

This action directly regulates growers, food processors, food handlers, and food retailers, not States or Tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of FFDCA section 408(n)(4). As such, the Agency has determined that this action will not have a substantial direct effect on States or Tribal governments, on the relationship between the National Government and the States or Tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled “Federalism” (64 FR 43255, August 10, 1999), and Executive Order 13175, entitled “Consultation and Coordination with Indian Tribal Governments” (65 FR 67249, November 9, 2000), do not apply to this action. In addition, this action does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1501 *et seq.*).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section

12(d) of the National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note).

VIII. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), EPA will submit a report containing this rule 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**. This action is not a “major rule” as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: May 10, 2023.

Charles Smith,

Director, Registration Division, Office of Pesticide Programs.

Therefore, for the reasons stated in the preamble, EPA is amending 40 CFR chapter I as follows:

PART 180—TOLERANCES AND EXEMPTIONS FOR PESTICIDE CHEMICAL RESIDUES IN FOOD

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. In § 180.910, amend table 1 to the section by adding, in alphabetical order, the inert ingredient “Erucamide (CAS Reg. No. 112–84–5)” to read as follows:

§ 180.910 Inert ingredients used pre- and post-harvest; exemptions from the requirement of a tolerance.

* * * * *

Inert ingredients	Limits	Uses
* * *	* * *	* * *
Erucamide (CAS Reg. No. 112–84–5)	Lubricant in pesticide formulations	applied on the raw agricultural commodities
	honey and honeycomb.	
* * *	* * *	* * *

DEPARTMENT OF COMMERCE**National Oceanic and Atmospheric Administration****50 CFR Part 217**

[Docket No. 230508–0126]

RIN 0648–BL81

Takes of Marine Mammals Incidental to Specified Activities; Taking Marine Mammals Incidental to U.S. Navy Construction of the Pier 3 Replacement Project at Naval Station Norfolk

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Final rule; notification of issuance of Letter of Authorization.

SUMMARY: NMFS, upon request from the U.S. Navy (Navy), hereby issues regulations to govern the unintentional taking of marine mammals incidental to construction activities associated with the replacement of Pier 3 at Naval Station (NAVSTA) Norfolk in Norfolk, Virginia over the course of 5 years (2023–2028). These regulations, which allow for the issuance of a Letter of Authorization (LOA) for the incidental take of marine mammals during the described activities and specified timeframes, prescribe the permissible methods of taking and other means of effecting the least practicable adverse impact on marine mammal species or stocks and their habitat, as well as requirements pertaining to the monitoring and reporting of such taking.

DATES: This rule is effective from May 18, 2023, through May 18, 2028.

ADDRESSES: A copy of the Navy's application and any supporting documents, as well as a list of the references cited in this document, may be obtained online at: <https://www.fisheries.noaa.gov/action/incidental-take-authorization-us-navy-replacement-pier-3-naval-station-norfolk-norfolk>. In case of problems accessing these documents, please call the contact listed below.

FOR FURTHER INFORMATION CONTACT: Kim Corcoran, Office of Protected Resources, NMFS, ITP.corcoran@noaa.gov, (301) 427–8401.

SUPPLEMENTARY INFORMATION:**Purpose and Need for Regulatory Action**

We received an application from the Navy requesting 5-year regulations and authorization to take multiple species of marine mammals. This rule establishes

a framework under the authority of the Marine Mammal Protection Act (MMPA) (16 U.S.C. 1361 *et seq.*) to allow for the authorization of take by Level A and Level B harassment of marine mammals incidental to the Navy's construction activities related to the replacement of Pier 3 at Naval Station Norfolk in Norfolk, Virginia. Please see Background below for definitions of harassment.

Legal Authority for the Action

Section 101(a)(5)(A) of the MMPA (16 U.S.C. 1371(a)(5)(A)) directs the Secretary of Commerce to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region for up to 5 years if, after notice and public comment, the agency makes certain findings and issues regulations that set forth permissible methods of taking pursuant to that activity and other means of effecting the “least practicable adverse impact” on the affected species or stocks and their habitat (see the discussion below in the Mitigation section), as well as monitoring and reporting requirements. Section 101(a)(5)(A) of the MMPA and the implementing regulations at 50 CFR part 216, subpart I provide the legal basis for issuing this rule containing 5-year regulations, and for any subsequent LOAs. As directed by this legal authority, this rule contains mitigation, monitoring, and reporting requirements.

Summary of Major Provisions Within the Rule

Following is a summary of the major provisions of this rule regarding Navy construction activities. These measures include:

- Required monitoring of the construction areas to detect the presence of marine mammals before beginning construction activities;
- Shutdown of construction activities under certain circumstances to avoid injury of marine mammals; and
- Soft start for impact pile driving to allow marine mammals the opportunity to leave the area prior to beginning impact pile driving at full power.

Background

The MMPA prohibits the “take” of marine mammals, with certain exceptions. Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce (as delegated to NMFS) to allow, upon request, the incidental, but not intentional, taking of small numbers of

marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are proposed or, if the taking is limited to harassment, a notice of a proposed IHA is provided to the public for review.

Authorization for incidental takings shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s) and will not have an unmitigable adverse impact on the availability of the species or stock(s) for taking for subsistence uses (where relevant). Further, NMFS must prescribe the permissible methods of taking and other “means of effecting the least practicable adverse impact” on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stocks for taking for certain subsistence uses (referred to in shorthand as “mitigation”); and requirements pertaining to the mitigation, monitoring and reporting of the takings are set forth. The definitions of all applicable MMPA statutory terms cited above are included in the relevant sections below.

Summary of Request

On April 8, 2022, NMFS received a request from the Navy for authorization to take marine mammals incidental to construction activities related to the replacement of Pier 3 at Naval Station Norfolk in Norfolk, Virginia. Following NMFS' review of the application, the Navy provided responses to questions on June 3, 2022, and August 29, 2022. A revised version of the application was submitted on September 22, 2022. The application was deemed adequate and complete on September 26, 2022, and published in the **Federal Register** for public review and comment on October 7, 2022 (87 FR 60998). We did not receive substantive comments on the notice of receipt (NOR).

On March 9, 2023, NMFS published a notice of proposed rulemaking in the **Federal Register** (88 FR 14560). The regulations are valid for 5 years (2023–2028) from the date of issuance, and authorize the Navy to take five species of marine mammals by Level B harassment and, for a subset of these species, Level A harassment incidental to construction activities related to the replacement of Pier 3 at Naval Station Norfolk, Norfolk, Virginia. Neither the Navy nor NMFS expect serious injury or mortality to marine mammals to result from this activity, and none has been authorized.

NMFS previously issued an Incidental Harassment Authorization (IHA) (87 FR 15945, March 21, 2022) to the Navy for authorization to take marine mammals during the first year of the construction project described in this rule. Upon request from the Navy, NMFS modified the 2022 IHA (88 FR 2880, January 18, 2023) to include concurrent pile driving and drilling activities due to a change in the contractor's construction plan that was not initially analyzed in the initial activity. This rule could not be completed prior to expiration of the Navy's modified 2022 IHA and, therefore, the Navy requested issuance of a renewal IHA associated with continued work towards completion of year 1 of the construction project. The requested renewal IHA was issued on March 30, 2023 (88 FR 20133, April 5, 2023). As required, the Navy provided monitoring reports (available at: <https://www.fisheries.noaa.gov/action/incidental-take-authorization-replacement-pier-3-naval-station-norfolk-norfolk-virginia>) that confirm that it has implemented the required mitigation and monitoring, and also show that no impacts of a scale or nature not previously analyzed or authorized have occurred as a result of the activities conducted. No changes were made from the proposed to the final rule.

Description of the Activity

Overview

The Navy is currently conducting, and will continue, the replacement of Pier 3 at NAVSTA Norfolk, in Norfolk, VA. The aforementioned 2022 IHA (as modified) and subsequent renewal covered the first year of project activities, and this rule covers the remaining activities for the pier replacement. During this period demolition and construction activities will occur at existing Pier 3, new Pier 3, CEP-176 wharf, CEP-102 relieving platform, and on a fender system of CEP-175 bulkhead (See Figure 1). Activities under the rule include both vibratory pile driving and removal, impact pile driving, and pre-drilling (hereafter, referred to as "drilling"). Sounds resulting from pile driving, drilling, and removal may result in the incidental take of marine mammals by Level A and Level B harassment in the form of auditory injury or behavioral harassment.

Dates and Duration

The regulations are valid for a period of 5 years (2023–2028). The specified activities may occur at any time during the 5-year period of validity of the regulations. The Navy expects pile driving and drilling for the entire

project to occur on approximately 513 non-consecutive days over a 4-year duration, with the greatest amount of work occurring during Year 4 (approximately 204 days). However, in the event of unforeseen delays, the project may occur over the full 5-year duration of this rule. The Navy plans to conduct all work during daylight hours.

Specific Geographic Region

Pier 3 at NAVSTA Norfolk is located at the confluence of the Elizabeth River, James River, Nansemond River, LaFayette River, Willoughby Bay, and Chesapeake Bay (Figure 2).

Anthropogenic sound is a significant contributor to the ambient acoustic environment surrounding NAVSTA Norfolk, as it is located in close proximity to shipping channels as well as several Port of Virginia facilities with frequent vessel traffic that altogether have an annual average of 1,788 vessel calls (Port of Virginia, 2021). Other sources of human-generated underwater sound not specific to naval installations include sounds from echosounders on commercial and recreational vessels, industrial ship noise, and noise from recreational boat engines. Additionally, on average, maintenance dredging of the navigation channel occurs every 2 years (USACE and Port of Virginia, 2018).

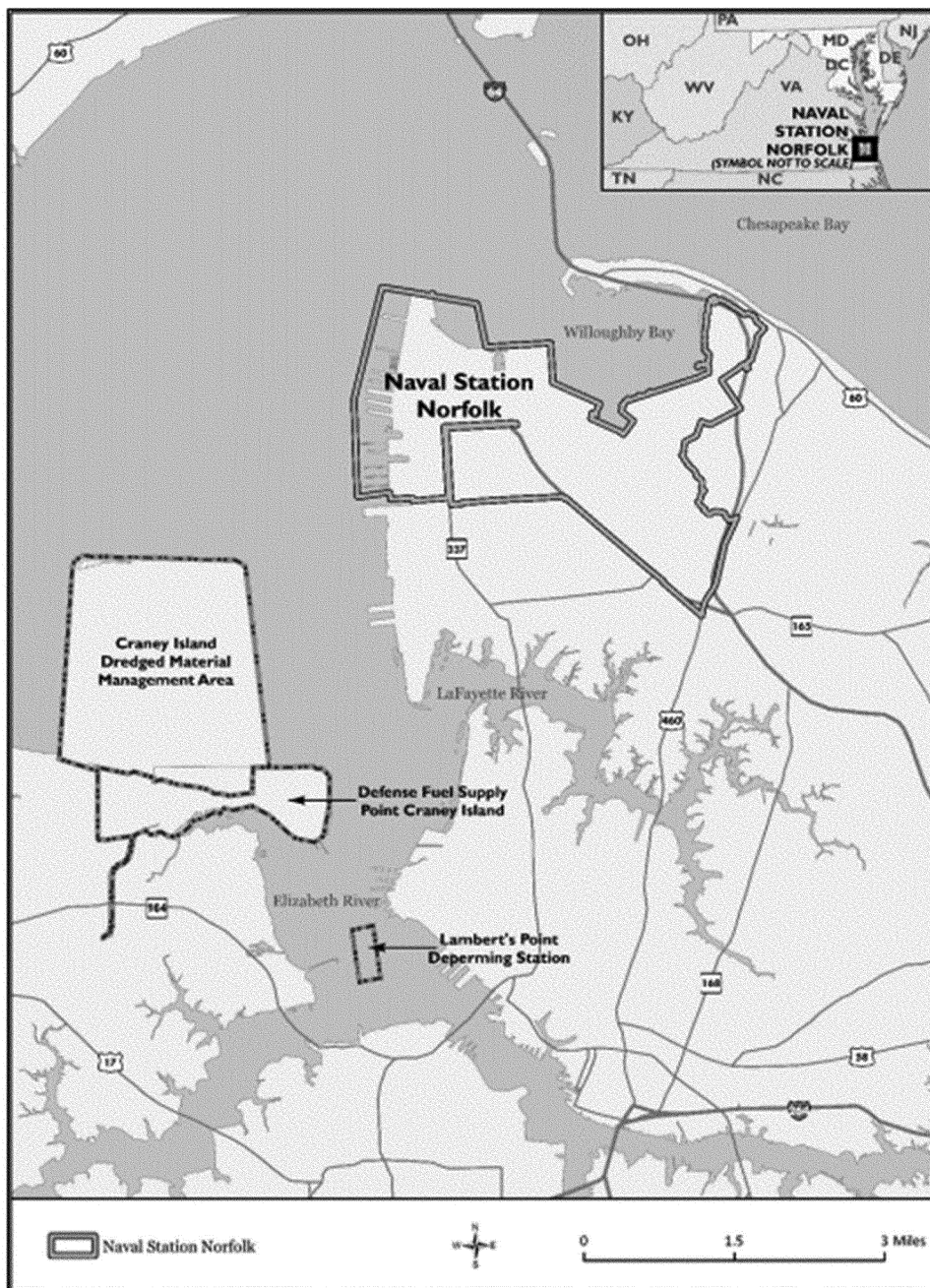


Figure 1 -- Site Location Map for NAVSTA Norfolk in Norfolk, Virginia

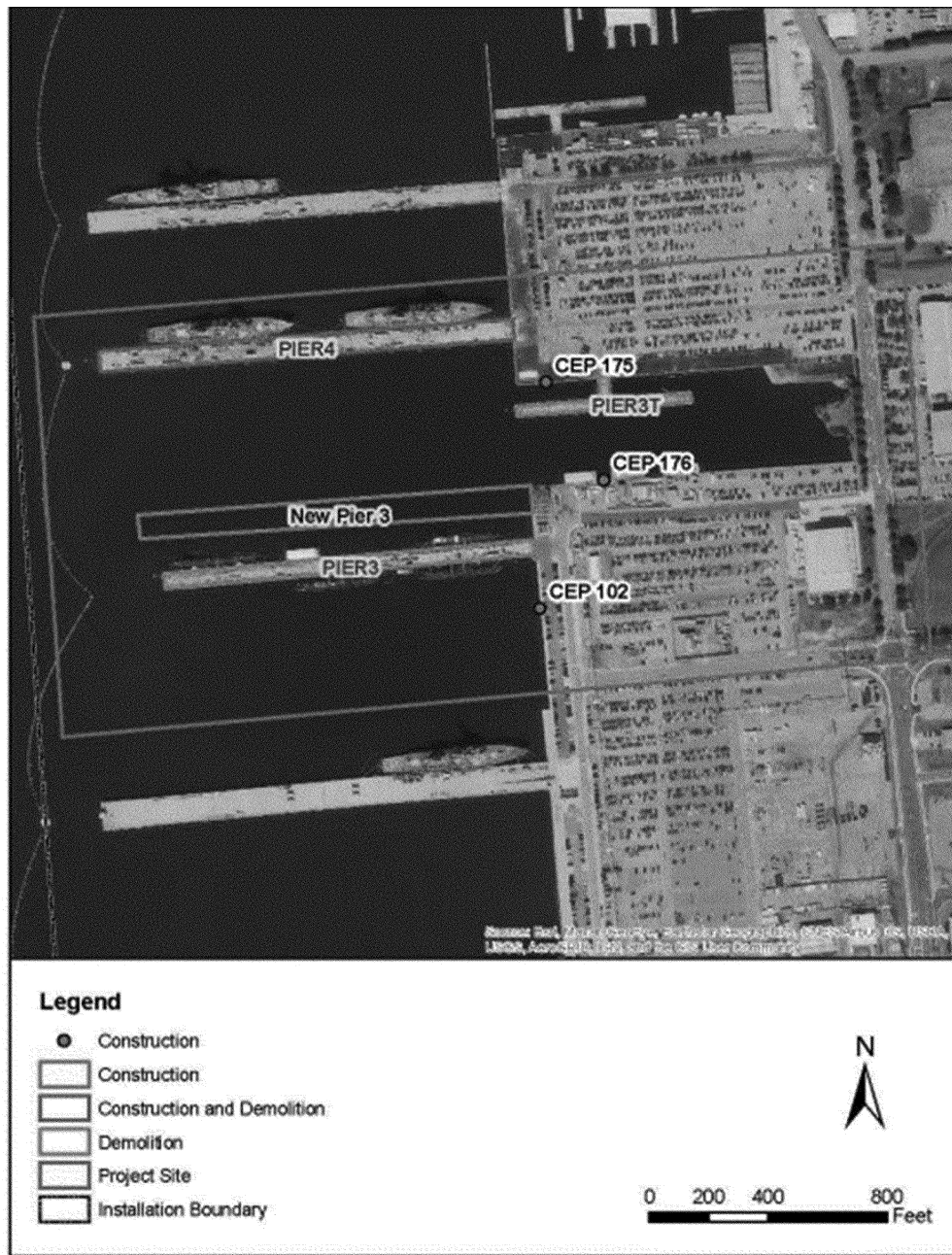


Figure 2 -- Project Site Map at NAVSTA Norfolk in Norfolk, Virginia

Detailed Description of Specific Activity

The project involves the replacement of Pier 3 at NAVSTA waterfront. The existing Pier 3 will be completely demolished and a new Pier 3 will be constructed immediately north of the existing location (Figure 2). The project scope for the replacement of Pier 3 under this rule will also include construction of new CEP-176 wharf, construction of new CEP-102 relieving platform, and construction of a portion of fender system at CEP-175. The project includes six phases, the first of which has begun under the previously

issued IHA (87 FR 15945, March 21, 2022). A preliminary work schedule and activity details for the work under this rule are provided in Table 1. In-water construction activities, including pile driving, pile removal, and drilling are described in detail below:

Pile Removal—Piles are anticipated to be removed with a vibratory hammer, however, direct pull or clamshell removal may be used depending on site conditions. All three pile removal methods are described below. Take is not expected to occur for clamshell and direct pull removal, therefore they will

not be described past what is provided below nor included in our analysis:

- **Vibratory Extraction**—This method uses a barge-mounted crane with a vibratory driver to remove all pile types. The vibratory driver is a large mechanical device (5 to 16 tons (4.5 to 14.5 metric tons)) suspended from a crane by a cable and positioned on top of a pile. The pile is then loosened from the sediments by activating the driver and slowly lifting up on the driver with the aid of the crane. Once the pile is released from the sediments, the crane continues to raise the driver and pull

the pile from the sediment. The driver is typically shut off once the pile is loosened from the sediments. The pile is then pulled from the water and placed on a barge. Vibratory extraction usually takes between less than 1 minute (for timber piles) to 30 minutes per pile depending on the pile size, type, and substrate conditions;

- **Clamshell**—In cases where use of a vibratory driver is not possible (e.g., when the pile may break apart from clamp force and vibration), a clamshell apparatus may be lowered from the crane in order to remove pile stubs. The use and size of the clamshell bucket would be minimized to reduce the potential for generating turbidity during removal; and

- **Direct Pull**—Piles may be removed by wrapping the piles with a cable or chain and pulling them directly from

the sediment with a crane. In some cases, depending on access and location, piles may be cut at or below the mudline.

Pile Installation—Pile installation/removal would occur using land-based or barge-mounted cranes, as appropriate. Concrete piles would be installed using an impact hammer. Steel piles and polymeric piles can be installed using an impact hammer or vibratory hammer. Hammers can be steam, air, or diesel drop, single-acting, double-acting, differential-acting, or hydraulic type. Additionally, pre-drilling may occur for installation of concrete piles and at locations where there may be a higher likelihood of obstructions or where soil layers are harder to penetrate. Drilling is not permitted for installation of steel piles

on this project or for concrete piles at Pier 3 because hard soil layers are not expected at these locations.

Table 1 provides the estimated construction schedule and production rates for the construction activities considered for this rulemaking beginning with Year 2. As indicated above, Year 1 of the Pier 3 replacement project was authorized under the 2022 IHA and subsequent renewal. Therefore, Year 2 of the project aligns with year 1 of the rule. Some project elements will use only one method of pile installation (e.g., impact hammer or vibratory hammer or impact hammer and drilling), but all methods have been analyzed. The method of installation will be determined by the construction crew once demolition and installation has begun.

TABLE 1—PRELIMINARY CONSTRUCTION SCHEDULE FOR IN-WATER ACTIVITIES

Year***	Activity	Total number of piles	Activity component	Method	Daily rate (piles/day)	Total days	Total days per year
Year 2	CEP-176 Bulkhead	103	42-inch Steel Pipe Bearing Piles.	Install: Impact or Vibratory	4	26	185
Year 2	CEP-176 Bulkhead	221	28-inch sheet piles	Install: Impact or Vibratory	14	16	
Year 2	CEP-176 Bulkhead	9	13-inch polymeric fender piles	Install: Impact or Vibratory *	5	2	
Year 2	CEP-102 Platform phase 2	11	24-inch square precast concrete bearing piles.	Install: Impact *	2	6	
Year 2	Pier 3	280	24-inch square precast concrete.	Install: Impact	4	70	
Year 2	CEP-102 Platform phase 2	6	18-inch square precast concrete fender piles.	Install: Impact	4	2	
Year 2	Pier 3	250	24-inch square precast concrete bearing piles.	Install: Impact	4	63	
Year 3	Pier 3	409	24-inch square precast concrete fender files.	Install: Impact *	6	69	92
Year 3	Pier 3	18	18-inch steel pipe fender piles	Install: Impact	6	3	
Year 3	CEP-102 Platform South Portion.	26	42-inch steel pipe bearing piles	Install: Impact or Vibratory	2	13	
Year 3	CEP-102 Platform South Portion.	53	28-inch steel sheet piles	Install: Impact or Vibratory	14	4	
Year 3	CEP-102 Platform South Portion.	26	18-inch square precast concrete fender piles**.	Extract: Vibratory	9	3	
Year 4	CEP-102 Platform South Portion.	40	24-inch square precast concrete bearing piles.	Install: Impact *	2	20	204
Year 4	Existing Pier 3	624	14-inch timber fender piles** ...	Extract: Vibratory	25	25	
Year 4	CEP-102 Platform South Portion.	25	18-inch square precast concrete fender piles.	Install: Impact *	4	7	
Year 4	CEP-102 Platform Center Portion.	50	42-inch steel pipe bearing piles	Install: Impact or Vibratory	2	25	
Year 4	Existing Pier 3	72	24-inch square precast concrete fender piles**.	Extract: Vibratory	12	6	
Year 4	CEP-102 Platform Center Portion.	102	28-inch steel sheet piles	Install: Impact or Vibratory	14	8	
Year 4	CEP-102 Platform Center Portion.	36	18-inch square precast concrete fender piles**.	Extract: Vibratory	9	4	
Year 4	Existing Pier 3	873	16-inch and 18-inch square precast concrete bearing piles**.	Extract: Vibratory	10	88	
Year 4	CEP-102 Platform Center Portion.	41	24-inch square precast concrete bearing piles.	Install: Impact *	2	21	
Year 5	Existing Pier 3	30	16- and 18-inch square precast bearing piles**.	Extract: Vibratory	10	3	32
Year 5	CEP-102 Platform Center Portion.	32	24-inch square precast bearing piles.	Install: Impact *	2	16	
Year 5	CEP-102 Platform Center Portion.	50	18-inch square precast concrete fender piles.	Install: Impact *	4	13	
Total Piles Installed		1,726				513	
Total Piles Removed		1,661					

Note: Estimated construction schedule. Delays may occur due to equipment failure or weather.

* Pre-drilling is permitted to assist with pile installation.

** Denotes piles removed.

*** Year 2 refers to the second year of the Pier 3 replacement project, however it is considered as Year 1 under this 2023 rule.

Concurrent Activities—In order to maintain project schedules, it is likely that multiple pieces of equipment would operate at the same time within the project area. Table 2 provides a summary of the possible equipment

combinations by structure and construction year where a maximum of four in-water activities may be occurring simultaneously. As mentioned above, the method of installation, and whether concurrent pile driving scenarios will be

implemented, will be determined by the construction crew once the project has begun. Therefore, the total take estimate reflects the worst case scenario for the project.

TABLE 2—SUMMARY OF POSSIBLE CONCURRENT PILE DRIVING SCENARIOS

Year	Structure	Pile types	Total equipment quantity	Equipment (quantity)
Year 3	Pier 3	Driving of precast bearing piles	2	Rotary Drill (2).
			2	Impact Hammer (1), Rotary Drill (1)
			2	Impact Hammer (2).
	CEP-102	Driving 42-inch steel pipe and 28-inch steel sheet	2	Vibratory Hammer (2).
Year 4			2	Impact Hammer (2).
			2	Vibratory Hammer (1), Impact Hammer (1).
	Existing Pier 3 and CEP-102.	Extraction of 14-inch timber piles from Pier 3 and Driving of 42-inch steel pipe, sheet piles, and precast concrete piles.	4	Vibratory Hammer (3), Rotary Drill (1).
			4	Vibratory Hammer (2), Impact Hammer (2), Rotary Drill (1).
Year 4–Year 5 ...	Existing Pier 3 and CEP-102.	Extraction of 16- to 18-inch concrete piles from Pier 3 and Driving of 24-inch precast concrete bearing piles.	4	Vibratory (1), Impact Hammer (3).
			2	Vibratory Hammer (1), Rotary Drill (1).
			2	Vibratory Hammer (1), Impact Hammer (1).

Mitigation, monitoring, and reporting measures are described in detail later in this document (please see Mitigation and Monitoring and Reporting).

Comments and Responses

NMFS' notice of proposed rulemaking was published in the **Federal Register** on March 9, 2023 (88 FR 14560). That proposed rule described, in detail, the Navy's activities, the marine mammal species that may be affected by the activities, and the anticipated effects on marine mammals. In that proposed rule, we requested public input on the request for authorization described therein, our analyses, the proposed authorization, and any other aspect of the notice of proposed rulemaking, and requested that interested persons submit relevant information, suggestions, and comments. The proposed rule was available for a 30-day public comment period.

During the 30-day public comment period, NMFS received one substantive comment submission, from a member of the public. NMFS' responses to the comments in the submission are provided below, and all comments are available online at: <https://www.regulations.gov/document/NOAA-NMFS-2022-0110-0001/comment>.

Comment 1: A member of the public noted that the Navy's construction work has the potential to cause sediment runoff into the marine environment, which can smother marine plants and reduce light availability for primary productivity. The individual indicated agreement with the mitigation measures

as outlined in the notice of proposed rulemaking and recommends that extra vegetation be planted and heavy monitoring of substrates occur throughout the project. The individual also noted concerns with the impact of underwater noise on the life history of marine fish species as well as sea turtles.

Response: NMFS appreciates the commenter's engagement in the rulemaking process, but notes that concerns regarding sediment runoff are outside NMFS' purview under the MMPA, except inasmuch as such impacts may affect marine mammal habitat (including prey). Similarly, concerns related to species other than marine mammals (and marine mammal habitat), such as sea turtles, are outside NMFS' purview under the MMPA. As required under the MMPA, NMFS assessed the impacts of the Navy's construction project on marine mammals and their habitat and made the necessary findings in support of issuance of this rule and subsequent LOA. NMFS notes that mitigation and monitoring prescribed will affect the least practicable adverse impact on marine mammals and their habitat.

As described in the proposed rule (88 FR 14560, March 9, 2023), NMFS finds that the most likely impact to fish (*i.e.*, potential prey) from pile driving activities at the project areas would be temporary behavioral avoidance of the area. The duration of fish avoidance of this area after pile driving stops is unknown, but a rapid return to normal recruitment, distribution and behavior

is anticipated. Any behavioral avoidance by fish of the disturbed area would still leave significantly large areas of fish and marine mammal foraging habitat in the nearby vicinity.

Construction activities, in the form of increased turbidity, have the potential to adversely affect forage fish in the project area. Forage fish form a significant prey base for many marine mammal species that occur in the project area. Increased turbidity is expected to occur in the immediate vicinity of construction activities. However, suspended sediments and particulates are expected to dissipate quickly within a single tidal cycle. Given the limited area affected, any effects on forage fish are expected to be minor or negligible.

Comment 2: The commenter indicated concern regarding the length of time for which the rule is valid, noting five years is a significant amount of time and believes the regulations should be valid for a shorter period of time so NMFS is able to reevaluate the success of the mitigation and monitoring plan.

Response: MMPA section 101(a)(5)(A) allows the authorization of incidental taking of marine mammals by U.S. citizens incidental to specified activities for up to 5 consecutive years, as requested by the Navy in this case. Therefore, NMFS has determined that 5 years is an appropriate length of time for effectiveness of the rule. Additionally, the regulations governing the take of marine mammals incidental to Navy construction activities contains an adaptive management component.

Please see the Adaptive Management section for more detail.

Comment 3: The individual recommends that trained professionals report on any harm to marine life, the use of visual and acoustic monitoring techniques, and measures to limit noise pollution in the marine environment.

Response: NMFS concurs with the recommendation to use trained professional protected species observers (PSOs), which were included in the proposed rule as well as this final rule. These PSOs will provide adequate visual monitoring to ensure the Navy complies with the requirements outlined in their issued LOA. The Navy will also collect acoustic data for specified piles as outlined in their Marine Mammal Monitoring Plan. Additionally, the Navy will submit a visual and acoustic monitoring report to NMFS annually, well as a comprehensive report at the conclusion of the five years. Please see the Mitigation and Monitoring and Reporting sections of this final rule for additional details.

Description of Marine Mammals in the Area of Specified Activities

Sections 3 and 4 of the application summarize available information

regarding status and trends, distribution and habitat preferences, and behavior and life history of the potentially affected species. NMFS fully considered all of this information, and we refer the reader to these descriptions, incorporated here by reference, instead of reprinting the information.

Additional information regarding population trends and threats may be found in NMFS' Stock Assessment Reports (SARs; www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments) and more general information about these species (e.g., physical and behavioral descriptions) may be found on NMFS' website (<https://www.fisheries.noaa.gov/find-species>).

Table 3 lists all species or stocks for which take is expected and is authorized for this activity, and summarizes information related to the population or stock, including regulatory status under the MMPA and Endangered Species Act (ESA) and potential biological removal (PBR), where known. PBR is defined by the MMPA as the maximum number of animals, not including natural mortalities, that may be removed from a marine mammal stock while allowing

that stock to reach or maintain its optimum sustainable population (as described in NMFS' SARs). While no serious injury or mortality is expected to occur, PBR and annual serious injury and mortality from anthropogenic sources are included here as gross indicators of the status of the species or stocks and other threats.

Marine mammal abundance estimates presented in this document represent the total number of individuals that make up a given stock or the total number estimated within a particular study or survey area. NMFS' stock abundance estimates for most species represent the total estimate of individuals within the geographic area, if known, that comprises that stock. For some species, this geographic area may extend beyond U.S. waters. All stocks managed under the MMPA in this region are assessed in NMFS' U.S. Atlantic and Gulf of Mexico SARs. All values presented in Table 2 are the most recent available at the time of publication, including from the draft 2022 SARs, and are available online at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments.

TABLE 3—SPECIES LIKELY IMPACTED BY THE SPECIFIED ACTIVITIES

Common name	Scientific name	Stock	ESA/ MMPA status; strategic (Y/N) ¹	Stock abundance (CV, N _{min} , most recent abundance survey) ²	PBR	Annual M/SI ³
Order Cetartiodactyla—Cetacea—Superfamily Mysticeti (baleen whales)						
Family Balaenopteridae (rorquals): Humpback whale	<i>Megaptera novaeangliae</i>	Gulf of Maine	-, -, Y	1,396 (0, 1,380, 2016)	22	12.15
Superfamily Odontoceti (toothed whales, dolphins, and porpoises)						
Family Delphinidae: Bottlenose dolphin	<i>Tursiops truncatus</i>	Western North Atlantic (WNA) Coastal, Northern Migratory. WNA Coastal, Southern Mi- gratory. Northern North Carolina Estu- arine.	-, -, Y -, -, Y -, -, Y	6,639 (0.41, 4,759, 2016) 3,751 (0.6, 2,353, 2016) 823 (0.06, 782, 2017)	48 24 7.8	12.2–21.5 0–18.3 7.2–30
Family Phocoenidae (por- poises): Harbor porpoise	<i>Phocoena phocoena</i>	Gulf of Maine/Bay of Fundy ...	-, -, N	95,543 (0.31, 74,034, 2016) ..	851	164
Order Carnivora—Superfamily Pinnipedia						
Family Phocidae (earless seals): Harbor seal	<i>Phoca vitulina</i>	Western North Atlantic	-, -, N	61,336 (0.08, 57,637, 2018) ..	1729	339
Gray seal	<i>Halichoerus grypus</i>	Western North Atlantic	-, -, N	27,300 (0.22, 22,785, 2016) ..	1458	4453

¹ Endangered Species Act (ESA) status: Endangered (E), Threatened (T)/MMPA status: Depleted (D). A dash (-) indicates that the species is not listed under the ESA or designated as depleted under the MMPA. Under the MMPA, a strategic stock is one for which the level of direct human-caused mortality exceeds PBR or which is determined to be declining and likely to be listed under the ESA within the foreseeable future. Any species or stock listed under the ESA is automatically designated under the MMPA as depleted and as a strategic stock.

² NMFS marine mammal stock assessment reports online at: <https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessment-reports>. CV is coefficient of variation; N_{min} is the minimum estimate of stock abundance.

³ These values, found in NMFS's SARs, represent annual levels of human-caused mortality plus serious injury from all sources combined (e.g., commercial fisheries, ship strike). Annual M/SI often cannot be determined precisely and is in some cases presented as a minimum value or range. A CV associated with estimated mortality due to commercial fisheries is presented in some cases.

⁴ This stock abundance estimate is only for the U.S. portion of this stock. The actual stock abundance, including the Canadian portion of the population, is estimated to be approximately 424,300 animals. The PBR value listed here is only for the U.S. portion of the stock, while M/SI reflects both the Canadian and U.S. portions.

As indicated above, all five species (with seven managed stocks) in Table 3 temporally and spatially co-occur with the activity to the degree that take is reasonably likely to occur. While North Atlantic right whales (*Eubalaena glacialis*), minke whales (*Balaenoptera acutorostrata acutorostata*), and fin whales (*Balaenoptera physalus*) have been documented in the area, the temporal and/or spatial occurrence of these whales is far outside the area for this project and take is not expected to occur. Therefore, they are not discussed further beyond the explanation provided in the **Federal Register** proposed rule (88 FR 14560, March 9, 2023).

A detailed description of the species likely to be affected by the Navy's project, including brief introductions to the species and relevant stocks as well as available information regarding population trends and threats, and information regarding local occurrence, were provided in the **Federal Register** proposed rule (88 FR 14560, March 9, 2023). Since that time, we are not aware of any changes in the status of these species and stocks; therefore, detailed descriptions are not provided here. Please refer to that **Federal Register** proposed rule for these descriptions. Please also refer to the NMFS website (<https://www.fisheries.noaa.gov/find-species>) for generalized species accounts.

Unusual Mortality Events

An unusual mortality event (UME) is defined under Section 410(6) of the

MMPA as a stranding that is unexpected; involves a significant die-off of any marine mammal population; and demands immediate response. Currently, there are active UMEs for northeast pinnipeds (harbor and gray seals) and humpback whales along the East Coast.

Northeast Pinniped UME

Since June 2022, elevated numbers of sick and dead harbor seal and gray seal have been documented along the southern and central coast of Maine from Biddeford to Boothbay (including Cumberland, Lincoln, Knox, Sagadahoc, and York Counties). This event has been declared a UME. Additional information is available at: <https://www.fisheries.noaa.gov/2022-pinniped-unusual-mortality-event-along-maine-coast>.

Atlantic Humpback Whale UME

Since January 2016, elevated humpback whale mortalities have occurred along the Atlantic coast from Maine through Florida. This event was declared an UME in 2017 however. As of April 2023, six humpback whales have been found stranded in Virginia. A portion of the whales have shown evidence of pre-mortem vessel strike; however, this finding is not consistent across all whales examined, and additional research is needed. Additional information is available at <https://www.fisheries.noaa.gov/national/marine-life-distress/2016-2021-humpback-whale-unusual-mortality-event-along-atlantic-coast>.

Marine Mammal Hearing

Hearing is the most important sensory modality for marine mammals underwater, and exposure to anthropogenic sound can have deleterious effects. To appropriately assess the potential effects of exposure to sound, it is necessary to understand the frequency ranges marine mammals are able to hear. Not all marine mammal species have equal hearing capabilities (e.g., Richardson *et al.*, 1995; Wartzok and Ketten, 1999; Au and Hastings, 2008). To reflect this, Southall *et al.* (2007, 2019) recommended that marine mammals be divided into hearing groups based on directly measured (behavioral or auditory evoked potential techniques) or estimated hearing ranges (behavioral response data, anatomical modeling, *etc.*). Note that no direct measurements of hearing ability have been successfully completed for mysticetes (*i.e.*, low-frequency cetaceans). Subsequently, NMFS (2018) described generalized hearing ranges for these marine mammal hearing groups. Generalized hearing ranges were chosen based on the approximately 65 decibel (dB) threshold from the normalized composite audiograms, with the exception for lower limits for low-frequency cetaceans where the lower bound was deemed to be biologically implausible and the lower bound from Southall *et al.* (2007) retained. Marine mammal hearing groups and their associated hearing ranges are provided in Table 4.

TABLE 4—MARINE MAMMAL HEARING GROUPS
[NMFS, 2018]

Hearing group	Generalized hearing range*
Low-frequency (LF) cetaceans (baleen whales)	7 Hz to 35 kHz.
Mid-frequency (MF) cetaceans (dolphins, toothed whales, beaked whales, bottlenose whales)	150 Hz to 160 kHz.
High-frequency (HF) cetaceans (true porpoises, <i>Kogia</i> , river dolphins, Cephalorhynchid, <i>Lagenorhynchus cruciger</i> & <i>L. australis</i>).	275 Hz to 160 kHz.
Phocid pinnipeds (PW) (underwater) (true seals)	50 Hz to 86 kHz.
Otariid pinnipeds (OW) (underwater) (sea lions and fur seals)	60 Hz to 39 kHz.

* Represents the generalized hearing range for the entire group as a composite (*i.e.*, all species within the group), where individual species' hearing ranges are typically not as broad. Generalized hearing range chosen based on ~65 dB threshold from normalized composite audiogram, with the exception for lower limits for LF cetaceans (Southall *et al.* 2007) and PW pinniped (approximation).

The pinniped functional hearing group was modified from Southall *et al.* (2007) on the basis of data indicating that phocid species have consistently demonstrated an extended frequency range of hearing compared to otariids, especially in the higher frequency range (Hemilä *et al.*, 2006; Kastelein *et al.*, 2009; Reichmuth and Holt, 2013).

For more detail concerning these groups and associated frequency ranges,

please see NMFS (2018) for a review of available information.

Potential Effects of Specified Activities on Marine Mammals and Their Habitat

The effects of underwater noise from the Navy's construction activities have the potential to result in Level A and Level B harassment of marine mammals in the vicinity of the project area. The notice of the proposed rulemaking (88

FR 14560, March 9, 2023) included a discussion of the effects of anthropogenic noise on marine mammals and the potential effects of underwater noise from the Navy's construction activities on marine mammals and their habitat. That information and analysis is referenced in this final rule and is not repeated here; please refer to the notice of

proposed rulemaking (88 FR 14560; March 9, 2023).

Estimated Take

This section provides an estimate of the number of incidental takes that may be authorized under this rule, which will inform both NMFS' consideration of "small numbers," and the negligible impact determinations.

Harassment is the only type of take expected to result from these activities. Except with respect to certain activities not pertinent here, section 3(18) of the MMPA defines "harassment" as any act of pursuit, torment, or annoyance, which (i) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment); or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment).

Authorized takes will primarily be by Level B harassment, as noise generated from in-water pile driving (vibratory and impact) and drilling has the potential to result in disruption of behavioral patterns for individual marine mammals. There is also some potential for auditory injury (Level A harassment) to result, primarily for high- and low-frequency species and phocids because predicted auditory injury zones are larger than for mid-frequency species. However, auditory injury is unlikely to occur for low- and mid-frequency species as shutdown zones encompass the entirety of the auditory injury zones for all activities (see Mitigation section). The mitigation and monitoring measures are expected to minimize the severity of the taking to the extent practicable.

As described previously, no serious injury or mortality is anticipated or is authorized for this activity. Below we describe how the take numbers are estimated.

For acoustic impacts, generally speaking, we estimate take by considering: (1) acoustic thresholds above which NMFS believes the best available science indicates marine mammals will be behaviorally harassed or incur some degree of permanent hearing impairment; (2) the area or volume of water that will be ensonified above these levels in a day; (3) the density or occurrence of marine mammals within these ensonified areas; and (4) the number of days of activities. We note that while these factors can contribute to a basic calculation to provide an initial prediction of potential takes, additional information that can qualitatively inform take estimates is also sometimes available (e.g., previous monitoring results or average group size). Below, we describe the factors considered here in more detail and present the take estimates.

Acoustic Thresholds

NMFS recommends the use of acoustic thresholds that identify the received level of underwater sound above which exposed marine mammals would be reasonably expected to be behaviorally harassed (equated to Level B harassment) or to incur PTS of some degree (equated to Level A harassment).

Level B Harassment—Though significantly driven by received level, the onset of behavioral disturbance from anthropogenic noise exposure is also informed to varying degrees by other factors related to the source or exposure context (e.g., frequency, predictability, duty cycle, duration of the exposure, signal-to-noise ratio, distance to the source), the environment (e.g., bathymetry, other noises in the area, predators in the area), and the receiving animals (hearing, motivation, experience, demography, life stage, depth) and can be difficult to predict (e.g., Southall *et al.*, 2007, 2021; Ellison *et al.*, 2012). Based on what the available science indicates and the practical need to use a threshold based

on a metric that is both predictable and measurable for most activities, NMFS typically uses a generalized acoustic threshold based on received level to estimate the onset of behavioral harassment. NMFS generally predicts that marine mammals are likely to be behaviorally harassed in a manner considered to be Level B harassment when exposed to underwater anthropogenic noise above root-mean-squared pressure received levels (RMS SPL) of 120 dB (referenced to 1 micropascal (re 1 μ Pa)) for continuous (e.g., vibratory pile-driving, drilling) and above RMS SPL 160 dB re 1 μ Pa for non-explosive impulsive (e.g., impact pile driving) or intermittent (e.g., scientific sonar) sources.

The Navy's construction includes the use of continuous (vibratory pile driving/removal, drilling) and impulsive (impact pile driving) sources, and therefore the 120 and 160 dB re 1 μ Pa (rms) are applicable.

Level A Harassment—NMFS' Technical Guidance for Assessing the Effects of Anthropogenic Sound on Marine Mammal Hearing (Version 2.0) (Technical Guidance, 2018) identifies dual criteria to assess auditory injury (Level A harassment) to five different marine mammal groups (based on hearing sensitivity) as a result of exposure to noise from two different types of sources (impulsive or non-impulsive). As previously noted, the Navy's activity includes the use of non-impulsive (vibratory pile driving/removal, drilling) and impulsive (impact pile driving) sources.

These thresholds are provided in the table below. The references, analysis, and methodology used in the development of the thresholds are described in NMFS' 2018 Technical Guidance, which may be accessed at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-acoustic-technical-guidance.

TABLE 5—THRESHOLDS IDENTIFYING THE ONSET OF PERMANENT THRESHOLD SHIFT

Hearing group	PTS onset acoustic thresholds* (received level)	
	Impulsive	Non-impulsive
Low-Frequency (LF) Cetaceans	Cell 1: $L_{pk,flat}$: 219 dB; $L_{E,LF,24h}$: 183 dB	Cell 2: $L_{E,LF,24h}$: 199 dB.
Mid-Frequency (MF) Cetaceans	Cell 3: $L_{pk,flat}$: 230 dB; $L_{E,MF,24h}$: 185 dB	Cell 4: $L_{E,MF,24h}$: 198 dB.
High-Frequency (HF) Cetaceans	Cell 5: $L_{pk,flat}$: 202 dB; $L_{E,HF,24h}$: 155 dB	Cell 6: $L_{E,HF,24h}$: 173 dB.
Phocid Pinnipeds (PW) (Underwater)	Cell 7: $L_{pk,flat}$: 218 dB; $L_{E,PW,24h}$: 185 dB	Cell 8: $L_{E,PW,24h}$: 201 dB.
Otariid Pinnipeds (OW) (Underwater)	Cell 9: $L_{pk,flat}$: 232 dB; $L_{E,OW,24h}$: 203 dB	Cell 10: $L_{E,OW,24h}$: 219 dB.

* Dual metric acoustic thresholds for impulsive sounds: Use whichever results in the largest isopleth for calculating PTS onset. If a non-impulsive sound has the potential of exceeding the peak sound pressure level thresholds associated with impulsive sounds, these thresholds should also be considered.

Note: Peak sound pressure (L_{pk}) has a reference value of 1 μ Pa, and cumulative sound exposure level (L_E) has a reference value of 1 μ Pa²s. In this Table, thresholds are abbreviated to reflect American National Standards Institute standards (ANSI, 2013). However, peak sound pressure is defined by ANSI as incorporating frequency weighting, which is not the intent for this Technical Guidance. Hence, the subscript “flat” is being included to indicate peak sound pressure should be flat weighted or unweighted within the generalized hearing range. The subscript associated with cumulative sound exposure level thresholds indicates the designated marine mammal auditory weighting function (LF, MF, and HF cetaceans, and PW and OW pinnipeds) and that the recommended accumulation period is 24 hours. The cumulative sound exposure level thresholds could be exceeded in a multitude of ways (*i.e.*, varying exposure levels and durations, duty cycle). When possible, it is valuable for action proponents to indicate the conditions under which these acoustic thresholds will be exceeded.

Ensonified Area

Here, we describe operational and environmental parameters of the activity that are used in estimating the area ensonified above the acoustic thresholds, including source levels and transmission loss coefficient.

In order to calculate the distances to the Level A harassment and the Level B harassment sound thresholds for the methods and piles being used in this project, NMFS used acoustic monitoring data from other locations to develop proxy source levels for various pile types (Table 6). Generally we choose source levels from similar pile types and locations (*e.g.*, geology, bathymetry) similar to the project. At this time,

NMFS is not aware of reliable source levels available for polymeric piles using vibratory pile installation, therefore source levels for timber pile driving were used as a proxy. Vibratory pile driving of polymeric piles expected to occur under the 2022 IHA has yet to occur and therefore has not been measured. Similarly, the following proxies were used as source levels for piles where no data was available: Source levels from the 48-inch (121.9-cm) steel pile from Naval Base Kitsap at Bangor, Washington (Caltrans 2020) was used as a proxy for 42 inch steel pipe piles (impact); the 30-inch steel pipe pile was used as a proxy for the 28-inch steel sheet pile (impact and vibratory); source levels for timber piles were used

as a proxy for concrete as they are expected to have similar sound levels as they are similarly sized, non-metallic, and will be removed using the same methods.

Very little information is available regarding source levels for in-water drilling activities associated with nearshore pile installation. Measurements made during a pile drilling project in 1–5 m (3–16 ft) depth at Santa Rosa Island, California, by Dazey *et al.* (2012) appear to provide the best available proxy source levels for activities. Dazey *et al.* (2012) reported average rms source levels ranging from 151 to 157 db re 1 μ Pa during 62 days that spanned all related drilling activities during a single season.

TABLE 6—PROJECT SOUND SOURCE LEVELS AND PROXY SOURCE LEVELS USED FOR ACOUSTIC MODELING

Pile type	Pile size (inch)	Method	Peak SPL (re 1 μ Pa (rms))	RMS SPL (re 1 μ Pa (rms))	SEL (re 1 μ Pa (rms))	Source
Steel Pipe Pile	42	Impact	213	190	177	Caltrans 2020.
		Vibratory	N/A	168	N/A	Sitka 2017.
Steel Sheet	28	Impact ¹	211	196	181	NAVFAC SW 2020.
		Vibratory ²	N/A	167	167	Navy 2015.
Concrete Pile	24	Impact	189	176	163	Illingworth and Rodkin 2017.
		Vibratory Removal ³	185	162	157	Caltrans 2020.
Concrete Pile	18	Impact ³	185	166	154	Caltrans 2020.
		Vibratory Removal ⁴	185	162	157	Caltrans 2020.
Polymeric Pile	13	Impact	177	153		Denes <i>et al.</i> , 2016.
		Vibratory ⁵	185	162	157	Caltrans 2020.
Timber Pile	14	Vibratory Install/Removal	185	162	157	Caltrans 2020.
N/A ⁶	“Multiple pile sizes” ⁶	Drilling	N/A	154	N/A	Dazey <i>et al.</i> , 2012.

¹ A source level value for impact pile driving of 28-inch steel sheet piles could not be found so a value for a 30-inch steel pipe pile has been used as a proxy (NAVFAC SW, 2020 [p.A–4]).

² A source level value for vibratory pile driving of 28-inch steel sheet piles could not be found so a value for a 30-inch steel pipe pile has been used as a proxy (Navy, 2015 [p. 14]).

³ Data on vibratory extraction of concrete piles is not available, however source levels are expected to be similar to the levels produced by timber piles as they are similar in size, material and removal method.

⁴ Proxy data for 18-inch octagonal piles.

⁵ Vibratory proxy for polymeric/plastic piles is unavailable; we assume SPL to be consistent with timber.

⁶ See Table 2 for pile types/size that may use drilling, as needed.

TABLE 7—SOURCE LEVEL MATRIX FOR CONCURRENT ACTIVITIES

Pile diameter		42-inch steel pipe	28-inch steel pipe	14-inch timber	14-inch polymeric	24-inch concrete	18-inch concrete	14-inch timber	Multiple
42-inch Steel Pipe	SSL	168	167	162	162	162	162	162	154
	168	171	171	169	169	169	169	169	168
28-inch Steel Pipe	167	171	170	168	168	168	168	168	167
14-inch Timber	162	169	168	165	165	165	165	165	163
14-inch Polymeric	162	169	168	165	165	165	165	165	163
24-inch Concrete	162	169	168	165	165	165	165	165	163
18-inch Concrete	162	169	168	165	165	165	165	165	163
14-inch Timber	162	169	168	165	165	165	165	165	163
Multiple	154	168	167	163	163	163	163	163	157

The ensonified area associated with Level A harassment is more technically challenging to predict due to the need to account for a duration component. Therefore, NMFS developed an optional

User Spreadsheet tool to accompany the Technical Guidance (2018) that can be used to relatively simply predict an isopleth distance for use in conjunction with marine mammal density or

occurrence to help predict potential takes.

We note that because of some of the assumptions included in the methods underlying this optional tool, we

anticipate that the resulting isopleth estimates are typically going to be overestimates of some degree, which may result in an overestimate of potential take by Level A harassment. However, this optional tool offers the best way to estimate isopleth distances when more sophisticated modeling methods are not available or practical.

For stationary sources, such as pile driving, removal, and drilling, the optional User Spreadsheet tool predicts the distance at which, if a marine mammal remained at that distance for the duration of the activity, it would be expected to incur PTS. Inputs used in the optional User Spreadsheet tool are reported in Table 1 and Table 2, and

source levels used in the User Spreadsheet are reported in Table 6. The resulting isopleths are reported in Table 7 (impact pile driving), Table 8 (vibratory pile driving/removal, and drilling), and Table 9 (concurrent pile driving scenarios) below.

TABLE 8—LEVEL A AND LEVEL B HARASSMENT ISOPLETHS FOR IMPACT PILE DRIVING

Year	Pile driving site	Source	Level A harassment isopleths (m)				Level B (behavioral) (m)
			LF	MF	HF	Phocids	
Year 2	CEP-176	42-inch Steel Pipe	1482	53	1766	793	1,000
		28-inch Steel Sheets	1783	63	2123	954	2512
	CEP-175	13-inch Polymeric Piles	17	1	20	9	3
	CEP-102	24-inch Square Precast Concrete	117	4	139	63	117
		18-inch Square Precast Concrete	7	0	9	4	25
Year 3	Pier 3 (bearing piles)	24-inch Square Precast Concrete	254	9	302	136	117
	Pier 3 (Fender Piles)	24-inch Square Precast Concrete	37	1	44	20	117
		18-inch Steel Pipe	661	24	788	354	25
	CEP-102	42-inch Steel Pipe	1002	36	1193	536	1000
		28-inch Steel Sheet	1783	63	2123	954	2512
Year 4	CEP-102	24-inch Square Precast Concrete	117	4	139	63	117
		18-inch Square Precast Concrete	7	0	9	4	25
		42-inch Steel Pipe	1002	36	1193	536	1000
		28-inch Steel Sheet	1783	63	2123	954	2512
Year 5	CEP-102	24-inch Square Precast Concrete	117	4	139	63	117
		18-inch Square Precast Concrete	7	0	9	4	25

TABLE 9—LEVEL A AND LEVEL B HARASSMENT ISOPLETHS FOR VIBRATORY PILE DRIVING, REMOVAL, AND DRILLING

Year	Pile driving site	Source	Level A harassment isopleths (m) ¹				Level B behavioral (m)	
			LF	MF	HF	Phocids		
Year 2	CEP-176	42-inch Steel Pipe (Vibratory)	127	11	188	77	15,849	
		28-inch Steel Sheet (Vibratory)	100	9	147	61	13,594	
	CEP-175	13-inch Polymeric Piles (Vibratory)	15	1	22	9	6,310	
	CEP-102	24-inch Square Precast Concrete (Drilling)	1	0	1	0	1,848	
		18-inch Square Precast Concrete (Drilling)	1	0	1	0	1,848	
Year 3	Pier 3 (Fender Piles)	24-inch Square Precast Concrete (Drilling)	1	0	1	1	1,848	
	CEP-102	42-inch Steel Pipe (Vibratory Install)	80	7	118	49	15,849	
		28-inch Steel Sheet Piles (Vibratory)	100	9	147	61	13,594	
		18-inch Square Precast Concrete (Vibratory Extrac- tion).	35	3	51	21	6,310	
	Year 4	CEP-102	24-inch Square Precast Concrete (Drilling)	1	0	1	0	1,848
14-inch Timber (Vibratory Extraction)			68	6	101	41	6,310	
18-inch Square Precast Concrete (Drilling)			1	0	1	0	1,848	
42-inch Steel Pipe (Vibratory)			80	7	118	49	15,849	
28-inch Steel Sheet (Vibratory)			100	9	147	61	13,594	
18-inch Square Precast Concrete (Vibratory Extrac- tion).			35	3	51	21	6,310	
Existing Pier 3		24-inch Square Precast Concrete (Vibratory Extrac- tion).	42	4	62	25	6,310	
		16-inch and 18-inch Square Precast Concrete (Vi- bratory Extraction).	37	3	55	23	6,310	
Year 5		CEP-102	24-inch Square Precast Concrete (Drilling)	1	0	1	0	1,848
		Existing Pier 3	18-inch Square Precast Concrete (Drilling)	1	0	1	0	1,848
	16-inch and 18-inch Square Precast Concrete (Vi- bratory Extraction).		37	3	55	23	6,310	

TABLE 10—LEVEL A AND LEVEL B HARASSMENT ISOPLETHS FOR CONCURRENT PILE DRIVING AND DRILLING SCENARIOS

Year	Pile driving site	Source	Level A harassment isopleths (m) ¹				Level B behavioral (m)
			LF	MF	HF	Phocids	
2	CEP-176 Bulkhead	Install of 42-inch steel pipe and 28-inch steel sheets	549	49	811	334	25,119
2	CEP-176 Bulkhead	Install of two 42-inch steel pipe piles	320	28	472	194	25,119
2	CEP-176 and CEP-102 ..	Install of 42-inch steel pipe and 24-inch Square precast concrete.	166	15	246	101	15,849
2	CEP-176 and CEP-175 ..	Install of 42-inch steel pipe piles and 13-inch polymeric piles.	254	23	376	155	18,478
3	Pier 3	Install of 24-inch Square precast concrete fender piles using two drills.	2	0.1	2	1	2,929
3	CEP-102 Bulkhead	Install of 42-inch steel pipe and 28-inch steel sheets	507	45	750	308	25,119

TABLE 10—LEVEL A AND LEVEL B HARASSMENT ISOPLETHS FOR CONCURRENT PILE DRIVING AND DRILLING SCENARIOS—Continued

Year	Pile driving site	Source	Level A harassment isopleths (m) ¹				Level B behavioral (m)
			LF	MF	HF	Phocids	
4	Existing Pier 3 CEP-102 Platform.	Extraction of 14-inch timber piles, install of 42-inch steel pipe and 28-inch steel sheets, and rotary drilling of 24-inch Square precast concrete.	981	87	1450	596	25,119
5	Existing Pier 3 CEP-102 Platform.	Concurrent extraction of 16- and 18-inch Square precast concrete and rotary drilling of 24-inch Square precast concrete.	77	7	114	47	7,356

The maximum distance to the Level A harassment threshold during construction would be during the impact driving of 28-inch (71-cm) steel sheets at CEP-176 and CEP-102 (1,783 m for humpback whale; 63 m for bottlenose dolphin; 2,123 m for harbor porpoises; and 954 m for pinnipeds). The largest calculated Level B harassment isopleth extends out to 25,119 m, which would result from concurrent pile driving of the scenarios presented in Table 10. While 25,119 m may not be an attainable observable distance in all directions, the Level B harassment zone will be monitored to the maximum extent possible.

Marine Mammal Occurrence and Take Estimation

In this section we provide information about the presence, density, or group dynamics of marine mammals that will inform the take calculations. We describe how the information provided above is brought together to produce a quantitative take estimate for each species.

Humpback Whale

Humpback whales occur in the mouth of the Chesapeake Bay and nearshore waters of Virginia during winter and spring months. Several satellite tagged humpback whales were detected west of the Chesapeake Bay Bridge Tunnel, including two individuals with locations near NAVSTA Norfolk and Joint Expeditionary Base Little Creek (Aschettino *et al.*, 2017). Group size was not reported in these surveys, however most whales detected were juveniles. Although two individuals were detected in the vicinity of the project activities, there is no evidence that they linger for multiple days. Because no density estimates are available for the species in this area, the Navy estimated one potential sighting of a group of average size (two individuals) every 60 days of pile driving. Therefore, given the number of project days expected in each year (Table 1), NMFS has authorized a total of 19 takes by Level B harassment of humpback whale over the 5-year

authorization, with no more than 7 takes by Level B harassment in a given year.

The largest Level A harassment zone for low-frequency cetaceans extends approximately 1,783 m from the source during impact pile driving of the 28-inch steel sheet piles (Table 8). The Navy will shut down if a humpback whale is sighted within any of the Level A harassment zones for all activities, as indicated in Table 11. Therefore, the Navy did not request, and NMFS did not authorize, take by Level A harassment of humpback whales.

Bottlenose Dolphin

The expected number of bottlenose dolphins in the project area was estimated using inshore seasonal densities provided in Engelhaupt *et al.* (2016) from vessel line-transect surveys near NAVSTA Norfolk and adjacent areas near Virginia Beach, Virginia, from August 2012 through August 2015 (Engelhaupt *et al.*, 2016). This density includes sightings inshore of the Chesapeake Bay from NAVSTA Norfolk west to the Thimble Shoals Bridge, and is the most representative density for the project area. To calculate potential Level B harassment takes of bottlenose dolphin, NMFS conservatively multiplied the density of 1.38 dolphins per square kilometer (/km²) (from Engelhaupt *et al.*, 2016) by the largest Level B harassment isopleth for each project location (Table 8, 9, and 10), and then by the number of days associated with that activity (Table 1). For example, to calculate Level B harassment takes associated with work at the existing Pier 3 in year 2, NMFS multiplied the density (1.38 dolphins/km²) by the largest Level B harassment zone for impact pile driving on the 24-inch concrete bearing piles at the new Pier 3 (0.043 km²) by the proportional number of pile driving days for that activity (70 days) for a total of 4 Level B harassment takes at Pier 3, for that activity in year 1. Takes by Level B harassment were calculated for both individual pile driving activities and concurrent pile driving activities, as authorized takes are conservatively

based on the scenario that produces more takes by Level B harassment (Table 11). Therefore, NMFS authorized 28,480 ¹ takes by Level B harassment of bottlenose dolphin across all 5 years, with no more than 13,190 takes in a given year.

Harbor Porpoise

Harbor porpoises are known to occur in the coastal waters near Virginia Beach (Hayes *et al.*, 2019). Density data for this species within the project vicinity do not exist or were not calculated because sample sizes were too small to produce reliable estimates of density. Harbor porpoise sighting data collected by the U.S. Navy near NAVSTA Norfolk and Virginia Beach from 2012 to 2015 (Engelhaupt *et al.*, 2014; 2015; 2016) did not produce enough sightings to calculate densities. One group of two harbor porpoises was seen during spring 2015 (Engelhaupt *et al.*, 2016). Elsewhere in their range, harbor porpoises typically occur in groups of two to three individuals (Carretta *et al.*, 2001; Smultea *et al.*, 2017).

Because there are no density estimates for the species in the project area, the Navy conservatively estimated one harbor porpoise sighting (of two individuals) once every 60 days of pile driving or drilling. Therefore, the assumption of two individuals per 60 days was used for calculation of take numbers. Total pile driving days for Year 2 will be 185 days, Year 3 will be 92 days, Year 4 will be 204 days, and Year 5 will have 32 days. Takes by Level B harassment were calculated for both individual pile driving activities and concurrent pile driving activities, as authorized takes are conservatively based on the scenario that produced the larger exposure estimate (Table 11). Using the above methodology, NMFS

¹ Note: This total number of takes by Level B harassment authorized differs from that in the Navy's request for rulemaking. The number presented here conservatively uses exposure estimates for concurrent pile driving scenarios in Year 5, which were higher than those produced for individual pile driving activities.

calculated an exposure estimate of 19 incidents of take for harbor porpoises.

The largest Level A harassment zone for high-frequency cetaceans is 2,123 m during impact pile driving of the 28-inch steel sheet piles. The Navy will shut down at 500 m for harbor porpoises during the aforementioned activity, in addition to shorter distances where appropriate for other activities as noted in Table 13 as a reasonable area to observe for harbor porpoises and implement shutdown procedures while avoiding an impracticable number of shutdowns. Consequently, the Navy has requested authorization of take by Level A harassment for harbor porpoise during the course of the project. Take by Level A harassment may not actually occur due to the duration of time harbor porpoise would be required to remain within the Level A harassment zone to accumulate enough energy to experience PTS. However, as a precaution NMFS authorized a total of 4 takes by Level A harassment as requested by the Navy (Table 11) with no more than 2 takes by Level A harassment occurring in a given year, and 15 total takes by Level B harassment with no more than 5 takes by Level B harassment occurring in a given year, equaling the aforementioned total of 19 takes over 5 years.

Harbor Seal

The expected number of harbor seals in the project area was estimated using systematic land- and vessel-based

survey data for in-water and hauled out seals collected by the Navy at the Chesapeake Bay Bridge Tunnel rock armor and portal islands from 2014 through 2019 (Jones *et al.*, 2020). The average daily seal count from the field season ranged from 8 to 23 seals, with an average of 13.6 harbor seals across all the field seasons.

The Navy expects, and NMFS concurs, that harbor seals are likely to be present from November to April. Consistent with previous nearby projects (87 FR 15945, March 31, 2022; 86 FR 24340, May 6, 2021; 86 FR 17458, April 2, 2021), NMFS calculated take by Level B harassment by multiplying 13.6 seals by the number of pile driving days expected to occur from November through April (seal season): 74 days in Year 2, 23 days in Year 3, 133 days in Year 4, and 32 days in Year 5. Potential takes by Level A harassment were calculated based on the number of production days within seal season on which the Level A harassment isopleth exceeds the shutdown zone of 200 m (42 days in Year 2; 3 days in Year 3; and 0 days in Year 4 and 5), assuming that approximately 10 percent of harbor seal exposures would be at or above the Level A harassment threshold. Potential takes by Level B harassment were calculated by subtracting the Level A harassment takes estimated per year from the total calculated takes. Consistent with previous species, take estimates are based on the scenario (individual or concurrent) that

produced the higher take estimate (Table 11). Therefore, the Navy requested and NMFS authorized a total of 4,182 takes by Level B harassment and 61 takes by Level A harassment (Table 12).

Gray Seal

Very little information is available about the occurrence of gray seals in the Chesapeake Bay and coastal waters. Although the U.S. population of gray seals may be increasing, there are only a few records available at the known haulout sites in Virginia used by gray seals, strandings are rare, and they have not been reported in shipboard surveys. Assuming that they may utilize the Chesapeake Bay waters, the Navy conservatively estimates one gray seal may be exposed to elevated noise levels for every 60 days of vibratory pile driving during the 6-month period when they are most likely to be present. Similar to harbor seals, the maximum number of pile driving days where gray seals may be exposed during seal season per year were used for calculations. The scenario (concurrent or individual activities) that produced the larger exposure estimate is authorized (Table 11). Therefore, the Navy requested and NMFS authorized five takes by Level B harassment. Given the low likelihood of encountering gray seals during the project and low number of days in which Level A harassment isopleths may exceed shutdown zones, no take by Level A harassment is authorized.

TABLE 11—CALCULATED TAKES BY LEVEL A AND LEVEL B HARASSMENT FOR CONCURRENT AND INDIVIDUAL PILE DRIVING, REMOVAL, AND DRILLING SCENARIOS ¹

Year	Species	Individual activities		Concurrent activities	
		Level A	Level B	Level A	Level B
2	Humpback whale	0	6	0	2
	BND—Northern Migratory	0	2,691	0	5,609
	BND—Southern Migratory				
	BND—NC Estuarine				
	Harbor porpoise	2	4	0	1
	Harbor seal	57	949	25	832
3	Gray seal	0	1	0	1
	Humpback whale	0	3	0	1
	BND—Northern Migratory	0	3,061	0	1,440
	BND—Southern Migratory				
	BND—NC Estuarine				
	Harbor porpoise	0	3	0	1
4	Harbor seal	4	309	7	537
	Gray seal	0	0	0	1
	Humpback whale	0	7	0	1
	BND—Northern Migratory	0	13,190	0	3,023
	BND—Southern Migratory				
	BND—NC Estuarine				
5	Harbor porpoise	2	5	0	1
	Harbor seal	0	1,809	26	232
	Gray seal	0	2	0	0
	Humpback whale	0	2	0	3
	BND—Northern Migratory	0	383	0	6,620
	BND—Southern Migratory				
	BND—NC Estuarine				

TABLE 11—CALCULATED TAKES BY LEVEL A AND LEVEL B HARASSMENT FOR CONCURRENT AND INDIVIDUAL PILE DRIVING, REMOVAL, AND DRILLING SCENARIOS ¹—Continued

Year	Species	Individual activities		Concurrent activities	
		Level A	Level B	Level A	Level B
Harbor porpoise		0	1	0	3
	Harbor seal	0	435	0	1,115
	Gray seal	0	2	0	1

¹ Potential takes by Level A and Level B harassment are conservatively based on the scenario (individual vs. concurrent pile driving, removal, or drilling) that produced the highest exposure estimate. Therefore, the number of takes by Level A and Level B harassment authorized is *italicized* and used to determine percent of stock.

TABLE 12—AUTHORIZED TAKES BY LEVEL A AND LEVEL B HARASSMENT BY SPECIES AND STOCK IN COMPARISON TO STOCK ABUNDANCE

Year	Species	Abundance	Take		Total	Percent of stock
			Level A	Level B		
2	Humpback whale ^a	1,396	0	6	6	0.43
	BND—Northern Migratory ^{b c}	6,639	0	5,609	2,705	40.74
	BND—Southern Migratory ^{b c}	3,751			2,705	72.10
	BND—NC Estuarine ^{b c}	823			200	24.30
	Harbor porpoise	95,543	2	4	6	0.01
	Harbor seal	61,336	57	949	1,006	1.64
	Gray seal	27,300	0	1	1	0.00
3	Humpback whale ^a	1,396	0	3	3	0.21
	BND—Northern Migratory ^{b c}	6,639	0	3,061	1,431	21.55
	BND—Southern Migratory ^{b c}	3,751			1,431	38.15
	BND—NC Estuarine ^{b c}	823			200	24.30
	Harbor porpoise	95,543	0	3	3	0.00
	Harbor seal	61,336	7	537	544	0.89
	Gray seal	27,300	0	1	1	0.00
4	Humpback whale ^a	1,396	0	7	7	0.50
	BND—Northern Migratory ^{b c}	6,639	0	13,190	6,495	97.83
	BND—Southern Migratory ^{b c}	3,751			6,495	173.15
	BND—NC Estuarine ^{b c}	823			200	24.30
	Harbor porpoise	95,543	2	5	7	0.01
	Harbor seal	61,336	26	1,783	1,809	2.95
	Gray seal	27,300	0	2	2	0.01
5	Humpback whale ^a	1,396	0	3	3	0.21
	BND—Northern Migratory ^{b c}	6,639	0	6,620	3,210	48.35
	BND—Southern Migratory ^{b c}	3,751			3,210	85.58
	BND—NC Estuarine ^{b c}	823			200	24.30
	Harbor porpoise	95,543	0	3	3	0.00
	Harbor seal	61,336	0	1,115	1,115	1.82
	Gray seal	27,300	0	2	2	0.01

^a West Indies DPS. Please see the Description of Marine Mammals in the Area of Specified Activities Section for further discussion.

^b Take estimates are weighted based on calculated percentages of population for each distinct stock, assuming animals present will follow the same probability of presence in the project area. Please see Small Numbers section for additional information.

^c Assumes multiple repeated takes of the same individuals from a small portion of each stock as well as repeated takes of Chesapeake Bay resident population (size unknown). Please see Small Numbers section for additional information.

Mitigation

In order to issue an LOA under section 101(a)(5)(A) of the MMPA, NMFS must set forth the permissible methods of taking pursuant to the activity, and other means of effecting the least practicable impact on the species or stock and its habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stock for taking for certain subsistence uses (latter not applicable for this action). NMFS regulations require applicants for incidental take

authorizations to include information about the availability and feasibility (economic and technological) of equipment, methods, and manner of conducting the activity or other means of effecting the least practicable adverse impact upon the affected species or stocks, and their habitat (50 CFR 216.104(a)(11)).

In evaluating how mitigation may or may not be appropriate to ensure the least practicable adverse impact on species or stocks and their habitat, as well as subsistence uses where applicable, NMFS considers two primary factors:

(1) The manner in which, and the degree to which, the successful implementation of the measure(s) is expected to reduce impacts to marine mammals, marine mammal species or stocks, and their habitat. This considers the nature of the potential adverse impact being mitigated (likelihood, scope, range). It further considers the likelihood that the measure will be effective if implemented (probability of accomplishing the mitigating result if implemented as planned), the likelihood of effective implementation (probability implemented as planned); and,

(2) The practicability of the measures for applicant implementation, which may consider such things as cost, and impact on operations.

In addition to the measures described later in this section, the Navy will employ the following mitigation measures:

- The Navy will conduct briefings between construction supervisors and crews, the marine mammal monitoring team, and Navy staff prior to the start of all pile driving activity and when new personnel join the work, to explain responsibilities, communication procedures, marine mammal monitoring protocol, and operational procedures;

- If a marine mammal comes within 10 m of construction activities, including in-water heavy machinery work not being analyzed in this rule, operations shall cease and vessels shall reduce speed to the minimum level required to maintain steerage and safe working conditions;

- Pile driving activity must be halted upon observation of either a species for which incidental take is not authorized or a species for which incidental take has been authorized but the authorized number of takes has been met, entering or is within the harassment zone.

The following mitigation measures apply to the Navy's in-water construction activities.

Establishment of Shutdown Zones—The Navy will establish shutdown zones for all pile driving and removal and drilling activities. The purpose of a shutdown zone is generally to define an area within which shutdown of the activity will occur upon sighting of a marine mammal (or in anticipation of an animal entering the defined area). Shutdown zones will vary based on the

activity type and marine mammal hearing group (Table 13).

Protected Species Observers (PSOs)—The placement of PSOs during all pile driving and removal and drilling activities (described in the Monitoring and Reporting section) will ensure that the entire shutdown zone is visible. Should environmental conditions deteriorate such that the entire shutdown zone would not be visible (e.g., fog, heavy rain), pile driving and removal and drilling must be delayed until the PSO is confident marine mammals within the shutdown zone could be detected.

Monitoring for Level A and B Harassment—The Navy will monitor the Level B harassment zones (areas where SPLs are equal to or exceed the 160 dB rms threshold for impact pile driving, and the 120 dB rms threshold during drilling and vibratory pile driving and removal) and Level A harassment zones to the extent practicable, and all of the shutdown zones, during all pile driving, removal or drilling days. Monitoring zones provide utility for observing by establishing monitoring protocols for areas adjacent to the shutdown zones. Monitoring zones enable PSOs to be aware of and communicate the presence of marine mammals in the project area outside the shutdown zone and thus prepare for a potential cessation of activity should the animal enter the shutdown zone.

Pre-activity Monitoring—Prior to the start of daily in-water construction activity, or whenever a break in pile driving/removal of 30 minutes or longer occurs, PSOs will observe the shutdown and monitoring zones for a period of 30 minutes. The shutdown zone will be

considered cleared when a marine mammal has not been observed within the zone for that 30-minute period. If a marine mammal is observed within the shutdown zones listed in Table 13, pile driving and drilling activity must be delayed or halted. If pile driving and/or drilling is delayed or halted due to the presence of a marine mammal, the activity may not commence or resume until either the animal has voluntarily exited and been visually confirmed beyond the shutdown zones or 15 minutes have passed without re-detection of the animal. When a marine mammal for which Level B harassment take is authorized is present in the Level B harassment zone, activities may begin. If work ceases for more than 30 minutes, the pre-activity monitoring of the shutdown zones will commence. A determination that the shutdown zone is clear must be made during a period of good visibility (*i.e.*, the entire shutdown zone and surrounding waters must be visible to the naked eye).

Soft Start—Soft-start procedures are used to provide additional protection to marine mammals by providing warning and/or giving marine mammals a chance to leave the area prior to the hammer operating at full capacity. For impact pile driving, contractors will be required to provide an initial set of three strikes from the hammer at reduced energy, followed by a 30-second waiting period, then two subsequent reduced-energy strike sets. Soft start will be implemented at the start of each day's impact pile driving and at any time following cessation of impact pile driving for a period of 30 minutes or longer.

TABLE 13—SHUTDOWN ZONES ¹

LOA year	Pile type, size, and driving method	Shutdown distance (m) for humpback whales	Shutdown distance (m) for harbor porpoise	Shutdown distance (m) for all other species	Level B (behavioral) harassment distance (m) all marine mammals
Year 2	Impact Install 42-inch steel pipe piles	1,490	500	200	1,000
	Vibratory Install 42-inch steel pipe piles	140	200	70	2,500
	Impact Install 28-inch steel sheet piles	1,790	500	200	2,500
	Vibratory Install 28-inch steel sheet piles	110	150	80	2,500
	Impact Install 13-inch polymeric piles	20	30	30	30
	Vibratory Install 13-inch polymeric piles	20	30	30	2,500
	Impact Install 24-inch precast concrete bearing piles	260	500	200	117
	Impact Install 18-inch precast concrete fender piles	10	10	10	30
	Pre-drilling	10	10	10	2,500
	Impact Install 24-inch precast concrete fender piles	40	50	30	120
Year 3	Impact Install 18-inch steel piles	700	500	200	30
	Impact Install 42-inch steel pipe piles	1,010	500	200	1,000
	Vibratory Install 42-inch steel pipe piles	90	120	50	2,500
	Impact Install 28-inch steel sheet piles	1,790	500	200	2,500
	Vibratory Install 28-inch steel sheet piles	110	150	70	2,500
	Vibratory Extract 18-inch precast concrete fender piles	40	60	30	2,500
	Pre-drilling	10	10	10	2,500

TABLE 13—SHUTDOWN ZONES ¹—Continued

LOA year	Pile type, size, and driving method	Shutdown distance (m) for humpback whales	Shutdown distance (m) for harbor porpoise	Shutdown distance (m) for all other species	Level B (behavioral) harassment distance (m) all marine mammals
Year 4	Impact Install 24-inch precast concrete bearing piles	120	150	70	120
	Vibratory Extract 14-inch timber piles	70	110	50	2,500
	Impact Install 18-inch precast concrete fender piles	10	10	10	30
	Impact Install 42-inch steel pipe piles	1,010	500	200	1,000
	Vibratory Install 42-inch steel pipe piles	90	120	50	2,500
	Vibratory Extract 24-inch concrete fender piles	50	70	30	2,500
	Impact Install 28-inch steel sheet piles	1,790	500	200	2,500
	Vibratory Install 28-inch steel sheet piles	120	150	70	2,500
	Vibratory Extract 18-inch precast concrete fender piles	40	60	30	2,500
	Vibratory Extract 16- to 18-inch precast concrete bearing piles	40	60	30	2,500
	Pre-drilling	10	10	10	2,500
Year 5	Vibratory Extract 16- to 18-inch precast concrete bearing piles	40	60	30	2,500
	Impact Install 24-inch precast concrete bearing piles	120	150	70	120
	Impact Install 18-inch precast concrete fender piles	10	10	10	30
	Pre-drilling	10	10	10	2,500

¹ Calculated Level A harassment isopleths for concurrent pile driving were smaller than those calculated for individual impact pile driving, vibratory pile driving and removal, and drilling. Therefore, shutdown zones conservatively reflect individual activity.

Based on our evaluation of the applicant's measures, as well as other measures considered by NMFS, NMFS has determined that the mitigation measures provide the means of effecting the least practicable impact on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance.

Monitoring and Reporting

In order to issue an LOA for an activity, section 101(a)(5)(A) of the MMPA states that NMFS must set forth requirements pertaining to the monitoring and reporting of such taking. The MMPA implementing regulations at 50 CFR 216.104(a)(13) indicate that requests for authorizations must include the suggested means of accomplishing the necessary monitoring and reporting that will result in increased knowledge of the species and of the level of taking or impacts on populations of marine mammals that are expected to be present while conducting the activities. Effective reporting is critical both to compliance as well as ensuring that the most value is obtained from the required monitoring.

Monitoring and reporting requirements prescribed by NMFS should contribute to improved understanding of one or more of the following:

- Occurrence of marine mammal species or stocks in the area in which take is anticipated (*e.g.*, presence, abundance, distribution, density);
- Nature, scope, or context of likely marine mammal exposure to potential stressors/impacts (individual or

cumulative, acute or chronic), through better understanding of: (1) action or environment (*e.g.*, source characterization, propagation, ambient noise); (2) affected species (*e.g.*, life history, dive patterns); (3) co-occurrence of marine mammal species with the activity; or (4) biological or behavioral context of exposure (*e.g.*, age, calving or feeding areas);

- Individual marine mammal responses (behavioral or physiological) to acoustic stressors (acute, chronic, or cumulative), other stressors, or cumulative impacts from multiple stressors;
- How anticipated responses to stressors impact either: (1) long-term fitness and survival of individual marine mammals; or (2) populations, species, or stocks;
- Effects on marine mammal habitat (*e.g.*, marine mammal prey species, acoustic habitat, or other important physical components of marine mammal habitat); and,
- Mitigation and monitoring effectiveness.

The Navy will submit a Marine Mammal Monitoring Plan to NMFS for approval in advance of the start of construction.

Visual Monitoring

- Marine mammal monitoring during pile driving and removal must be conducted by qualified, NMFS approved PSOs, in accordance with the following: PSOs must be independent of the activity contractor (for example, employed by a subcontractor) and have no other assigned tasks during monitoring periods;

- At least one PSO must have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization;

- Other PSOs may substitute other relevant experience, education (degree in biological science or related field), or training for prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization;

- PSOs must be approved by NMFS prior to beginning any activity subject to this rulemaking; and

- Where a team of three or more PSOs is required, a lead PSO or monitoring coordinator must be designated. The lead PSO must have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization.

PSOs must have the following additional qualifications:

- Ability to conduct field observations and collect data according to assigned protocols;
- Experience or training in the field identification of marine mammals, including the identification of behaviors;
- Sufficient training, orientation, or experience with the construction operation to provide for personal safety during observations;
- Writing skills sufficient to prepare a report of observations including but not limited to the number and species of marine mammals observed; dates and times when in-water construction activities were conducted; dates, times, and reason for implementation of

mitigation (or why mitigation was not implemented when required); and marine mammal behavior; and

- Ability to communicate orally, by radio or in person, with project personnel to provide real-time information on marine mammals observed in the area as necessary.

The Navy must establish the following monitoring locations and visual monitoring of the entire shutdown zones must occur for all pile driving and drilling activities. For all pile driving activities, a minimum of one PSO must be assigned to the active pile driving or drilling location to monitor the shutdown zones and as much of the Level A and Level B harassment zones as possible. If the active project location includes demolition activities, then the next adjacent pier may be used as an appropriate monitoring location

ensuring that the aforementioned criteria is met. Monitoring must be conducted by a minimum of three PSOs for any activity with an associated harassment isopleth over 1,000 m. All other activities will require a minimum of two PSOs. For activities in Tables 8, 9, and 10, with Level B harassment zones larger than 3,000 m, at least one PSO must be stationed on either Pier 14 or the North Jetty to monitor the part of the zone exceeding the edge of the Norfolk Naval Station (see Figure 3). The third PSO for activities whose harassment isopleths exceed 1,000 m will be located on Pier 1. PSOs will be placed at the best vantage point(s) practicable to monitor for marine mammals and implement shutdown/delay procedures (See Figure 3 for representative monitoring locations). If changes are necessary to ensure full coverage of the shutdown zones, the

Navy shall contact NMFS to alter PSO locations (e.g., vessel blocking view from pier locations). Additionally, the shutdown/monitoring zones may be modified with NMFS' approval following NMFS' acceptance of an acoustic monitoring report.

Monitoring will be conducted 30 minutes before, during, and 30 minutes after all in water construction activities. In addition, PSOs shall record all incidents of marine mammal occurrence, regardless of distance from activity, and shall document any behavioral reactions in concert with distance from drilling or piles being driven or removed. Pile driving activities include the time to install or remove a single pile or series of piles, as long as the time elapsed between uses of the pile driving equipment is no more than 30 minutes.

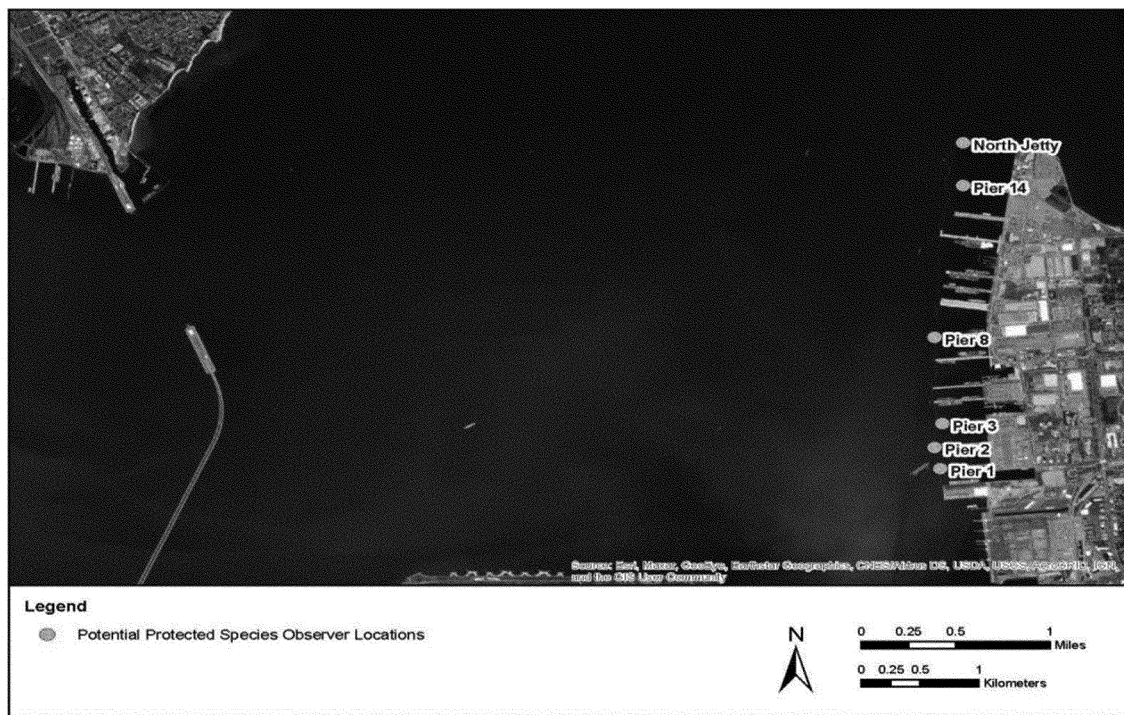


Figure 3 -- Protected Species Observer Locations at Naval Station Norfolk at Norfolk, Virginia

Acoustic Monitoring

The Navy plans to implement *in situ* acoustic monitoring efforts to measure SPLs from in-water construction activities for pile types and methods that have not been previously collected at NAVSTA Norfolk (Table 14). The

Navy will collect and evaluate acoustic sound recording levels during pile driving activities. Hydrophones will be placed at locations 33 ft from the noise source and, where the potential for Level A (PTS onset) harassment exists, at a second representative monitoring

location that is a distance of 20 times the depth of water at the pile location. For the pile driving events acoustically measured, 100 percent of the data will be analyzed. Please see the Navy's Marine Mammal Monitoring Plan and application for additional detail.

Table 14 -- Hydroacoustic Monitoring Summary

<i>Pile Type¹</i>	<i>Count²</i>	<i>Method of Install/Removal²</i>	<i>Number Monitored²</i>
18-inch/24-inch concrete	614	Pre-Drilling	5
13-inch Polymeric	9	Vibratory	5
13-inch Polymeric	9	Impact	5
14-inch timber	624	Vibratory Extract	10
16-inch or 18-inch concrete	903	Vibratory Extract	10
18-inch steel pipe	18	Impact	5
18-inch concrete	93	Impact	10
18-inch concrete	62	Vibratory Extract	10
24-inch concrete	1,063	Impact	10
24-inch concrete	72	Vibratory Extract	10
42-inch steel pipe	179	Vibratory	10
42-inch steel pipe	179	Impact	10
28-inch steel sheet	376	Vibratory	10
28-inch steel sheet	376	Impact	10

1. Data has previously been collected on the impact driving of 24-inch concrete piles and timber piles at NAVSTA Norfolk; therefore, no additional data collection will occur for these pile types.
2. Some piles may be either vibratory or pile driving, or a combination of both. Pre-drilling may not be utilized if site conditions do not require it. The hydroacoustic report at the end of construction will clarify which installation method was utilized and monitored for each pile type.

Environmental data shall be collected, including but not limited to, the following: wind speed and direction, air temperature, humidity, surface water temperature, water depth, wave height, weather conditions, and other factors that could contribute to influencing underwater sound levels (*e.g.*, aircrafts, boats, etc.).

Reporting

The Navy is required to submit an annual report on all activities and marine mammal monitoring results to NMFS within 90 days following the end of each construction year. Additionally, a draft comprehensive 5-year summary report must be submitted to NMFS within 90 days of the end of the project. The annual reports will include an overall description of work completed, a narrative regarding marine mammal sightings, and associated PSO data sheets. Specifically, the report must include:

- Dates and times (begin and end) of all marine mammal monitoring;
- Construction activities occurring during each daily observation period, including: (a) how many and what type of piles were driven or removed and the method (*i.e.*, impact or vibratory); and (b) the total duration of time for each pile (vibratory driving) or hole (drilling)

and number of strikes for each pile (impact driving);

- PSO locations during marine mammal monitoring; and
- Environmental conditions during monitoring periods (at beginning and end of PSO shift and whenever conditions change significantly), including Beaufort sea state and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon, and estimated observable distance.

Upon observation of a marine mammal the following information must be reported:

- Name of PSO who sighted the animal(s) and PSO location and activity at the time of sighting;
- Time of sighting;
- Identification of the animal(s) (*e.g.*, genus/species, lowest possible taxonomic level, or unidentified), PSO confidence in identification, and the composition of the group if there is a mix of species;
- Distance and location of each observed marine mammal relative to the pile being driven or hole being drilled for each sighting;
- Estimated number of animals (min/max/best estimate);
- Estimated number of animals by cohort (adults, juveniles, neonates, group composition, *etc.*);

- Description of any marine mammal behavioral observations (*e.g.*, no response or changes in behavioral state such as ceasing feeding, changing direction, flushing, or breaching);
- Number of marine mammals detected within the harassment zones, by species; and
- Detailed information about implementation of any mitigation (*e.g.*, shutdowns and delays), a description of specified actions that ensued, and resulting changes in behavior of the animal(s), if any.

The acoustic monitoring report must contain the informational elements described in the Marine Mammal Monitoring Plan and, at minimum, must include:

- Hydrophone equipment and methods: Recording device, sampling rate, distance (m) from the pile where recordings were made; depth of water and recording device(s);
- Type and size of pile being driven, substrate type, method of driving during recordings (*e.g.*, hammer model and energy), and total pile driving duration;
- Whether a sound attenuation device is used and, if so, a detailed description of the device used and the duration of its use per pile;
- For impact pile driving and/or drilling (per pile): number of strikes and strike rate; depth of substrate to penetrate; pulse duration and mean,

median, and maximum sound levels (dB re: 1 μ Pa); root mean square sound pressure level (SPL_{rms}); cumulative sound exposure level (SEL_{cum}), peak sound pressure level (SPL_{peak}), and single-strike sound exposure level (SEL_{s-s}); and

- For vibratory driving/removal and/or drilling (per pile): duration of driving per pile; mean, median, and maximum sound levels (dB re: 1 μ Pa); Root mean square sound pressure level (SPL_{rms}), cumulative sound exposure level (SEL_{cum}), and timeframe over which the sound is averaged.

If no comments are received from NMFS within 30 days, the draft reports will constitute the final reports. If comments are received, a final report addressing NMFS' comments must be submitted within 30 days after receipt of comments. All PSO datasheets and/or raw sighting data must be submitted with the draft marine mammal report.

Reporting of Injured or Dead Marine Mammals

In the event that personnel involved in the construction activities discover an injured or dead marine mammal, the Navy shall report the incident to NMFS Office of Protected Resources (OPR) (*PR.ITP.MonitoringReports@noaa.gov*), NMFS (301-427-8401), and to the Greater Atlantic Region New England/Mid-Atlantic Stranding Coordinator (866-755-6622) as soon as feasible. The report must include the following information:

- Time, date, and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
- Species identification (if known) or description of the animal(s) involved;
- Condition of the animal(s) (including carcass condition if the animal is dead);
- Observed behaviors of the animal(s), if alive;
- If available, photographs or video footage of the animal(s); and
- General circumstances under which the animal was discovered.

If the death or injury was clearly caused by the specified activity, the Navy must immediately cease the specified activities until NMFS OPR is able to review the circumstances of the incident and determine what, if any, additional measures are appropriate to ensure compliance with the terms of this rule. The Navy shall not resume their activities until notified by NMFS that they can continue.

Negligible Impact Analysis and Determination

NMFS has defined negligible impact as an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival (50 CFR 216.103). A negligible impact finding is based on the lack of likely adverse effects on annual rates of recruitment or survival (*i.e.*, population-level effects). An estimate of the number of takes alone is not enough information on which to base an impact determination. In addition to considering estimates of the number of marine mammals that might be "taken" through harassment, NMFS considers other factors, such as the likely nature of any impacts or responses (*e.g.*, intensity, duration), the context of any impacts or responses (*e.g.*, critical reproductive time or location, foraging impacts affecting energetics), as well as effects on habitat, and the likely effectiveness of the mitigation. We also assess the number, intensity, and context of estimated takes by evaluating this information relative to population status. Consistent with the 1989 preamble for NMFS' implementing regulations (54 FR 40338, September 29, 1989), the impacts from other past and ongoing anthropogenic activities are incorporated into this analysis via their impacts on the baseline (*e.g.*, as reflected in the regulatory status of the species, population size and growth rate where known, ongoing sources of human-caused mortality, or ambient noise levels).

To avoid repetition, this introductory discussion of our analysis applies to all the species listed in Table 3, given that many of the anticipated effects of this project on different marine mammal stocks are expected to be relatively similar in nature. Where there are meaningful differences between species or stocks, or groups of species, in anticipated individual responses to activities, impact of expected take on the population due to differences in population status, or impacts on habitat, they are described independently in the analysis below.

Construction activities associated with the project, as outlined previously, have the potential to disturb or displace marine mammals. Specifically, the specified activities may result in take, in the form of Level A and Level B harassment from underwater sounds generated by pile driving activities, pile removal, and drilling. Potential takes could occur if marine mammals are

present in zones ensonified above the thresholds for Level A and Level B harassment, identified above, while activities are underway.

The Level A harassment zones identified in Tables 6 and 7 are based upon an animal exposed to pile driving or drilling multiple piles per day. Considering the short duration to impact drive each pile and breaks between pile installations (to reset equipment and move pile into place), an animal would have to remain within the area estimated to be ensonified above the Level A harassment threshold for multiple hours. This is highly unlikely given marine mammal movement throughout the area, especially for small, fast moving species such as small cetaceans and pinnipeds. Additionally, no Level A harassment is anticipated for humpback whales due to the required mitigation measures, which we expect the Navy will be able to effectively implement given the majority of the Level A harassment zones are small (under 300 m except for a few activities where additional PSOs will be utilized to cover the entirety of the Level A harassment zone), and high visibility of humpback whales. If an animal was exposed to sufficient accumulated sound energy to incur PTS, the resulting PTS would likely be small (*e.g.*, PTS onset) at lower frequencies where pile driving energy is concentrated, and unlikely to result in impacts to individual fitness, reproduction, or survival.

The nature of activities included in the Navy's pile driving project precludes the likelihood of serious injury or mortality. For all species and stocks, take will occur within a limited, confined area (immediately surrounding NAVSTA Norfolk in the Chesapeake Bay area) of the stock's range. Level A and Level B harassment will be reduced to the level of least practicable adverse impact through use of mitigation measures described herein. Furthermore, the amount of take authorized is extremely small when compared to stock abundance for all species aside from bottlenose dolphins, however take authorized for bottlenose dolphins is still expected to be small relative to the stock abundance as described in the Small Numbers section.

Effects on individuals that are taken by Level B harassment, on the basis of reports in the literature as well as monitoring from other similar activities, will likely be limited to reactions such as increased swimming speeds, increased surfacing time, or decreased foraging (if such activity were occurring) (*e.g.*, Thorson and Reyff, 2006). Individual animals, even if taken

multiple times, will most likely move away from the sound source and be temporarily displaced from the areas of pile driving or drilling, although even this reaction has been observed primarily only in association with impact pile driving. The pile driving and drilling activities analyzed here are similar to, or less impactful than, numerous other construction activities conducted along both Atlantic and Pacific coasts, which have taken place with no known long-term adverse consequences from behavioral harassment. Furthermore, many projects similar to this one are also believed to result in multiple takes of individual animals without any documented long-term adverse effects. Level B harassment will be minimized through use of mitigation measures described herein and, if sound produced by project activities is sufficiently disturbing, animals are likely to simply avoid the area while the activity is occurring, particularly as the project is located on a busy waterfront with high amounts of vessel traffic.

UMEs have been declared for Northeast pinnipeds (including harbor seal and gray seal) and Atlantic humpback whale. However, we do not expect authorized takes to exacerbate or compound upon these ongoing UMEs. As noted previously, no injury, serious injury, or mortality is expected or authorized, and Level B harassment takes of humpback whale, harbor seal and gray seal will be reduced to the level of least practicable adverse impact through the incorporation of the mitigation measures. For the WNA stock of gray seal, the estimated stock abundance is 27,300 (424,300 including estimates in Canadian waters). Given that only 1–2 takes by Level B harassment are authorized for this stock annually, we do not expect this authorization to exacerbate or compound upon the ongoing UME.

For the WNA stock of harbor seals, the estimated abundance is 61,336 individuals. The estimated M/SI (339) is well below the PBR (1,729). As such, the Level B harassment takes of harbor seal are not expected to exacerbate or compound upon the ongoing UMEs.

With regard to humpback whales, the UME does not yet provide cause for concern regarding population-level impacts. Despite the UME, the relevant population of humpback whales (the West Indies breeding population, or DPS) remains healthy.

Prior to 2016, humpback whales were listed under the ESA as an endangered species worldwide. Following a 2015 global status review (Bettridge *et al.*, 2015), NMFS established 14 DPSs with

different listing statuses (81 FR 62259, September 8, 2016) pursuant to the ESA. The West Indies DPS, which consists of the whales whose breeding range includes the Atlantic margin of the Antilles from Cuba to northern Venezuela, and whose feeding range primarily includes the Gulf of Maine, eastern Canada, and western Greenland, was delisted. The status review identified harmful algal blooms, vessel collisions, and fishing gear entanglements as relevant threats for this DPS, but noted that all other threats are considered likely to have no or minor impact on population size or the growth rate of this DPS (Bettridge *et al.*, 2015). As described in Bettridge *et al.*, (2015), the West Indies DPS has a substantial population size (*i.e.*, 12,312 (95 percent CI 8,688–15,954) whales in 2004–2005 (Bettridge *et al.*, 2003)), and appears to be experiencing consistent growth. NMFS has authorized no more than 8 takes by Level B harassment annually of humpback whale.

The project is also not expected to have significant adverse effects on affected marine mammals' habitats. The project activities will not modify existing marine mammal habitat for a significant amount of time. The activities may cause some fish to leave the area of disturbance, thus temporarily impacting marine mammals' foraging opportunities in a limited portion of the foraging range; but, because of the short duration of the activities and the relatively small area of the habitat that may be affected (with no known particular importance to marine mammals), the impacts to marine mammal habitat are not expected to cause significant or long-term negative consequences.

In summary and as described above, the following factors primarily support our determination that the impacts resulting from this activity are not expected to adversely affect any of the species or stocks through effects on annual rates of recruitment or survival:

- No mortality is anticipated or authorized;
- Authorized Level A harassment is of very small amounts and of low degree;
- The intensity of anticipated takes by Level B harassment is relatively low for all stocks;
- The number of anticipated takes is very low for humpback whale, harbor porpoise, and gray seal;
- The specified activity and associated ensouffled areas are very small relative to the overall habitat ranges of all species and do not include habitat areas of special significance;

- The lack of anticipated significant or long-term negative effects to marine habitat;

- The presumed efficacy of the mitigation measures in reducing the effects of the specified activity; and

- Monitoring reports from similar work in the Chesapeake Bay have documented little to no effect on individuals of the same species impacted by similar activities.

Based on the analysis contained herein of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the monitoring and mitigation measures, NMFS finds that the total marine mammal take from the activity will have a negligible impact on all affected marine mammal species or stocks.

Small Numbers

As noted previously, only small numbers of incidental take may be authorized under sections 101(a)(5)(A) and (D) of the MMPA for specified activities other than military readiness activities. The MMPA does not define small numbers and so, in practice, where estimated numbers are available, NMFS compares the number of individuals taken to the most appropriate estimation of abundance of the relevant species or stock in our determination of whether an authorization is limited to small numbers of marine mammals. When the predicted number of individuals to be taken is fewer than one-third of the species or stock abundance, the take is considered to be of small numbers. Additionally, other qualitative factors may be considered in the analysis, such as the temporal or spatial scale of the activities.

The maximum annual take of take NMFS authorized for the five marine mammal stocks is below one-third of the estimated stock abundance for all species except for the WNA southern coastal migratory stock and the WNA northern coastal migratory stock of bottlenose dolphins (see Table 12).

There are three bottlenose dolphin stocks that could occur in the project area. Therefore, largest estimated annual take by Level B harassment of 13,190 bottlenose dolphin would likely be split among the western WNA northern coastal migratory stock, the WNA southern coastal migratory stock, and the northern North Carolina Estuarine stock (NNCES). Based on the stocks' respective occurrence in the area, NMFS estimates that there would be no more than 200 takes from the NNCES stock, representing 24 percent of that population, with the remaining takes

split evenly between the northern and southern coastal migratory stocks. Based on the consideration of various factors as described below, we have determined that the number of individuals taken will comprise of less than one-third of the best available population abundance estimate of either coastal migratory stock. Detailed descriptions of the stocks' ranges have been provided in the Description of Marine Mammals in the Area of Specified Activities section of the proposed rule.

Both the northern migratory coastal and southern migratory coastal stocks have extensive ranges and they are the only dolphin stocks thought to make broad scale, seasonal migrations in coastal waters of the western North Atlantic. Given the large ranges associated with these two stocks, it is unlikely that large segments of either stock would approach the project area and enter into the Chesapeake Bay. The majority of both stocks are likely to be found widely dispersed across their respective habitat ranges and unlikely to be concentrated in or near the Chesapeake Bay.

Furthermore, the Chesapeake Bay and nearby offshore waters represent the boundaries of the ranges of each of the two coastal stocks during migration. The northern migratory coastal stock is found during warm water months from coastal Virginia, including the Chesapeake Bay and Long Island, New York. The stock migrates south in late summer and fall. During cold water months, dolphins may be found in coastal waters from Cape Lookout, North Carolina, to the North Carolina and Virginia border. During January–March, the southern migratory coastal stock appears to move as far south as northern Florida. From April–June, the stock moves back north to North Carolina. During the warm water months of July–August, the stock is presumed to occupy the coastal waters north of Cape Lookout, North Carolina, to Assateague, Virginia, including the Chesapeake Bay. There is likely some overlap between the northern southern migratory stocks during spring and fall migrations, but the extent of overlap is unknown.

The Chesapeake Bay and waters offshore of the mouth are located on the periphery of the migratory ranges of both coastal stocks (although during different seasons). Additionally, each of the migratory coastal stocks are likely to be located in the vicinity of the bay for relatively short timeframes. Given the limited number of animals from each migratory coastal stock likely to be found at the seasonal migratory boundaries of their respective ranges, in

combination with the short time periods (~2 months) animals might remain at these boundaries, it is reasonable to assume that takes are likely to occur only within some small portion of either of the migratory coastal stocks.

Many of the dolphin observations in the bay are likely repeated sightings of the same individuals. The Potomac-Chesapeake Dolphin Project has observed over 1,200 unique animals since observations began in 2015. Re-sightings of the same individual can be highly variable. Some dolphins are observed once per year, while others are highly regular with greater than 10 sightings per year (Mann, Personal Communication). Similarly, using available photo-identification data, Engelhaupt *et al.* (2016) determined that specified individuals were often observed in close proximity to their original sighting locations and were observed multiple times in the same season or same year. Ninety-one percent of re-sighted individuals (100 of 110) in the study area were recorded less than 30 km from the initial sighting location. Multiple sightings of the same individual would considerably reduce the number of individual animals that are taken by harassment. Furthermore, the existence of a resident dolphin population in the bay would increase the percentage of dolphin takes that are actually re-sightings of the same individuals.

In summary and as described above, the following factors primarily support our determination regarding the incidental take of small numbers of the affected stocks of a species or stock:

- The take of marine mammal stocks authorized comprises less than 3 percent of any stock abundance (with the exception of the three bottlenose dolphin stocks);
- Potential bottlenose dolphin takes in the project area are likely to be allocated among three distinct stocks;
- Bottlenose dolphin stocks in the project area have extensive ranges and it would be unlikely to find a high percentage of the individuals of any one stock concentrated in a relatively small area such as the project area or the Chesapeake Bay;
- The Chesapeake Bay represents the migratory boundary for each of the specified dolphin stocks and it would be unlikely to find a high percentage of any stock concentrated at such boundaries; and
- Many of the takes will likely be repeats of the same animals and likely from a resident population of the Chesapeake Bay.

Based on the analysis contained herein of the activity (including the

mitigation and monitoring measures) and the anticipated take of marine mammals, NMFS finds that small numbers of marine mammals will be taken relative to the population size of the affected species or stock.

Unmitigable Adverse Impact Analysis and Determination

There are no relevant subsistence uses of the affected marine mammal stocks or species implicated by this action. Therefore, NMFS has determined that the total taking of affected species or stocks will not have an unmitigable adverse impact on the availability of such species or stocks for taking for subsistence purposes.

Adaptive Management

The regulations governing the take of marine mammals incidental to Navy construction activities will contain an adaptive management component. The reporting requirements associated with this rule are designed to provide NMFS with monitoring data from completed projects to allow consideration of whether any changes are appropriate. The use of adaptive management allows NMFS to consider new information from different sources to determine (with input from the Navy regarding practicability) on an annual or biennial basis if mitigation or monitoring measures should be modified (including additions or deletions). Mitigation measures could be modified if new data suggests that such modifications would have a reasonable likelihood of reducing adverse effects to marine mammals and if the measures are practicable.

The following are some of the possible sources of applicable data to be considered through the adaptive management process: (1) results from monitoring reports, as required by MMPA authorizations; (2) results from general marine mammal and sound research; and (3) any information which reveals that marine mammals may have been taken in a manner, extent, or number not authorized by these regulations or subsequent LOAs.

National Environmental Policy Act

To comply with the National Environmental Policy Act of 1969 (NEPA; 42 U.S.C. 4321 *et seq.*) and NOAA Administrative Order (NAO) 216–6A, NMFS must review our proposed action (*i.e.*, the promulgation of regulations and subsequent issuance of incidental take authorization) with respect to potential impacts on the human environment.

This action is consistent with categories of activities identified in Categorical Exclusion B4 (IHAs with no

anticipated serious injury or mortality) of the Companion Manual for NOAA 216–6A, which do not individually or cumulatively have the potential for significant impacts on the quality of the human environment and for which we have not identified any extraordinary circumstances that would preclude this categorical exclusion. Accordingly, NMFS has determined that the action qualifies to be categorically excluded from further review under NEPA.

Endangered Species Act

Section 7(a)(2) of the Endangered Species Act of 1973 (ESA; 16 U.S.C. 1531 *et seq.*) requires that each Federal agency ensure that any action it authorizes, funds, or carries out 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. To ensure ESA compliance for the issuance of LOAs, NMFS consults internally whenever we propose to authorize take for endangered or threatened species.

No incidental take of ESA-listed species is authorized or expected to result from this activity. Therefore, NMFS has determined that formal consultation under section 7 of the ESA is not required for this action.

Classification

Pursuant to the procedures established to implement Executive Order 12866, the Office of Management and Budget has determined that this rule is not significant.

Pursuant to section 605(b) of the Regulatory Flexibility Act (RFA), the Chief Counsel for Regulation of the Department of Commerce has certified to the Chief Counsel for Advocacy of the Small Business Administration that this rule, if adopted, would not have significant economic impact on a substantial number of small entities. The Navy is the sole entity that would be subject to the requirements in these regulations, and the Navy is not a small governmental jurisdiction, small organization, or small business, as defined by the RFA. Therefore, a regulatory flexibility analysis is not required and none has been prepared.

This rule does not contain a collection-of-information requirement subject to the provisions of the Paperwork Reduction Act because the applicant is a Federal agency.

Waiver of Delay in Effective Date

The Assistant Administrator for Fisheries has determined that there is good cause under the Administrative Procedure Act (5 U.S.C. 553(d)(3)) to

waive the 30-day delay in the effective date of the measures contained in the final rule. The Navy is the only entity subject to these regulations, and it has informed NMFS that it requests that this final rule take effect as soon as possible. Any further delay in promulgating the final rule could result in a delay to the project schedule that would extend the completion of the project and cause further risks to the Virginia Class submarines schedule. In addition, in-water work at Pier 3 and associated fender systems are critical to timely completion of the overall project. Delaying the completion of ongoing work will have increased risk on other mission critical work, as some of the construction components cannot begin until others are started or in some cases completed. Moreover, the contractor is onsite and currently working under the existing IHA renewal (88 FR 20133, April 5, 2023). However, this renewal does not include all piles the Navy plans to install or remove within the first year of the rule in order to stay on schedule. Therefore, the Navy is ready to operate under the LOA immediately. For these reasons, the Assistant Administrator finds good cause to waive the 30-day delay in the effective date. In addition, the rule allows authorization of incidental take of marine mammals that would otherwise be prohibited under the statute. Therefore, the rule will relieve restrictions under the MMPA, which provides a separate basis under the Administrative Procedure Act (5 U.S.C. 553(d)(1)) to waive the 30-day delay in effective date.

List of Subjects in 50 CFR Part 217

Exports, Fish, Imports, Indians, Labeling, Marine mammals, Penalties, Reporting and recordkeeping requirements, Seafood, Transportation.

Dated: May 9, 2023.

Samuel D. Rauch, III,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For reasons set forth in the preamble, NMFS amends 50 CFR part 217 as follows:

PART 217—REGULATIONS GOVERNING THE TAKING AND IMPORTING OF MARINE MAMMALS

■ 1. The authority citation for part 217 continues to read as follows:

Authority: 16 U.S.C. 1361 *et seq.*, unless otherwise noted.

■ 2. Revise subpart L to read as follows:

Subpart L—Taking and Importing Marine Mammals Incidental to Navy Construction of the Pier 3 Replacement Project at Naval Station Norfolk at Norfolk, Virginia

Sec.

- 217.110 Specified activity and geographical region.
- 217.111 Effective dates.
- 217.112 Permissible methods of taking.
- 217.113 Prohibitions.
- 217.114 Mitigation requirements.
- 217.115 Requirements for monitoring and reporting.
- 217.116 Letters of Authorization.
- 217.117 Renewals and modifications of Letters of Authorization.
- 217.118 [Reserved]
- 217.119 [Reserved]

Subpart L—Taking and Importing Marine Mammals Incidental to U.S. Navy Construction of the Pier 3 Replacement Project at Naval Station Norfolk at Norfolk, Virginia

§ 217.110 Specified activity and geographical region.

(a) Regulations under this subpart apply only to the U.S. Navy (Navy) and those persons it authorizes or funds to conduct activities on its behalf for the taking of marine mammals that occurs in the areas outlined in paragraph (b) of this section and that occurs incidental to construction activities related to the replacement of Pier 3 at Naval Station Norfolk at Norfolk, Virginia.

(b) The taking of marine mammals by the Navy may be authorized in a Letter of Authorization (LOA) only if it occurs at Naval Station Norfolk, Norfolk, Virginia.

§ 217.111 Effective dates.

Regulations under this subpart are effective from May 18, 2023, through May 18, 2028.

§ 217.112 Permissible methods of taking.

Under an LOA issued pursuant to §§ 216.106 of this chapter and 217.116, the Holder of the LOA (hereinafter “Navy”) may incidentally, but not intentionally, take marine mammals within the area described in 217.110(b) by harassment associated with construction activities related to replacement of Pier 3, provided the activity is in compliance with all terms, conditions, and requirements of the regulations under this subpart and the applicable LOA.

§ 217.113 Prohibitions.

(a) Except for the takings contemplated in § 217.112 and authorized by a LOA issued under §§ 216.106 of this chapter and 217.116, it is unlawful for any person to do any of the following in connection with the activities described in § 217.110:

(1) Violate, or fail to comply with, the terms, conditions, and requirements of this subpart or a LOA issued under §§ 216.106 of this chapter and 217.116;

(2) Take any marine mammal not specified in such LOA;

(3) Take any marine mammal specified in such LOA in any manner other than as specified;

(4) Take a marine mammal specified in such LOA after NMFS determines such taking results in more than a negligible impact on the species or stocks of such marine mammal; or

(5) Take a marine mammal specified in such LOA after NMFS determined such taking results in an unmitigable adverse impact on the species or stock of such marine mammal for taking for subsistence uses.

(b) [Reserved]

§ 217.114 Mitigation requirements.

(a) When conducting the activities identified in § 217.110(a), the mitigation measures contained under this subpart and any LOA issued under §§ 216.106 of this chapter and 217.116 must be implemented by the Navy. These mitigation measures include:

(1) A copy of any issued LOA must be in the possession of the Navy, supervisory construction personnel, lead protected species observers (PSOs), and any other relevant designees of the Navy operating under the authority of the LOA at all times that activities subject to the LOA are being conducted.

(2) The Navy must ensure that construction supervisors and crews, the monitoring team, and relevant Navy staff are trained prior to the start of activities subject to any issued LOA, so that responsibilities, communication procedures, monitoring protocols, and operational procedures are clearly understood. New personnel joining during the project must be trained prior to commencing work.

(3) The Navy, construction supervisors and crews, and relevant Navy staff must avoid direct physical interaction with marine mammals during construction activity. If a marine mammal comes within 10 m of such activity, operations must cease and vessels must reduce speed to the minimum level required to maintain steerage and safe working conditions, as necessary to avoid direct physical interaction.

(4) The Navy must employ PSOs and establish monitoring locations as described in the NMFS-approved Marine Mammal Monitoring Plan. The Navy must monitor the project area to the maximum extent possible based on the required number of PSOs, required

monitoring locations, and environmental conditions.

(5) For all pile driving and drilling activity, the Navy shall implement shutdown zones with radial distances as identified in a LOA issued under § 217.116. If a marine mammal is observed entering or within the shutdown zone, such operations must be delayed or halted.

(6) Monitoring must take place from 30 minutes prior to initiation of pile driving or drilling activity (*i.e.*, pre-start clearance monitoring) through 30 minutes post-completion of pile driving or drilling activity.

(7) Pre-start clearance monitoring must be conducted during periods of visibility sufficient for the lead PSO to determine that the shutdown zones are clear of marine mammals. Pile driving and drilling may commence following 30 minutes of observation when the determination is made that the shutdown zones are clear of marine mammals.

(8) Should environmental conditions deteriorate such that marine mammals within the entire shutdown zone would not be visible (*e.g.*, fog, heavy rain, night), the Holder shall delay in-water construction activities until observers are confident marine mammals within the shutdown zone could be detected.

(9) If pile driving and/or drilling is delayed or halted due to the presence of a marine mammal, the activity may not commence or resume until either the animal has voluntarily exited and been visually confirmed beyond the shutdown zone or 15 minutes have passed without re-detection of the animal.

(10) Pile driving activity must be halted upon observation of either a species for which incidental take is not authorized or a species for which incidental take has been authorized but the authorized number of takes has been met, entering or within the harassment zone.

(11) The Navy must use soft start techniques when impact pile driving. Soft start requires contractors to provide an initial set of strikes at reduced energy, followed by a 30-second waiting period, then two subsequent reduced-energy strike sets. A soft start must be implemented at the start of each day's impact pile driving and at any time following cessation of impact pile driving for a period of 30 minutes or longer.

(b) [Reserved]

§ 217.115 Requirements for monitoring and reporting.

(a) The Navy shall submit a Marine Mammal Monitoring Plan to NMFS for

approval in advance of construction. Marine mammal monitoring must be conducted in accordance with the conditions in this section and the NMFS-approved Marine Mammal Monitoring Plan.

(b) Monitoring must be conducted by qualified, NMFS-approved PSOs, in accordance with the following conditions:

(1) PSOs must be independent of the activity contractor (for example, employed by a subcontractor) and have no other assigned tasks during monitoring periods.

(2) At least one PSO must have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization.

(3) Other PSOs may substitute other relevant experience, education (degree in biological science or related field), or training for prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization.

(4) One PSO must be designated as lead PSO or monitoring coordinator. The lead PSO must have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization.

(5) PSOs must be approved by NMFS prior to beginning any activity subject to any issued LOA.

(6) For all pile driving activities, a minimum of two PSOs shall be stationed at the best vantage points practicable to monitor for marine mammals and implement shutdown/delay procedures.

(7) For all pile driving activities, a minimum of two PSOs shall be stationed at the active pile driving site, docks, or piers to monitor the harassment and shutdown zones, and as described in the Marine Mammal Monitoring Plan. For shutdown zones exceeding 1,000 m, a minimum of three PSOs shall be stationed appropriately, as described in the Marine Mammal Monitoring Plan, to monitor the entire shutdown zone.

(8) The Navy shall monitor the harassment zones to the extent practicable and the entire shutdown zones. The Navy shall monitor at least a portion of the Level B harassment zone on all pile driving days.

(9) The Navy shall conduct hydroacoustic data collection in accordance with a Marine Mammal Monitoring Plan that must be approved by NMFS in advance of construction.

(10) The shutdown/monitoring zones may be modified with NMFS' approval

following NMFS' acceptance of an acoustic monitoring report.

(11) The Navy must submit a draft monitoring report to NMFS within 90 calendar days of the completion of each construction year. A draft comprehensive 5-year summary report must also be submitted to NMFS within 90 days of the end of the project. The reports must detail the monitoring protocol and summarize the data recorded during monitoring. Final annual reports and the final comprehensive report must be prepared and submitted within 30 days following resolution of any NMFS comments on the draft report. If no comments are received from NMFS within 30 days of receipt of the draft report, the report must be considered final. If comments are received, a final report addressing NMFS comments must be submitted within 30 days after receipt of comments. The reports must, at minimum, contain the informational elements described below (as well as any additional information described in the Marine Mammal Monitoring Plan), including:

(i) Dates and times (begin and end) of all marine mammal monitoring;

(ii) Construction activities occurring during each daily observation period, including the number and type of piles that were driven or removed and by what method (*i.e.*, impact, vibratory or drilling), total duration of driving time for each pile (vibratory and drilling) and number of strikes for each pile (impact);

(iii) PSO locations during marine mammal monitoring;

(iv) Environmental conditions during monitoring periods (at beginning and end of PSO shift and whenever conditions change significantly), including Beaufort sea state and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon, and estimated observable distance;

(v) Upon observation of a marine mammal, the follow information:

(A) Name of PSO who sighted the animal(s) and PSO location and activity at time of sighting;

(B) Time of sighting;

(C) Identification of the animal(s) (*e.g.*, genus/species, lowest possible taxonomic level, or unidentified), PSO confidence in identification, and the composition of the group if there is a mix of species;

(D) Distance and location of each observed marine mammal relative to the pile being driven for each sighting;

(E) Estimated number of animals (min/max/best estimate);

(F) Estimated number of animals by cohort (adults, juveniles, neonates, group composition, etc.); and

(G) Animal's closest point of approach and estimated time spent within the harassment zone.

(vi) Description of any marine mammal behavioral observations (*e.g.*, observed behaviors such as feeding or traveling), including an assessment of behavioral responses thought to have resulted from the activity (*e.g.*, no response or changes in behavioral state such as ceasing feeding, changing direction, flushing, or breaching);

(vii) Number of marine mammals detected within the harassment zones, by species; and

(viii) Detailed information about implementation of any mitigation (*e.g.*, shutdown and delays), a description of specific actions that ensued, and resulting changes in behavior of the animal(s), if any.

(12) The Holder must submit all PSO datasheets and/or raw sighting data within the draft report.

(13) All draft and final monitoring reports must be submitted to *PR.ITP.MonitoringReports@noaa.gov* and *ITP.corcoran@noaa.gov*.

(14) The Navy must report hydroacoustic data collected as required by a LOA issued under §§ 216.106 of this chapter and 217.116 and as discussed in the Navy's Marine Mammal Monitoring Plan approved by NMFS.

(15) In the event that personnel involved in the construction activities discover an injured or dead marine mammal, the Navy shall report the incident to the Office of Protected Resources, NMFS and to the Greater Atlantic Region New England/Mid-Atlantic Regional Stranding Coordinator as soon as feasible. If the death or injury was clearly caused by the specified activity, the Navy must immediately cease the specified activities until NMFS is able to review the circumstances of the incident and determine what, if any, additional measures are appropriate to ensure compliance with the terms of the authorization. The Navy must not resume their activities until notified by NMFS. The report must include the following information:

(i) Time, date, and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);

(ii) Species identification (if known) or description of the animal(s) involved;

(iii) Condition of the animal(s) (including carcass condition if the animal is dead);

(iv) Observed behaviors of the animal(s), if alive;

(v) If available, photographs or video footage of the animal(s); and

(vi) General circumstances under which the animal was discovered.

§ 217.116 Letters of Authorization.

(a) To incidentally take marine mammals pursuant to the regulations under this subpart, the Navy must apply for and obtain an LOA.

(b) An LOA, unless suspended or revoked, may be effective for a period of time not to exceed the expiration date of the regulations under this subpart.

(c) If an LOA expires prior to the expiration date of the regulations under this subpart, the Navy may apply for and obtain a renewal of the LOA.

(d) In the event of projected changes to the activity or to mitigation and monitoring measures required by an LOA, the Navy must apply for and obtain a modification of the LOA as described in § 217.116.

(e) The LOA must set forth the following information:

(1) Permissible methods of incidental taking;

(2) Means of effecting the least practicable adverse impact (*i.e.*, mitigation) on the species, its habitat, and on the availability of the species for subsistence uses; and

(3) Requirements for monitoring and reporting.

(f) Issuance of the LOA must be based on a determination that the level of taking must be consistent with the findings made for the total taking allowable under the regulations under this subpart.

(g) Notice of issuance or denial of an LOA must be published in the **Federal Register** within 30 days of a determination.

§ 217.117 Renewals and modifications of Letters of Authorization.

(a) An LOA issued under §§ 216.106 of this chapter and 217.116 for the activity identified in § 217.110(a) may be renewed or modified upon request by the applicant, provided that:

(1) The specified activity and mitigation, monitoring, and reporting measures, as well as the anticipated impacts, are the same as those described and analyzed for the regulations under this subpart; and

(2) NMFS determines that the mitigation, monitoring, and reporting measures required by the previous LOA under the regulations under this subpart were implemented.

(b) For LOA modification or renewal requests by the applicant that include changes to the activity or the mitigation,

monitoring, or reporting that do not change the findings made for the regulations or result in no more than a minor change in the total estimated number of takes (or distribution by species or years), NMFS may publish a notice of proposed LOA in the **Federal Register**, including the associated analysis of the change, and solicit public comment before issuing the LOA.

(c) A LOA issued under §§ 216.106 of this chapter and 217.116 for the activity identified in § 217.110(a) may be modified by NMFS under the following circumstances:

(1) NMFS may modify (including augment) the existing mitigation, monitoring, or reporting measures (after consulting with Navy regarding the practicability of the modifications) if

doing so creates a reasonable likelihood of more effectively accomplishing the goals of the mitigation and monitoring for the regulations under this subpart;

(i) Possible sources of data that could contribute to the decision to modify the mitigation, monitoring, or reporting measures in a LOA:

(A) Results from Navy's monitoring from previous years;

(B) Results from other marine mammal and/or sound research or studies; and

(C) Any information that reveals marine mammals may have been taken in a manner, extent or number not authorized by the regulations under this subpart or subsequent LOAs; and

(ii) If, through adaptive management, the modifications to the mitigation,

monitoring, or reporting measures are substantial, NMFS must publish a notice of proposed LOA in the **Federal Register** and solicit public comment;

(2) If NMFS determines that an emergency exists that poses a significant risk to the well-being of the species or stocks of marine mammals specified in a LOA issued pursuant to §§ 216.106 of this chapter and 217.116, a LOA may be modified without prior notice or opportunity for public comment. Notification would be published in the **Federal Register** within 30 days of the action.

§§ 217.118–217.119 [Reserved]

[FR Doc. 2023–10168 Filed 5–17–23; 8:45 am]

BILLING CODE 3510–22–P

Proposed Rules

Federal Register

Vol. 88, No. 96

Thursday, May 18, 2023

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA-2023-1186; Airspace
Docket No. 23-ASO-22]

RIN 2120-AA66

Amendment of Class E Airspace; Cedartown, GA

AGENCY: Federal Aviation
Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking
(NPRM).

SUMMARY: This action proposes to amend Class E airspace extending upward from 700 feet above the surface for Polk County Airport/Cornelius Moore Field, Cedartown, Georgia, has been designed as a new instrument approach procedure for this airport. This action would also update this airport's name and geographic coordinates to coincide with the FAA's database.

DATES: Comments must be received on or before July 3, 2023.

ADDRESSES: Send comments identified by FAA Docket No. FAA-2023-1186 and Airspace Docket No. 23-ASO-22 using any of the following methods:

* *Federal eRulemaking Portal:* Go to www.regulations.gov and follow the online instructions for sending your comments electronically.

* *Mail:* Send comments to Docket Operations, M-30; U.S. Department of Transportation, 1200 New Jersey Avenue SE, Room W12-140, West Building Ground Floor, Washington, DC 20590-0001.

* *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12-140 of the West Building Ground Floor at 1200 New Jersey Avenue SE, Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except for Federal holidays.

* *Fax:* Fax comments to Docket Operations at (202) 493-2251.

Docket: Background documents or comments received may be read at www.regulations.gov anytime. Follow the online instructions for accessing the docket or go to the Docket Operations in Room W12-140 of the West Building Ground Floor at 1200 New Jersey Avenue SE, Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except for Federal holidays.

FAA Order JO 7400.11G Airspace Designations and Reporting Points and subsequent amendments can be viewed online at www.faa.gov/air_traffic/publications/. You may also contact the Rules and Regulations Group, Office of Policy, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267-8783.

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, 1701 Columbia Avenue, College Park, GA 30337; Telephone: (404) 305-6364.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the United States Code. 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. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority, as it would amend Class E airspace in Cedartown, Georgia. This action is necessary to support IFR operations in the area.

Comments Invited

The FAA invites interested persons to participate in this rulemaking by submitting written comments, data, or views. Comments are specifically invited on the proposal's overall regulatory, aeronautical, economic, environmental, and energy-related aspects. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include

supporting data. To ensure the docket does not contain duplicate comments, commenters should submit only once if comments are filed electronically, or commenters should send only one copy of written comments if comments are filed in writing.

The FAA will file in the docket all comments it receives and a report summarizing each substantive public contact with FAA personnel concerning this proposed rulemaking. Before acting on this proposal, the FAA will consider all comments it receives on or before the closing date for comments. The FAA will consider comments filed after the comment period has closed if it is possible to do so without incurring expense or delay. The FAA may change this proposal in light of the comments it receives.

Privacy: In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to www.regulations.gov, as described in the system of records notice (DOT/ALL-14 FDMS), which can be reviewed at www.dot.gov/privacy.

Availability of NPRMs

An electronic copy of this document may be downloaded online at www.regulations.gov. Recently published rulemaking documents can be accessed through the FAA's web page at www.faa.gov/air_traffic/publications/airspace_amendments/.

You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9:00 a.m. and 5:00 p.m., Monday through Friday, except for Federal holidays. An informal docket may also be examined between 8:00 a.m. and 4:30 p.m., Monday through Friday, except on Federal holidays at the office of the Eastern Service Center, Federal Aviation Administration, Room 350, 1701 Columbia Avenue, College Park, GA 30337.

Incorporation by Reference

Class E airspace designations are published in Paragraph 6005 of FAA Order JO 7400.11, Airspace Designations and Reporting Points, incorporated by reference in 14 CFR

71.1 annually. This document proposes to amend the current version of that order, FAA Order JO 7400.11G, Airspace Designations and Reporting Points, dated August 19, 2022, and effective September 15, 2022. These updates would subsequently be published in the next update to FAA Order JO 7400.11. FAA Order JO 7400.11G is publicly available as listed in the **ADDRESSES** section of this document. FAA Order JO 7400.11G lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

The Proposal

The FAA proposes an amendment to 14 CFR part 71 to amend Class E airspace extending upward from 700 feet above the surface for Polk County Airport/Cornelius Moore Field (new name), Cedartown, Georgia, to accommodate area navigation (RNAV) global positioning system (GPS) standard instrument approach procedures (SIAPs) serving this airport. This amendment supports a new instrument approach at this airport. The existing radius would remain, and an extension would be created to the north of the airport. This action would also update the airport's name (formerly Cornelius-Moore Field Airport) and geographic coordinates to coincide with FAA's database. Controlled airspace is necessary for the area's safety and management of instrument flight rules (IFR) operations.

Regulatory Notices and Analyses

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore: (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under Department of Transportation (DOT) Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this proposed rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1F,

"Environmental Impacts: Policies and Procedures," prior to any FAA final regulatory action.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

- 1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

- 2. The incorporation by reference in 14 CFR 71.1 of FAA Order JO 7400.11G, Airspace Designations and Reporting Points, dated August 19, 2022, and effective September 15, 2022, is amended as follows:

Paragraph 6005 Class E Airspace Areas Extending Upward From 700 Feet or More Above the Surface of the Earth.

* * * * *

ASO FL E5 Cedartown, GA [Amended]

Polk County Airport/Cornelius Moore Field, GA
(Lat 34°01'07" N, long. 85°08'41" W)

That airspace extending upward from 700 feet above the surface within a 7.7-mile radius of Polk County Airport/Cornelius Moore Field and within 1.1 miles on each side of the 008° bearing of the airport, extending from the 7.7-mile radius to 8.7 miles north of the airport.

* * * * *

Issued in College Park, Georgia, on May 12, 2023.

Andree C. Davis,

Manager, Airspace & Procedures Team South, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2023–10494 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF EDUCATION

34 CFR Part 300

[Docket ID ED–2022–OSERS–0052]

RIN 1820–AB82

Assistance to States for the Education of Children With Disabilities

AGENCY: Office of Special Education and Rehabilitative Services, Department of Education.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Secretary proposes to amend regulations under Part B of the Individuals with Disabilities Education Act (Part B of IDEA or the Act) that govern the Assistance to States for the Education of Children with Disabilities program, including the Preschool Grants program. Specifically, the Secretary proposes to amend the IDEA Part B regulations to remove the requirement for public agencies to obtain parental consent prior to accessing for the first time a child's public benefits or insurance (e.g., Medicaid, Children's Health Insurance Program (CHIP)) to provide or pay for required IDEA Part B services. As there are no comparable consent requirements prior to accessing public benefits for children without disabilities, the removal of this consent requirement would align public benefits consent requirements for children with disabilities to those for children without disabilities and ensure equal treatment of both groups of children.

DATES: We must receive your comments on or before August 1, 2023.

ADDRESSES: Comments must be submitted via the Federal eRulemaking Portal at [regulations.gov](https://www.regulations.gov). However, if you require an accommodation or cannot otherwise submit your comments via [regulations.gov](https://www.regulations.gov), please contact the program contact person listed under **FOR FURTHER INFORMATION CONTACT**. The Department will not accept comments by fax or by email, or comments submitted after the comment period closes. To ensure that the Department does not receive duplicate copies, please submit your comments only once. Additionally, please include the Docket ID at the top of your comments.

Federal eRulemaking Portal: Please go to www.regulations.gov to submit your comments electronically. Information on using [Regulations.gov](https://www.regulations.gov), including instructions for finding a rule on the site and submitting comments, is available on the site under "FAQ."

Note: The Department's policy is to generally make comments received from members of the public available for

public viewing at www.regulations.gov. Therefore, commenters should include in their comments only information about themselves that they wish to make publicly available.

FOR FURTHER INFORMATION CONTACT:

Rebecca Walawender, U.S. Department of Education, 400 Maryland Ave. SW, Room 5130, Potomac Center Plaza, Washington, DC 20202. Telephone: (202) 245-7399. Email: Rebecca.Walawender@ed.gov.

If you are deaf, hard of hearing, or have a speech disability and wish to access telecommunications relay services, please dial 7-1-1.

SUPPLEMENTARY INFORMATION:

Invitation to Comment: We invite you to submit comments regarding this proposed regulation. To ensure that your comments have maximum effect in developing the final regulation, we urge you to clearly identify the specific section or sections of the proposed regulation that each of your comments addresses.

Directed Questions: As currently drafted, the proposed regulatory language would retain the requirement to include in the written notification to parents the “no cost” provisions in 34 CFR 300.154(d)(2)(i) through (iii). We invite your comments on the following questions relating to the written notification related to the “no cost” provisions in § 300.154(d)(2)(i) through (iii),¹ which will continue to remain in effect and would not be changed by this proposed regulatory action:

1. Should the “no cost” provisions in § 300.154(d)(2)(i) through (iii) continue to be included in the written notification to parents prior to accessing the child’s public benefits or insurance for the first time and annually thereafter?

2. Should the “no cost” provisions in § 300.154(d)(2)(i) through (iii) be included in the written notification to parents prior to accessing the child’s public benefits or insurance for the first time, but removed in annual written notifications thereafter?

3. Should the “no cost” provisions in § 300.154(d)(2)(i) through (iii) be removed from the written notification to parents altogether?

We invite you to assist us in complying with the specific requirements of Executive Orders 12866

and 13563 and their overall requirement of reducing regulatory burden that might result from this proposed regulation. Please let us know of any further ways we could reduce potential costs or increase potential benefits while preserving the effective and efficient administration of the Department’s programs and activities. The Department also welcomes comments on any alternative approaches to the subjects addressed in the proposed regulation.

During and after the comment period, you may inspect public comments about this proposed regulation by accessing *Regulations.gov*.

Assistance to Individuals with Disabilities in Reviewing the Rulemaking Record: On request, we will provide an appropriate accommodation or auxiliary aid to an individual with a disability who needs assistance to review the comments or other documents in the public rulemaking record for the proposed regulation. To schedule an appointment for this type of accommodation or auxiliary aid, please contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

Background

Prior Actions

Since IDEA’s reauthorization in 2004, the Department has on multiple occasions examined the administrative steps that must be taken when a public agency seeks to access a child’s or parent’s public benefits or insurance (such as Medicaid) to pay for services required under IDEA Part B for children with disabilities. In 2006, the Department enacted IDEA Part B regulations that required a public agency to obtain parental consent each time the agency seeks access to a child’s or parent’s public benefits or insurance. 34 CFR 300.154(d)(2)(iv). See 71 FR 46539, 46772 (Aug. 14, 2006). This regulatory provision was further clarified through nonregulatory guidance. Because the regulation appeared to require consent every time a service was provided (if, for example, a child’s individualized education program (IEP) included a service covered by public insurance that was provided multiple times each week, then consent would be required each time the service was delivered), in 2007 the Department advised that a public agency alternatively could obtain parental consent under § 300.154 for a specific time period (e.g., annual consent). Office of Special Education

Programs (OSEP) Memo 07-10.² Further, the Department noted that consent was required under § 300.154 if the public agency sought to use such benefits for additional hours of service (if, for example, the IEP was revised or extended) or sought to charge different amounts for the services. OSEP Memo 07-10.

In 2013, the Department revised § 300.154 to its current form. 78 FR 10525 (Feb. 14, 2013). As currently written, the provision requires a one-time initial parental consent after the public agency has given written notification of its intent to access the child’s or parent’s public benefits or insurance, and annual written notification thereafter. 34 CFR 300.154(d)(2)(iv) and (v). Such consent is to permit the use of public benefits or insurance to seek the appropriate reimbursement for the appropriate service. Id. The consent requirement in 34 CFR 300.154(d)(2) is separate from, and in addition to, the parental consent requirements under both Part B of the IDEA (34 CFR 300.622) and the Family Educational Rights and Privacy Act (FERPA) (20 U.S.C. 1232g and 34 CFR 99.30), which require the participating agency (usually the local educational agency (LEA)) to obtain parent consent to disclose personally identifiable information (PII) to a public benefits or public insurance agency for billing purposes. This consent requirement is separate from and does not change the parental consent required for the initial evaluation to determine whether a child is a child with a disability under IDEA (34 CFR 300.300(a)), consent for the initial provision of special education and related services under IDEA (34 CFR 300.300(b)), consent for the reevaluation of a child with a disability (34 CFR 300.300(c)), or consent to disclose PII to a State entity for Medicaid billing under either FERPA (34 CFR part 99) or IDEA (34 CFR 300.622).

In the 2013 rulemaking, several commenters asked the Department to remove the consent process to reduce administrative burden and increase access to Medicaid reimbursement for services required under IDEA. At that time, the Department acknowledged the importance of reducing funding barriers and streamlining consent requirements specific to IDEA Part B, and ultimately added both the initial consent requirement (removing the requirement that consent be obtained each time access to public benefits or insurance is

¹ IDEA requires that special education, related services and supplementary aids and services are provided at no-cost to a child or their family. IDEA calls this a Free Appropriate Public Education in § 300.17. The no cost provisions in 300.154(d)(2)(ii) through (iii) are unallowable examples where accessing public benefits would incur costs to the family, including co-pays, deductibles, and increased premiums.

² <https://sites.ed.gov/idea/files/idea/policy/speced/guid/idea/memosdcltrs/osep07-10interpretationof34cfr300154.pdf>.

sought) and the parental notification requirement in § 300.154(d). Based on the Department's oversight and administration of IDEA since that time as well as continued stakeholder concerns regarding the barriers this requirement imposes on accessing public benefits and insurance,³ and for the reasons described below, the Secretary no longer believes the initial consent requirement in § 300.154 is necessary, given the existing regulatory protections in IDEA Part B and FERPA that protect the privacy rights of parents and students as well as the "no-cost" protections in the notification provisions in § 300.154. The Secretary thus proposes to rescind the Department's current requirements in § 300.154(d)(2)(iv) and revise the requirements in current § 300.154(d)(2)(v).

Administration's Policy Priorities

The Biden-Harris Administration has established a clear policy goal to increase access to health and mental health services. The Administration's mental health strategy is focused on three elements: strengthening system capacity, connecting people to care, and creating a continuum of support.⁴ Increasing access to needed health and mental health services that can be delivered to students at school is a key element of this policy goal.

Consistent with section 11003 of the Bipartisan Safer Communities Act and Executive Orders 14009, Strengthening Medicaid and the Affordable Care Act and 14070 Continuing to Strengthen Americans' Access to Affordable, Quality Health Coverage, the Biden-Harris Administration is committed to strengthening and increasing access to school-based health services. Section 11003 of the Bipartisan Safer Communities Act requires the Department, along with the U.S. Department of Health and Human Services, to collaborate to eliminate barriers to the delivery of Medicaid

services to enrolled children. Public Law 117–159. To this end, the Departments are jointly developing policies that will increase access to school-based health services for children who are enrolled in Medicaid.

Now, more than ever, ensuring access to school-based Medicaid services for children with disabilities is essential. Recent research from the Substance Abuse and Mental Health Services Agency (SAMHSA) shows that individuals of low-socioeconomic status are more vulnerable during and after a disaster (e.g., pandemics or catastrophic weather events), including by living in fragile housing, having difficulty accessing resources after a disaster, and experiencing trauma both during and after a disaster.⁵ Our Nation's youth generally are experiencing unprecedented mental health challenges. As described in the Biden-Harris Administration's mental health strategy, "Our youth have been particularly impacted as losses from COVID and disruptions in routines and relationships have led to increased social isolation, anxiety, and learning loss. More than half of parents express concern over their children's mental well-being."⁶

Children with disabilities are disproportionately and significantly more affected by these challenges. Data in the Department's report on *Supporting Child and Student Social, Emotional, Behavioral and Mental Health Needs*⁷ indicate that, compared to students without disabilities, children and students with disabilities experience higher rates of mental health challenges, including anxiety, depression, academic-related stress, suicidal ideation, suicide attempts, non-suicidal self-injury, and peer victimization. Fragmented delivery systems and policy and funding gaps make this mental health crisis more challenging to address. Id. The report recommends establishing an integrated

framework of educational, social, emotional, and behavioral health support for all and to leverage policy and funding.

Medicaid Funding in Schools

Medicaid is one of our Nation's primary sources of funding for health and mental health services for children with and without disabilities, covering approximately 41.6 million children and 42 percent of all childbirths,⁸ and funding health and mental health services in schools. Under Medicaid's Early Periodic Screening Diagnosis and Treatment benefit, eligible children can receive comprehensive primary health, mental health and behavioral health services.⁹ In 2014 guidance to State Medicaid Directors (SMDs), the Centers for Medicare & Medicaid Services (CMS) clarified that Medicaid payment is permitted for any covered services provided to Medicaid-eligible beneficiaries as long as they are delivered by Medicaid-qualified providers.¹⁰ That guidance was intended to facilitate access to quality healthcare services within school settings and improve the health of communities, and ensure that Medicaid reimbursement is available for covered services that are provided to Medicaid beneficiaries, regardless of whether there is any charge for the service to the beneficiary or the community at large.¹¹

Many children with disabilities receiving services under IDEA are also enrolled in Medicaid due to their disability status and/or based on their family income. Children with disabilities and special health care needs are more likely to be low-income, and those covered by Medicaid are more likely to have greater health care needs than those who are covered by private insurance.¹² Further, the COVID–19

³ See Obtaining Parental Consent to Bill Medicaid: An Unnecessary, Time-Consuming and Emotionally Fraught Process for Districts and Parents, a report jointly issued by the School Superintendents Association, the Association of Educational Services Agencies and the National Alliance for Medicaid in Education. https://www.aasa.org/docs/default-source/advocacy/medicaid-parental-consent-2023.pdf?sfvrsn=f8d706b2_3.

⁴ See The White House, "Fact Sheet: President Biden to Announce Strategy to Address Our National Mental Health Crisis, as Part of Unity Agenda In His First State of The Union" (Mar. 1, 2022). <https://www.whitehouse.gov/briefing-room/statements-releases/2022/03/01/fact-sheet-president-biden-to-announce-strategy-to-address-our-national-mental-health-crisis-as-part-of-unity-agenda-in-his-first-state-of-the-union/>.

⁵ Substance Abuse and Mental Health Services Agency, Disaster Technical Assistance Center Supplemental Research Bulletin, "Greater Impact: How Disasters Affect People of Low Socioeconomic Status" (July 2017). Available at: https://www.samhsa.gov/sites/default/files/dtac/srb-low-ses_2.pdf.

⁶ Id. The Unity Agenda also noted that, "[i]n 2019, one in three high school students and half of female students reported persistent feelings of sadness or hopelessness, an overall increase of 40 percent from 2009. Emergency department visits for attempted suicide have risen 51 percent among adolescent girls."

⁷ U.S. Department of Education, Office of Special Education and Rehabilitative Services, "Supporting Child and Student Social, Emotional, Behavioral, and Mental Health Needs," (2021). Available at: <https://www2.ed.gov/documents/students/supporting-child-student-social-emotional-behavioral-mental-health.pdf>.

⁸ See December 2022 Medicaid & CHIP Enrollment Data Highlights <https://www.medicaid.gov/medicaid/program-information/medicaid-and-chip-enrollment-data/report-highlights/index.html#:~:text=92%2C340%2C585%20individuals%20were%20enrolled%20in,individuals%20were%20enrolled%20in%20CHIP> and National Vital Statistics Reports Volume 70, Number 2, March 23 Births: Final Data for 2019 (cdc.gov).

⁹ <https://www.medicaid.gov/federal-policy-guidance/downloads/sbscib081820222.pdf>.

¹⁰ SMD# 14–006. Available at: <https://www.medicaid.gov/federal-policy-guidance/downloads/smd-medicaid-payment-for-services-provided-without-charge-free-care.pdf>.

¹¹ SMD# 14–006. Available at: <https://www.medicaid.gov/federal-policy-guidance/downloads/smd-medicaid-payment-for-services-provided-without-charge-free-care.pdf>.

¹² Williams, Elizabeth & Musumeci, MaryBeth (2021). "Children with Special Health Care Needs: Coverage, Affordability, and HCBS Access." Kaiser Family Foundation. Available at: <https://>

pandemic has limited access to critical services for children with disabilities and other vulnerable populations.¹³ To meet the Administration's goal of increasing access to health and mental health services, it is imperative to specifically address barriers to accessing funding and Medicaid services for low-income children with disabilities.

IDEA requires public agencies to make a free appropriate public education (FAPE) available to all eligible children with disabilities, which means, among other things, that the services identified on a child's IEP must be provided at public expense and without charge to the child or the child's parents. A public agency may access a child's or parent's public benefits or insurance to pay for IDEA Part B services, but this requires the agency to share PII about the child in question with the agency or entity managing the benefits. IDEA contemplates that public agencies should, in appropriate circumstances, access public benefits and insurance programs to help pay for services required under Part B, while reaffirming the requirement that such services be delivered at no cost to parents.

Equal Treatment of Children With and Without Disabilities

Medicaid regulations do not require Medicaid agencies or providers (such as schools) to obtain consent from the beneficiary or family member prior to exchanging the individual's information for a purpose directly connected to the administration of the Medicaid State plan, which includes billing Medicaid for providing services to the beneficiaries. 42 CFR 431.306. Instead, the act of enrolling a child or parent in Medicaid serves as consent for Medicaid providers to access public benefits for billing purposes. For children with disabilities, however, regardless of Medicaid, FERPA (34 CFR 99.30) and IDEA (34 CFR 300.622) require parental consent before disclosing PII, and the transfer of PII is often a necessary step in billing Medicaid. In addition, for Medicaid-eligible children with disabilities, current IDEA requirements

in § 300.154(d)(2)(iv) and (v) require schools to secure parental consent to bill Medicaid before seeking reimbursement for services identified on a child's IEP. This last regulatory requirement does not exist to access Medicaid for services provided to Medicaid-eligible children without disabilities. Rescinding 34 CFR 300.154(d)(2)(iv) and revising 34 CFR 300.154(d)(2)(v), while maintaining existing PII disclosure protections in FERPA (34 CFR 99.30) and IDEA (34 CFR 300.622), would ensure equal treatment of Medicaid beneficiaries, reduce administrative burden, and eliminate a barrier to reimbursement.

Reimbursement of health care costs through school-based Medicaid claims can be an important source of financial support for public agencies providing school-based services. According to the Medicaid Financial Management Report, in FY 2021,¹⁴ \$4,280,950,805 was expended for school-based services and funded through Medicaid's Medical Assistance Program, and an additional \$1,699,326,212 in school-based administration costs were reimbursed through Medicaid. By increasing the ability of public agencies to bill Medicaid for school-based services, this proposed change would increase the overall level of financial support for public agencies, and would increase the funding available to State and local educational agencies to provide important services and supports to students under the IDEA.

Section 300.154. *Methods of Ensuring Services Statute*: 20 U.S.C. 1412(a)(12) requires, as a condition of eligibility for an IDEA Part B grant award, each State to provide assurances that it has a statute, regulation, an interagency agreement or other appropriate written mechanism for interagency coordination that is in effect to identify the financial responsibility of non-educational public agencies for providing services required to ensure FAPE to children with disabilities, and that the financial responsibility of those agencies, including the State Medicaid agency and other public insurers of children with disabilities, precedes the financial responsibility of the LEA or the State agency responsible for developing the child's IEP. This requirement is consistent with IDEA's payor of last resort requirements in IDEA sections 612(e) and 640(c) and section 1903(c) of the Medicaid statute, which state that as between Federal IDEA funds and

Medicaid, Medicaid is the payor of first resort.

Current Regulations: Section 300.154(d)(2)(iv) requires a public agency to obtain a one-time consent from the parent, after providing written notification, before accessing the child's or the parent's public benefits or insurance for the first time. This consent must specify PII that may be disclosed, the purpose of the disclosure, and the agency to which the disclosure may be made. See §§ 99.30 and 300.622. The consent also must specify that the parent understands and agrees that the public agency may access the child's or parent's public benefits or insurance to pay for IDEA Part B services.

Section 300.154(d)(2)(v) requires that the written notification to the child's parents be consistent with § 300.503(c)—that is, be in a language understandable to the general public, and in the native language of the parent or other mode of communication used by the parent (unless it is clearly not feasible to do so). The notification must be provided before accessing the child's or the parent's public benefits or insurance for the first time, prior to obtaining the one-time parental consent, and annually thereafter. The written notification must include: (1) a statement of the parental consent provisions in § 300.154(d)(2)(iv)(A) and (B); (2) a statement of the "no cost" provisions under § 300.154(d)(2)(i) through (iii) informing the parent that the agency may not require parents to enroll in Medicaid, may not require parents to incur an out-of-pocket expense incurred in filing a claim for services, and may not use a child's Medicaid benefits if that use would decrease lifetime coverage or any other insured benefit, result in the family paying for services that would otherwise be covered by Medicaid and that are required for the child outside of the time the child is in school, increase premiums or lead to discontinuation of benefits or insurance, or risk loss of eligibility for home and community-based waivers; (3) a statement that the parents have the right to withdraw consent to disclosure of their child's PII to the agency responsible for the administration of the State's public benefits or insurance program at any time; and (4) a statement that refusal to provide consent or withdrawal of consent to disclose PII to the agency responsible for the administration of the State's public benefits or insurance program does not relieve the public agency of its responsibility to ensure that all required services are provided at no cost to the parents.

www.kff.org/medicaid/issue-brief/children-with-special-health-care-needs-coverage-affordability-and-hcbs-access/.

¹³ U.S. Department of Education, Office of Special Education and Rehabilitative Services, "Supporting Child and Student Social, Emotional, Behavioral, and Mental Health Needs," (2021). Available at: <https://www2.ed.gov/documents/students/supporting-child-student-social-emotional-behavioral-mental-health.pdf>. See also: U.S. Department of Education, Office for Civil Rights, "Education in a Pandemic: The Disparate Impacts of COVID-19 on America's Students," (2021). Available at: <https://www2.ed.gov/about/offices/list/ocr/docs/20210608-impacts-of-covid19.pdf>.

¹⁴ <https://www.medicaid.gov/medicaid/financial-management/downloads/financial-management-report-fy2021.zip>.

Proposed Regulations: We propose to rescind current § 300.154(d)(2)(iv), which would remove the requirement for parental consent prior to accessing a child's or parent's public benefits or insurance for the first time.

We propose to revise the current parental notification requirements in § 300.154(d)(2)(v). The revised provision would continue to state that the required parental notification must be consistent with § 300.503(c), and it would still include a statement of the "no cost" provisions in current § 300.154(d)(2)(i) through (iii). The proposed revision of § 300.154(d)(2)(v) would modify the reference to parental consent, to confirm that parental consent to disclose PII is required separately under §§ 99.30 and 300.622 and that parents retain all applicable privacy rights under those provisions. Section 300.154(d)(2)(v) would be further revised to no longer require the following two statements: a statement that the parents have the right to withdraw consent to disclose their child's PII to the agency responsible for the administration of the State's public benefits or insurance program at any time; and a statement that refusal to provide consent or withdrawal of consent to disclose PII to the agency responsible for the administration of the State's public benefits or insurance program does not relieve the public agency of its responsibility to ensure that all required services are provided at no cost to the parents. It is important to note that nothing in this proposed regulation will change or diminish parents' rights to consent to an evaluation under IDEA or the initial provision of special education and related services under IDEA.

Reasons: In light of the challenges described in the "Background" section, and consistent with the Administration's priorities, the Secretary believes that the Department should eliminate regulatory provisions that present unnecessary barriers to public agencies seeking Medicaid reimbursement for school-based Medicaid services provided to children receiving special education and related services under IDEA Part B, particularly where such barriers do not exist for similarly situated children without disabilities. The one-time consent provision in § 300.154(d)(2)(iv) represents such a barrier. As discussed further below, that provision slows down or may prevent public agencies from accessing available funding for needed IDEA services without providing any additional protection to families.

Federal regulations do not prohibit public agencies from accessing a child's

or parent's public benefits or insurance to pay for special education and related services if such use would not result in additional costs to the parent or reduce benefits to the child. To maximize public agencies' access to Federal Medicaid funds, the proposed regulations would no longer require the public agency to obtain parental consent prior to accessing a child's or parent's public benefits or insurance for the first time, other than the consent to release PII that already is required consistent with part 99 and § 300.622. Public agencies would continue to be required to provide written notification to parents prior to accessing a child's or parent's public benefits or insurance for the first time and annually thereafter. The timing of the written notification to the parent would continue to be at the agency's discretion, so long as the first such written notification is given *before* the public agency seeks access to the child's or parent's public benefits or insurance for the first time.

These changes would align Medicaid billing for children with and without disabilities, while retaining important protections for children and families. The privacy rights of children with disabilities remain important to the Department, and, as noted above, the Department would retain written consent protections under FERPA and the IDEA Part B regulations that require a public agency to obtain written consent before disclosing PII from a child's education records. See 34 CFR 99.30 (FERPA), 300.622 (IDEA). In addition, parents remain protected by the IDEA "no-cost" regulations that prohibit public agencies from requiring parents to enroll in public benefits or insurance in order for their child to receive FAPE and using public benefits or insurance to pay for special education and related services if such use would result in additional specific costs to the parent or reduce benefits to the child. See § 300.154(d)(2)(i) through (iii). Finally, we propose to retain an annual notification requirement in § 300.154(d)(2)(v), which would include written notification of the "no-cost" provisions described above. Preserving such notification would ensure that the child's parents are continually informed of their rights and protections under the IDEA.

The proposed amendment to § 300.154(d)(2) would help address unequal funding access for certain Medicaid services that are available to both children with disabilities and children without disabilities (as covered services may be delivered to all Medicaid-enrolled students). As noted above, CMS' 2014 guidance clearly

indicated that Medicaid funds could be used to pay for services furnished to Medicaid-eligible students, even if the services were provided within a school at no cost to such students. The IDEA one-time consent provision within current § 300.154(d)(2)(iv) creates a barrier to accessing Medicaid for IDEA-eligible children that does not exist for non-IDEA-eligible children. The Secretary believes it is inappropriate to maintain such a barrier in light of the Biden-Harris Administration's goals of increasing access to health and mental health services for all youth.

Reducing the administrative burden for all parties is consistent with the Administration's goals and the Bipartisan Safer Communities Act's directive to increase access to Medicaid funding for health services in schools. With this change, parents would continue to retain their privacy rights and schools would have greater access to an important funding stream to support the provision of FAPE to eligible children with disabilities.

Executive Orders 12866 and 13563

Regulatory Impact Analysis

Under Executive Order 12866, the Office of Management and Budget (OMB) must determine whether this regulatory action is "significant" and, therefore, subject to the requirements of the Executive order and subject to review by OMB. Section 3(f) of Executive Order 12866 defines a "significant regulatory action" as an action likely to result in a rule that may—

(1) Have an annual effect on the economy of \$100 million or more, or adversely affect a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities in a material way (also referred to as an "economically significant" rule);

(2) Create serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impacts of entitlement grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles stated in the Executive order.

This proposed regulatory action is not a significant regulatory action subject to review by OMB under section 3(f) of Executive Order 12866.

We have also reviewed the proposed regulation under Executive Order 13563, which supplements and

explicitly reaffirms the principles, structures, and definitions governing regulatory review established in Executive Order 12866. To the extent permitted by law, Executive Order 13563 requires that an agency—

(1) Propose or adopt regulations only on a reasoned determination that their benefits justify their costs (recognizing that some benefits and costs are difficult to quantify);

(2) Tailor its regulations to impose the least burden on society, consistent with obtaining regulatory objectives and taking into account—among other things and to the extent practicable—the costs of cumulative regulations;

(3) In choosing among alternative regulatory approaches, select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity);

(4) To the extent feasible, specify performance objectives, rather than the behavior or manner of compliance a regulated entity must adopt; and

(5) Identify and assess available alternatives to direct regulation, including economic incentives—such as user fees or marketable permits—to encourage the desired behavior, or provide information that enables the public to make choices.

Executive Order 13563 also requires an agency “to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible.” The Office of Information and Regulatory Affairs of OMB has emphasized that these techniques may include “identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes.”

We are issuing the proposed regulation only on a reasoned determination that its benefits would justify its costs. We are issuing this proposed regulation after conducting a policy review per the Bipartisan Safer Communities Act and determining that the proposed changes closely adhere to policy goals of the Biden-Harris Administration. In choosing among alternative regulatory approaches, we selected the approach that maximizes net benefits. Based on the analysis that follows, the Department believes that this regulation is consistent with the principles in Executive Order 13563.

We also have determined that this regulatory action does not unduly interfere with State, local, or Tribal governments in the exercise of their governmental functions.

In accordance with both Executive orders, the Department has assessed the potential costs and benefits, both quantitative and qualitative, of this regulatory action. The potential costs associated with this regulatory action are those resulting from statutory requirements and those we have determined as necessary for administering the Department’s programs and activities. The potential benefits for LEAs include reduced administrative burden associated with the removal of the additional Federal consent requirement, and increased revenue for schools to enhance programs for students with disabilities and the provision of IDEA services as a result of leveraging Medicaid funding.

Discussion of Costs and Benefits

The Department has reviewed these proposed regulations to assess their potential impact. Based on the information provided by States in the Federal fiscal year 2020 State Performance Plan/Annual Performance Report,¹⁵ the Department determined that approximately 524,652 children were found eligible for special education in school year 2020–2021. Data indicates that 56 percent of children with disabilities are covered through Medicaid or the Children’s Health Insurance Program. Therefore approximately 293,805 of these children are determined to be eligible for Medicaid in the 2020–2021 school year. As a result, we assume 524,652 new students will enroll in IDEA Part B each year, of which 293,805 would be eligible for Medicaid. As detailed further below, we estimate that the reduced administrative burden associated with the removal of IDEA Medicaid consent requirements would have an initial first-year cost of \$2,484,856 and initial first-year benefit of \$5,981,870. For the first ten years, the overall benefit to impacted agencies and individuals would be \$39,691,856 using a 7 percent discount rate and \$48,614,083 using a 3 percent discount rate. This estimate assumes that all 51 State educational agencies¹⁶ (SEAs) currently accessing

Medicaid to pay for covered services utilize a joint form for requesting FERPA and IDEA parent consent to disclose PII under Part B of IDEA (§ 300.622) and FERPA (§ 99.30).

Costs

We estimate that costs of this proposed rule to state educational agencies (SEAs) would account for \$60,792 of our total estimated first-year costs of \$2,484,856. We assume that an Education Administrator and lawyer from each SEA would require two hours each to read and understand the proposed rule. We estimate that the cost per SEA of these proposed regulatory changes would be no more than \$525, for a national cost of \$26,775. In addition, we assume that it would take no more than 3 hours per SEA for a lawyer to revise the joint SEA IDEA and FERPA consent forms; we estimate the cost of revising the consent form to be no more than \$427 per SEA, for a national cost of \$21,777. We assume it would take 2 hours for an Education Administrator to draft guidance to LEAs on the revisions to consent forms and impact on LEAs; we estimate the cost of providing guidance to SEAs to be \$240 per SEA, for a national cost of \$12,240. These estimates are calculated using average national wage rates for Education Administrators employed by States of \$120.15¹⁷ and lawyers employed by State governments of \$142.34.¹⁸

We estimate that costs of this proposed rule to LEAs would account for \$2,424,064 of our total estimated first-year costs of \$2,484,856. We assume that, for each of the 17,824 LEAs,¹⁹ an Education Administrator would require 30 minutes and an Administrative Assistant from each LEA would require two hours to ensure LEA forms align with revised State forms. We estimate that the cost per LEA for ensuring that LEA consent forms align with revised SEA forms would be no more than \$136, for a national cost of \$2,424,064. These estimates are

¹⁷ As reported in the national Compensation Survey, May 2021 National Occupational Employment and Wage Estimates (https://www.bls.gov/oes/current/oes_nat.htm#00-0000) with 100 percent loaded wage rate.

¹⁸ As reported in the national Compensation Survey, May 2021 National Occupational Employment and Wage Estimates (https://www.bls.gov/oes/current/oes_nat.htm#00-0000) with 100 percent loaded wage rate.

¹⁹ As reported in the National Center for Education Statistics, Common Core of Data Elementary/Secondary Information System table generator with data compiled from a district based table with the following filters applied: 2021–22 school year, 50 States plus Washington, DC, excludes records with missing values, and includes districts with enrollment greater than zero.

¹⁵ <https://aspe.hhs.gov/sites/default/files/documents/77d7cc41648a371e0b5128f0dec2470e/aspe-childrens-health-coverage.pdf>.

¹⁶ Under Part B of the IDEA, there are 60 SEAs, which include the 50 States, the District of Columbia, Puerto Rico, the Bureau of Indian Education, the outlying areas (the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands), and the freely associated States (the Marshall Islands, the Federated States of Micronesia, and the Republic of Palau). For the purposes of this regulatory impact analysis, we include only the 50 States and the District of Columbia, which represent the SEAs that access Medicaid to pay for covered services.

calculated using average national wage rates for education administrators employed by local governments of \$118.58²⁰ and administrative assistants employed by local governments of \$38.54.²¹

Benefits

Overall, the Department estimates the proposed regulations would result in cost savings of \$5,981,870 during the first year due to a reduction in time and effort on the part of both LEA staff and parents. We estimate that, as a result of this proposed rule, cost reductions to LEAs equal to \$4,924,172 and benefits to parents equal to \$1,057,698 during the first year. We assume that for each of the 293,805 new students eligible to receive services under Medicaid, Special Education Teachers and parents would benefit as a result of this proposed rule due to time saved resulting from the removal of IDEA requirements from standard Medicaid consent forms. We estimate a benefit to LEAs of \$16.76 per student, for a national benefit of \$4,924,172 for time saved (15 minutes saved for each eligible student), because it would take Special Education Teachers less time to explain and review the IDEA-specific sections of Medicaid consent forms. We estimate a benefit to parents of \$3.60 per student, for a national benefit of \$1,057,698, due to a reduction in time required for a parent to review and understand the IDEA-specific sections of Medicaid consent forms. These estimates are calculated using the average national wage rate for special education teachers employed by local governments of \$67.05²² and, for parents, the 25th percentile of the average national wage rate for all occupations of \$14.40.²³

Elsewhere in this section under *Paperwork Reduction Act of 1995*, we identify and explain burdens specifically associated with information collection requirements.

²⁰ As reported in the national Compensation Survey, May 2021 National Occupational Employment and Wage Estimates (https://www.bls.gov/oes/current/oes_nat.htm#00-0000) with 100 percent loaded wage rate.

²¹ As reported in the national Compensation Survey, May 2021 National Occupational Employment and Wage Estimates (https://www.bls.gov/oes/current/oes_nat.htm#00-0000) with 100 percent loaded wage rate.

²² As reported in the national Compensation Survey, May 2021 National Occupational Employment and Wage Estimates (https://www.bls.gov/oes/current/oes_nat.htm#00-0000) with 100 percent loaded wage rate.

²³ As reported in the national Compensation Survey, May 2021 National Occupational Employment and Wage Estimates (https://www.bls.gov/oes/current/oes_nat.htm#00-0000) without loading.

Alternatives Considered

The Department reviewed and assessed various alternatives to the proposed regulations. The Department considered removing both the consent requirement and the notice provision. The Department also considered maintaining the current regulations requiring the one-time consent prior to the first time an LEA sought to bill a child or parent's public benefits or insurance and the notification provision prior to and an annually thereafter. The Department determined that removing the one-time consent and retaining the annual notification was the most efficient option to decrease administrative burden, ensure equal treatment of Medicaid-eligible children with disabilities and their nondisabled peers, and maintain transparency for parents.

Clarity of the Regulation

Executive Order 12866 and the Presidential memorandum "Plain Language in Government Writing" require each agency to write regulations that are easy to understand. The Secretary invites comments on how to make the regulation easier to understand, including answers to questions such as the following:

- Are the requirements in the proposed regulation clearly stated?
- Does the proposed regulation contain technical terms or other wording that interferes with its clarity?
- Does the format of the proposed regulation (use of headings, paragraphing, etc.) aid or reduce its clarity?
- Would the proposed regulation be easier to understand if we divided it into more (but shorter) sections? (A "section" is preceded by the symbol "\$" and a numbered heading; for example, § 106.9 Dissemination of policy.)
- Could the description of the proposed regulation in the **SUPPLEMENTARY INFORMATION** section of this preamble be more helpful in making the proposed regulation easier to understand? If so, how?
- What else could we do to make the proposed regulation easier to understand?

To send any comments that concern how the Department could make these proposed regulations easier to understand, see the instructions in the **ADDRESSES** section.

Regulatory Flexibility Act Certification

The Secretary certifies that the proposed regulation would not have a significant economic impact on a

substantial number of small entities. The U.S. Small Business Administration Size Standards define proprietary institutions as small businesses if they are independently owned and operated, are not dominant in their field of operation, and have total annual revenue below \$7,000,000. Nonprofit institutions are defined as small entities if they are independently owned and operated and not dominant in their field of operation. Public institutions are defined as small organizations if they are operated by a government overseeing a population below 50,000.

The small entities that this proposed regulatory action would affect are school districts or other public agencies seeking to access public insurance and benefits to reimburse services required to be provided to students with disabilities under IDEA Part B. The Secretary believes that the costs imposed on public agencies by the proposed regulation would be limited to the paperwork burden related to preparing the appropriate parental notice and that the benefits of implementing this proposal would outweigh any costs incurred by those agencies. As described in the *Discussion of Costs and Benefits* section of this document, the Department estimates that the proposed regulations would result in cost savings.

The Department invites comment from members of the public regarding our estimates and whether this proposed rule may have a significant economic impact on a substantial number of small entities.

Paperwork Reduction Act of 1995

As part of its continuing effort to reduce paperwork and respondent burden, the Department provides the general public and Federal agencies with an opportunity to comment on proposed and continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3506(c)(2)(A)). This helps ensure that the public understands the Department's collection instructions, respondents can provide the requested data in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the Department can properly assess the impact of collection requirements on respondents.

Proposed newly redesignated § 300.154(d)(iv) contains an information collection requirement, although the information collected is not submitted to the Department. Under the PRA, the Department has submitted a copy of this section to OMB for its review.

A Federal agency may not conduct or sponsor a collection of information unless OMB approves the collection under the PRA and the corresponding information collection instrument displays a currently valid OMB control number. Notwithstanding any other provision of law, no person is required to comply with, or is subject to penalty for failure to comply with, a collection of information if the collection instrument does not display a currently valid OMB control number.

In the final regulations, we will display the control number 1820–0600 assigned by OMB to any information collection requirement proposed in this NPRM and adopted in the final regulations.

Under proposed newly redesignated § 300.154(d)(2)(iv), each LEA must

provide a written notification to parents prior to accessing a child's or parent's public benefits or insurance for the first time and annually thereafter. We assume that each SEA would amend the standard notice that its LEAs can use and that it would take an average of about 10 hours to amend the notice for each of the 51 grantees currently accessing Medicaid to pay for covered services under Part B of IDEA, representing a total burden of 510 hours. We further estimate that as an uppermost bound it would take an additional 8,912 hours for LEA staff to obtain and modify an existing model notification, based on not more than 30 minutes for each of the 17,824 LEAs. However, we expect that most LEAs would simply use the model from its

SEA. Therefore, we estimate the one-time burden for the first year of implementation of this notification requirement to be not more than 9,422 hours. With the addition of the burden to SEAs and LEAs associated with proposed § 300.154, the total annual record keeping and notification burden for 1820–0600 is estimated to be approximately 383,751 hours for the 75,527 separate responses from SEAs and LEAs.

The following chart describes the sections of the proposed regulations involving information collections, the information being collected, and the collections the Department will submit to OMB for approval and public comment under the PRA.

Regulatory section	Collection information	OMB control number and estimated burden
§ 300.154(d)	Requires that parents receive a written notification prior to LEAs accessing a child's or parent's public benefits or insurance for the first time and annually thereafter.	Information collection 1820–0600 “State and Local Educational Agency Record Keeping, Notification, and Reporting Requirements under Part B of the Individuals with Disabilities Education Act.” The burden would be 9,422 hours.

We have prepared an Information Collection Request (ICR) for this collection. This proposed collection is identified as proposed collection OMB control number 1820–0600. If you want to review and comment on the ICR, please follow the instructions listed below in this section. Please note that the Office of Information and Regulatory Affairs (OIRA) and the Department of Education review all comments posted at www.regulations.gov.

We consider your comments on this proposed collection of information in—

- Deciding whether the proposed collection is necessary for the proper performance of our functions, including whether the information will have practical use;
- Evaluating the accuracy of our estimate of the burden of the proposed collection, including the validity of our methodology and assumptions;
- Enhancing the quality, usefulness, and clarity of the information we collect; and
- Minimizing the burden on those who must respond. This includes exploring the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Comments submitted in response to this document should be submitted electronically through the Federal eRulemaking Portal at www.regulations.gov by selecting Docket ID Number ED–2022–OSERS–

0052. Please specify the Docket ID number and indicate “Information Collection Comments” if your comment(s) relate to the information collection for this proposed rule. Written requests for information or comments submitted by postal mail or delivery should be addressed to the Strategic Collections and Clearance Director, U.S. Department of Education, 400 Maryland Avenue SW, LBJ Room 6W201, Washington, DC 20202–8240. For further information contact ICDocketMgr@ed.gov.

Consistent with 5 CFR 1320.8(d), the Department is soliciting comments on the information collection through this document. OMB is required to make a decision concerning the collection of information contained in these proposed regulations between 30 and 60 days after publication of this document in the **Federal Register**. Therefore, to ensure that OMB gives your comments full consideration, it is important that OMB receives your comments by June 20, 2023. This does not affect the deadline for your comments to us on the proposed regulations.

Intergovernmental Review

This program is subject to Executive Order 12372 and the regulations in 34 CFR part 79. One of the objectives of the Executive order is to foster an intergovernmental partnership and a strengthened federalism by relying on processes developed by State and local

governments for coordination and review of proposed Federal financial assistance.

This document provides early notification of the Department's specific plans and actions for this program.

Federalism

Executive Order 13132 requires us to ensure meaningful and timely input by State and local elected officials in the development of regulatory policies that have federalism implications. “Federalism implications” means 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. The proposed regulation does not have federalism implications.

Accessible Format: On request to the program contact person listed under **FOR FURTHER INFORMATION CONTACT**, individuals with disabilities can obtain this document in an accessible format. The Department will provide the requestor with an accessible format that may include Rich Text Format (RTF) or text format (txt), a thumb drive, an MP3 file, braille, large print, audiotape, or compact disc, or other accessible format.

Electronic Access to This Document: The official version of this document is the document published in the **Federal Register**. You may access the official edition of the **Federal Register** and the

Code of Federal Regulations at www.govinfo.gov. At this site you can view this document, as well as all other documents of this Department published in the **Federal Register**, in text or PDF. To use PDF you must have Adobe Acrobat Reader, which is available at no cost to the user at the site.

You may also access documents of the Department published in the **Federal Register** by using the article search feature at www.federalregister.gov. Specifically, through the advanced search feature at this site, you can limit your search to documents published by the Department.

List of Subjects in 34 CFR Part 300

Administrative practice and procedure, Education of individuals with disabilities, Elementary and secondary education, Equal educational opportunity, Grant programs—education, Privacy, Private schools, Reporting and recordkeeping requirements.

Miguel A. Cardona,
Secretary of Education.

For the reasons discussed in the preamble, the Secretary of Education proposes to revise part 300 of title 34 of the Code of Federal Regulations as follows:

PART 300—ASSISTANCE TO STATES FOR THE EDUCATION OF CHILDREN WITH DISABILITIES

■ 1. The authority citation for part 300 continues to read as follows:

Authority: 20 U.S.C. 1221e-3, 1406, 1411–1419, and 3474; Pub. L. 111–256, 124 Stat. 2643; unless otherwise noted.

■ 2. Section 300.154 is amended by:
■ a. Removing paragraph (d)(2)(iv);
■ b. Redesignating paragraph (d)(2)(v) as paragraph (d)(2)(iv); and
■ c. Revising newly redesignated paragraph (d)(2)(iv).

The revision reads as follows:

§ 300.154 Methods of ensuring services.

* * * * *

(d) * * *

(2) * * *

(iv) Prior to accessing a child's or parent's public benefits or insurance for the first time, and annually thereafter, must provide written notification to the child's parents, consistent with § 300.503(c), that includes—

(A) A statement confirming that parental consent to disclose personally identifiable information is required separately under 34 CFR 99.30 and 300.622 and that parents retain all applicable privacy rights under those provisions; and

(B) A statement of the “no cost” provisions in paragraphs (d)(2)(i) through (iii) of this section.

* * * * *

[FR Doc. 2023–10542 Filed 5–16–23; 4:15 pm]

BILLING CODE 4000–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2023–0069; FRL–10579–04–OCSPP]

Receipt of a Pesticide Petition Filed for Residues of Pesticide Chemicals in or on Various Commodities (April 2023)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of filing of petition and request for comment.

SUMMARY: This document announces the Agency's receipt of an initial filing of a pesticide petition requesting the establishment or modification of regulations for residues of pesticide chemicals in or on various commodities.

DATES: Comments must be received on or before June 20, 2023.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2023–0069, through the *Federal eRulemaking Portal* at <https://www.regulations.gov>. Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Additional instructions on commenting and visiting the docket, along with more information about dockets generally, is available at <https://www.epa.gov/dockets>.

FOR FURTHER INFORMATION CONTACT: Madison Le, Biopesticides and Pollution Prevention Division (BPPD) (7511M), main telephone number: (202) 566–1400, email address: BPPDFRNotices@epa.gov. The mailing address for each contact person is Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001. As part of the mailing address, include the contact person's name, division, and mail code. The division to contact is listed at the end of each application summary.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural

producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When preparing and submitting your comments, see the commenting tips at <https://www.epa.gov/dockets/commenting-epa-dockets>.

3. *Environmental justice.* EPA seeks to achieve environmental justice, the fair treatment and meaningful involvement of any group, including minority and/or low-income populations, in the development, implementation, and enforcement of environmental laws, regulations, and policies. To help address potential environmental justice issues, the Agency seeks information on any groups or segments of the population who, as a result of their location, cultural practices, or other factors, may have atypical or disproportionately high and adverse human health impacts or environmental effects from exposure to the pesticides discussed in this document, compared to the general population.

II. What action is the Agency taking?

EPA is announcing receipt of a pesticide petition filed under section 408 of the Federal Food, Drug, and Cosmetic Act (FFDCA), 21 U.S.C. 346a,

requesting the establishment or modification of regulations in 40 CFR part 180 for residues of pesticide chemicals in or on various food commodities. The Agency is taking public comment on the request before responding to the petitioner. EPA is not proposing any particular action at this time. EPA has determined that the pesticide petition described in this document contains data or information prescribed in FFDCA section 408(d)(2), 21 U.S.C. 346a(d)(2); however, EPA has not fully evaluated the sufficiency of the submitted data at this time or whether the data supports granting of the pesticide petition. After considering the public comments, EPA intends to evaluate whether and what action may be warranted. Additional data may be needed before EPA can make a final determination on this pesticide petition.

Pursuant to 40 CFR 180.7(f), a summary of the petition that is the subject of this document, prepared by the petitioner, is included in a docket EPA has created for this rulemaking.

The docket for this petition is available at <https://www.regulations.gov>.

As specified in FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), EPA is publishing notice of the petition so that the public has an opportunity to comment on this request for the establishment or modification of regulations for residues of pesticides in or on food commodities. Further information on the petition may be obtained through the petition summary referenced in this unit.

Notice of Filing—New Tolerance Exemptions for Non-Inerts (Except PIPS)

1. *PP 2F9022*. EPA–HQ–OPP–2023–0217. Valto BV, Leehove 81, 2678 MB De Lier Zuid-Holland, 2678–MB, Netherlands (c/o SciReg., Inc. 12733 Director's Loop Woodbridge, VA 22192), requests to establish an exemption from the requirement of a tolerance in 40 CFR part 180 for residues of the virucides Pepino mosaic virus, strain LP, isolate VX1 and Pepino mosaic virus, strain CH2, isolate VC1 in or on all food

commodities. The petitioner believes no analytical method is needed because it is not applicable. *Contact*: BPPD.

2. *PP 2F9031*. EPA–HQ–OPP–2023–0241. Lavie-Bio Ltd., Gad Feinstein 13, Rehovot 41732, Israel (c/o Delta Analytical Corporation, 12510 Prosperity Drive, Suite 160, Silver Spring, MD 20904), requests to establish an exemption from the requirement of a tolerance in 40 CFR part 180 for residues of the fungicide *Pseudomonas coleopterorum* strain 49762 in or on all food commodities. The petitioner believes no analytical method is needed because it is not applicable. *Contact*: BPPD.

Authority: 21 U.S.C. 346a.

Dated: May 9, 2023.

Delores Barber,

Director, Information Technology and Resources Management Division, Office of Program Support.

[FR Doc. 2023–10547 Filed 5–17–23; 8:45 am]

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Notices

Federal Register

Vol. 88, No. 96

Thursday, May 18, 2023

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

Rural Housing Service

[Docket No. RHS–23–SFH–0004]

Notice of Funding Availability for the Native Community Development Financial Institution (NCDFI) Relending Demonstration Program FY 2023

AGENCY: Rural Housing Service, USDA.

ACTION: Notice of funding availability.

SUMMARY: The Rural Housing Service (RHS or the Agency), an agency within the Rural Development mission area (RD) of the United States Department of Agriculture (USDA), announces the availability of funding for applications under its Native Community Development Financial Institution (NCDFI) Relending Demonstration Program for fiscal year (FY) 2023. The purpose of this notice is to announce the opening and closing dates for receipt of applications for the NCDFI Relending Demonstration Program from eligible applicants, as well as submission requirements. These loans will be made to qualified NCDFIs to relend funds to low- and very low-income ultimate recipients to acquire, build, rehabilitate, improve, or relocate dwellings on Tribal Land in rural areas. This program has \$7,502,000 available for FY 23. Applicants are responsible for any expenses incurred in developing their applications.

DATES: Completed applications must be submitted using one of the following methods:

- *Paper submissions:* The Agency must receive a paper application by 4:30 p.m. local time, July 17, 2023. Application can be mailed to: USDA Rural Development, Washington State Office, Attention: Andria Hively, 1835 Black Lake Blvd. SW, Olympia, WA 98512.
- *Electronic submissions:* Electronic applications must be submitted via

email to brian.hudson@usda.gov by 11:59 p.m. Eastern Time (ET) on July 17, 2023.

The Agency will not solicit or consider scoring or eligibility information that is submitted after the application deadline. The application dates and times are firm. The Agency will not consider any application received after the deadline. The Agency reserves the right to contact applicants to seek clarification information on materials contained in the submitted application.

ADDRESSES: Applicants wanting to apply for assistance may download the application documents and requirements as stated in this Notice from the NCDFI Relending Demonstration website at: <https://www.rd.usda.gov/programs-services/single-family-housing-programs/native-community-development-financial-institution-relending-demonstration-program>. Applicants may also request paper application packages from the Rural Development National Office by emailing brian.hudson@usda.gov.

FOR FURTHER INFORMATION CONTACT: Brian Hudson, Finance and Loan Analyst, Single Family Housing Direct Division, Special Programs and New Initiatives Branch at (608) 697–7725 (voice) (this is not a toll-free number) or brian.hudson@usda.gov.

SUPPLEMENTARY INFORMATION:

Overview

Federal Agency Name: Rural Housing Service (RHS).

Funding Opportunity Title: Native Community Development Financial Institution (NCDFI) Relending Demonstration Program.

Announcement Type: Notice of Funding Availability (NOFA).

Assistance Listing (AL) Numbers: 10.410.

Dates: Completed applications and supporting materials must be sent via mail or delivered to: USDA Rural Development, Washington State Office, Attention: Andria Hively, 1835 Black Lake Blvd. SW, Olympia, WA 98512 by 4:30 p.m. Pacific Time (PT) on July 17, 2023, or sent via email to brian.hudson@usda.gov by 11:59 p.m. Eastern Time (ET) on July 17, 2023. Late or incomplete applications will not be accepted.

Rural Development Key Priorities: The Agency encourages applicants to

consider projects that will advance the following key priorities (more details available at <https://www.rd.usda.gov/priority-points>):

- Reducing climate pollution and increasing resilience to the impacts of climate change through economic support to rural communities;
- Ensuring all rural residents have equitable access to RD programs and benefits from RD funded projects; and
- Assisting rural communities recover economically through more and better market opportunities and through improved infrastructure.

For further information, visit <https://www.rd.usda.gov/priority-points>.

A. Program Description

1. *Purpose of the Program.* The purpose of the NCDFI Relending Demonstration Program is to increase homeownership opportunities for Native American Tribes, Alaska Native Communities, and Native Hawaiian Communities in rural areas. The program will provide capital to NCDFIs; loans made to NCDFIs will be relent to the ultimate recipients (low- and very low-income people who will live on Tribal Lands and are in need of affordable, modest single-family homes).

2. *Statutory Authority.* Funding is authorized pursuant to the Consolidated Appropriation Act, 2023, Public Law 117–328, and Section 502 of the Housing Act of 1949, 42 U.S.C. 1472, implemented under 7 CFR part 3550.

3. *Definitions.* In addition to the terms defined below, the definitions and terms applicable to the loan process for ultimate recipients can be found at 7 CFR 3550.10):

a. Native Community Development Financial Institution (NCDFI). An entity that has been certified as a Native Community Development Financial Institution (NCDFI) by the Secretary of the Treasury; that is not less than 50 percent owned or controlled by members of Native American Tribes, Alaska Native Communities, or Native Hawaiian Communities; and for which not less than 50 percent of the activities of the entity serve Indian Tribes, Alaska Native communities, or Native Hawaiian communities;

b. Native Hawaiian. The term ‘Native Hawaiian’ has the meaning given the term in the Native American Housing Assistance and Self-Determination Act of 1996 (25 U.S.C. 4221);

c. Principals of NCDFI. Members, officers, directors, and other individuals or entities directly involved in the operation and management (including setting policy) of an NCDFI.

d. Tribal Land. Tribal Land includes any of the following:

(i) any land located within the boundaries of—

(I) an Indian reservation, pueblo, or rancharia; or

(II) a former reservation within Oklahoma;

(ii) any land not located within the boundaries of an Indian reservation, pueblo, or rancharia, the title to which is held—

(I) in trust by the United States for the benefit of an Indian Tribe or an individual Indian;

(II) by an Indian Tribe or an individual Indian, subject to restriction against alienation under laws of the United States; or

(III) by a dependent Indian community;

(iii) any land located within a region established pursuant to section 7(a) of the Alaska Native Claims Settlement Act (43 U.S.C. 1606(a));

(iv) Hawaiian Homelands, as defined in the Native American Housing Assistance and Self-Determination Act of 1996 (25 U.S.C. 4221); or

(v) those areas or communities designated by the Assistant Secretary of Indian Affairs of the Department of the Interior that are near, adjacent, or contiguous to reservations where financial assistance and social service programs are provided to Indians because of their status as Indians.

e. Ultimate recipient. An individual that receives a mortgage loan from a NCDFI Relending Demonstration Program fund.

4. Application Awards. The Agency will review, evaluate and score applications received in response to this notice based on the provisions found in this notice. Awards under the NCDFI Relending Demonstration Program will be made on a competitive basis using specific selection criteria contained in this notice. The Agency advises all interested parties that all expenses incurred in applying for this Notice are the applicant's sole risk.

B. Federal Award Information

Type of Award: Loan.

Fiscal Year Funds: FY 2023.

Available Funds: \$7,502,000.

Award Amounts: A minimum loan request of \$800,000 is required. There is no maximum loan limit. Applications with requests larger than \$1 million will be evaluated and awarded, based on program demand.

Anticipated Award Date: September 15, 2023.

Performance Period: No loan shall be extended for a period exceeding 33 years. The interest rate will be one percent. Interest and principal payments will be scheduled annually. The initial principal and interest payment will be deferred by the Agency for 3 years. Loan funds must be disbursed and delivered to the ultimate recipients within three years from the date of loan closing.

Renewal or Supplemental Awards: None.

Type of Assistance Instrument: Direct loan.

Approximate Number of Awards: The Agency anticipates making five to seven awards.

C. Eligibility Information

1. Eligible Applicants. Eligible entities for these competitively awarded loans include certified NCDFI's as determined by the Community Development Financial Institutions Fund of the U.S. Department of the Treasury. Any delinquent debt to the Federal Government by the NCDFI or any principal of the NCDFI shall cause the NCDFI to be ineligible to receive any NCDFI Relending Demonstration Program loan funds. Agency loan funds may not be used to satisfy the debt.

Debarment and suspension information is required in accordance with 2 CFR part 180 (OMB's Guidelines to Agencies on Governmentwide Debarment and Suspension (Nonprocurement) (Non procurement) supplemented by 2 CFR part 417 (Nonprocurement Debarment and Suspension) if it applies. The section heading is "What information must I provide before entering into a covered transaction with a Federal agency?" located at 2 CFR 180.335. It is part of OMB's Guidance for Grants and Agreements concerning Governmentwide Debarment and Suspension. Applicants are not eligible if they have been debarred or suspended or otherwise excluded from, or ineligible for, participation in Federal assistance programs under 2 CFR parts 180 and 417.

2. Non-Eligible Applicants. Applications will not be considered for funding if they do not provide enough information to determine eligibility, are not suitable for evaluation, or are missing required elements as stated in this notice. All applications submitted must meet the eligibility in this notice and demonstrate that the loans will be made to ultimate recipients who meet the eligibility criteria in 7 CFR 3550.53 <https://www.ecfr.gov/current/title-7/>

subtitle-B/chapter-XXXV/part-3550/subpart-B/section-3550.53.

3. Cost Sharing or Matching. An NCDFI that receives a loan under this section shall be required to match not less than 20 percent of the amount received. The NCDFI must demonstrate ability to meet the required match, or the application will be deemed ineligible. Matching funds from other Federal programs are allowed, unless the statutory requirements of the program from which the matching funds are being committed state that program funds cannot be used as matching funds.

(a) Matching funds must be in the form of cash or confirmed funding commitments. Matching funds must also be committed for a period of not less than the loan disbursement period of 3 years.

(b) In-kind contributions such as salaries, donated time and effort, real and nonexpendable personal property, and goods and services cannot be used as matching funds.

(c) The NCDFI is responsible for demonstrating that matching funds are available and committed. Matching funds may be provided by the NCDFI or a third party.

4. Discretionary Points. None.

5. Other. For FY 2023 applications the following additional eligibility requirements apply, and the application must address the applicant's proposal ensuring compliance with all program delivery requirements (available at the website: <https://www.ecfr.gov/current/title-7/subtitle-B/chapter-XXXV/part-3550/subpart-B/section-3550.53>).

(a) The NCDFI must have been legally organized for a minimum of three years and have at least one year prior experience working with residential mortgage lending. Applicants that do not meet this requirement can provide documentation regarding other related experience (e.g., staff expertise, other loan products, homeownership training, counseling and assistance, etc.) to justify that they have adequate experience to effectively and efficiently manage and repay a loan through this demonstration program;

(b) Proposals must be structured to utilize the funds, by making loans to eligible ultimate recipients, within 3 years from the date of award;

(c) A six percent reserve for bad debt or Loan Loss Reserve (LLR) will be required;

(d) An NCDFI proposing to serve ultimate recipients from one or more federally recognized Tribes must include letters of support with its application from the Tribe(s) and/or Tribally Designated Housing Entities/

Tribal Housing Authorities/Tribal Housing program(s) that serve those same ultimate recipients and/or a board resolution;

(e) Loan funds may not be used for payment of the NCDFI's administrative costs or expenses.

(f) Loans to ultimate recipients.

i. NCDFI Relending Demonstration Program loan funds must be used to provide direct loans made to eligible ultimate recipients in accordance with 7 CFR 3550. Loans from the NCDFI to the ultimate recipient using the NCDFI Relending Demonstration Program fund must be used to buy, build, rehabilitate, improve, or relocate an eligible dwelling in accordance with 7 CFR 3550.52(a) on Tribal Land, for use by the borrower as a permanent residence. The following regulatory requirements apply to loans made to ultimate recipients:

a. Eligible costs in accordance with 7 CFR 3550.52(d).

b. Restrictions on use of loan funds in accordance with 7 CFR 3550.52(e).

c. Ultimate recipient eligibility requirements in accordance with 7 CFR 3550.53.

d. Calculation of Ultimate recipients' income and assets in accordance with 7 CFR 3550.54.

e. Site requirements in accordance with 7 CFR 3550.56; site must also be located on Tribal Lands.

f. Dwelling requirement in accordance with 7 CFR 3550.57.

g. Ownership requirements in accordance with 7 CFR 3550.58.

h. Security requirements in accordance with 7 CFR 3550.59, except that NCDFIs need not use Agency closing forms, and security will be vested in the NCDFI and not to the agency.

For more information on how ultimate recipient loans can be processed, the Section 502 program Handbook-1-3550 can be found online at: <https://rd.usda.gov/resources/directives/handbooks>.

(ii) *Requests to make loans to ultimate recipients.* Prior Agency concurrence is required when an NCDFI requests a disbursement of the NCDFI Relending Demonstration Program loan funds to make a loan to an ultimate recipient. The request for Agency concurrence in approval of a proposed loan to an ultimate recipient must include:

(a) A certification by the NCDFI that:

i. The proposed ultimate recipient is eligible for the loan;

ii. The proposed loan is for eligible purposes;

iii. The proposed loan complies with all applicable statutes and regulations;

(b) Copies of sufficient material from the ultimate recipient's application and

the NCDFI's related files, to allow the Agency to determine the:

i. Name and address of the ultimate recipient;

ii. Loan purposes;

iii. Interest rate and term; and

iv. Confirmation of the NCDFI matching funds.

(g) *NCDFI Relending Program Loan Servicing Requirements.* NCDFI Relending Demonstration Program servicing requirements by the Agency are specified in this notice as follows:

(i) Quarterly reports are due 30 days after the end of each quarter as described below;

1. Reports will be required quarterly during the first year after loan closing and, if all loan funds are not utilized during the first year, quarterly reports will be continued until at least 90 percent of the Agency loan funds have been advanced to ultimate recipients. Thereafter, reports will be required semiannually. Also, the Agency may require quarterly reports if the NCDFI becomes delinquent in repayment of its loan or otherwise fails to fully comply with the provisions of its work plan or loan agreement, or the Agency determines that the NCDFI Relending Demonstration Program fund is not adequately protected by the current sound worth and paying capacity of the ultimate recipients.

2. These reports shall contain information on the NCDFI Relending Demonstration Program loan fund, and when other funds are included, the NCDFI Relending Demonstration Program portion shall be segregated from the others.

3. The reports will be collected on a form provided by the Agency and must include information on the NCDFI Relending Demonstration Program loan fund, NCDFI Relending Demonstration Program lending activity, income and expenses, financial condition and a summary of names and characteristics of the ultimate recipients the NCDFI has financed. When other funds are included in the reports, the NCDFI Relending Demonstration Program portion shall be segregated from the others.

(h) *Loan Closing Information*

1. The selected NCDFI will be issued a Letter of Conditions and be required to Complete Form RD 1942-46, "Letter of Intent to Meet Conditions", as applicable. Conditions may include but are not limited to completion of:

a. Form SF 3881, "ACH Vendor Payment Enrollment Form"

b. Form SF 270, "Request for Advance or Reimbursement"

c. HUD Form 935.2B, "Affirmative Fair Housing Marketing Plan—Single Family Housing"

d. Form RD 400-8, "Compliance Review"

2. The selected NCDFI will execute Form RD 1940-1, "Request for Obligation of Funds" prior to obligation.

3. The attorney, staff, or qualified professional for the NCDFI will work with USDA to prepare all necessary documents to close and secure the loan subject to USDA review and concurrence.

4. The NCDFI will be required to execute a Loan Agreement, Security Agreement, Promissory Note, and Deposit Agreement at closing. These items are available for review at the website: <https://www.rd.usda.gov/programs-services/single-family-housing-programs/native-community-development-financial-institution-relending-demonstration-program>.

5. A Financing Statement under the Uniform Commercial Code will be filed as security for the NCDFI Relending Demonstration Program loan funds account.

All applications submitted must meet the eligibility in this notice and demonstrate the loans will be made to ultimate recipients who meet the eligibility criteria in 7 CFR 3550.53 (<https://www.ecfr.gov/current/title-7/subtitle-B/chapter-XXXV/part-3550/subpart-B/section-3550.53>).

D. Application and Submission Information

1. *Address to Request Application Package.* Entities wishing to apply for assistance may acquire the application documents described in this notice from the NCDFI Relending Demonstration Program website: <https://www.rd.usda.gov/programs-services/single-family-housing-programs/native-community-development-financial-institution-relending-demonstration-program>.

Applicants may also request paper application packages from the Rural Development National Office by emailing brian.hudson@usda.gov.

2. *Content and Form of Application Submission.* If the applicant is ineligible or the application is incomplete, the Agency will inform the applicant in writing of the decision, reasons therefore, and its appeal rights and no further evaluation of the application will occur.

The Agency requires the following information to make an eligibility determination:

(i) Standard Form (SF)-424, "Application for Federal Assistance".

(ii) A written work plan to demonstrate the NCDFI's ability to meet the objectives of this notice. The plan must, at a minimum:

a. Document the NCDFI's ability to administer NCDFI Relending Demonstration Program funds in accordance with the provisions of this notice. To adequately demonstrate the ability to administer the program, the NCDFI must provide a complete listing of all personnel responsible for administering this program along with a statement of their qualifications and experience. The personnel may be board and/or loan committee members or employees of the NCDFI's organization or contract personnel hired for this purpose. If the personnel are to be contracted for, the contract between the NCDFI and the entity providing such service will be submitted for Agency review, and the terms of the contract and its duration must be sufficient to adequately service the Agency loan through to its maturity date. If the Agency determines the personnel lack the necessary expertise to administer the program, the loan request will not be approved;

b. Document the NCDFI's ability to commit financial resources under the control of the NCDFI to the establishment of an NCDFI Relending Demonstration Program. This should include a statement of the sources of non-Agency funds for administration of the NCDFI's operations and financial assistance for projects;

c. Demonstrate a need for loan funds. As a minimum, the NCDFI should identify a sufficient number of proposed and known ultimate recipients to justify Agency funding of its loan request, or include well developed targeting criteria for ultimate recipients consistent with the NCDFI's mission and strategy for the NCDFI Relending Demonstration Program, along with supporting statistical or narrative evidence that such prospective recipients exist in sufficient numbers to justify Agency funding of the loan request;

d. Include a list of proposed fees and other charges it will assess the ultimate recipients, if applicable;

e. Include the NCDFI's plan (specific loan purposes) for relending the loan funds. The plan must be of sufficient detail to provide the Agency with a complete understanding of what the NCDFI will accomplish by lending the funds to the ultimate recipient and the complete mechanics of how the funds will get from the NCDFI to the ultimate recipient. The service area, eligibility criteria, loan purposes, fees, rates, terms, collateral requirements, limits, priorities, application process, method

of disposition of the funds to the ultimate recipient, monitoring of the ultimate recipient's accomplishments, and reporting requirements by the ultimate recipient's management are items that must be addressed by the NCDFI's relending plan;

f. Provide a set of goals, strategies, and anticipated outcomes for the NCDFI's program. Outcomes should be expressed in quantitative or observable terms such as the number of homeowners assisted, and the number of homes financed, and should relate to the purpose of NCDFI Relending Demonstration Program; and

g. Provide specific information as to whether and how the NCDFI will ensure that technical assistance is made available to ultimate recipients and potential ultimate recipients. Describe the qualifications of the technical assistance providers, the nature of technical assistance that will be available, and expected and committed sources of funding for technical assistance. If other than the NCDFI itself, describe the organizations providing such assistance and the arrangements between such organizations and the NCDFI.

(iii) Environmental information on a form provided by the Agency (*Form RD 1970-B, Exhibit D*) for all projects positively identified as proposed ultimate recipient loans that are categorical exclusion actions under 7 CFR part 1970 subpart B.

(iv) A pro forma balance sheet at start-up and projected balance sheets for at least 3 additional years; financial statements for the last 3 years, or from inception of the operations of the NCDFI if less than 3 years; and projected cash flow and earnings statements for at least 4 years supported by a list of assumptions showing the basis for the projections. Principal repayment on the NCDFI Relending Demonstration Program loan will not be scheduled during the first 3 years, thus the projections for the NCDFI Relending Demonstration Program fund must extend to include a year with a full annual installment on the NCDFI Relending Demonstration Program loan.

(v) Statement of compliance with 2 CFR 200 and last financial audit report.

(vi) An agreement on a form provided by the Agency (*Form RD 400-4, "Assurance Agreement,"* and *Form RD 400-1, "Equal Opportunity Agreement"*) assuring compliance with title VI of the Civil Rights Act of 1964.

(vii) Complete organizational documents, including documentation of NCDFI certification status, Certificate of Good Standing, By-laws and Articles of Incorporation, and evidence of authority to conduct the proposed activities.

(viii) A form provided by the Agency (*Form RD 1910-11, "Applicant Certification Federal Collection Policies for Consumer or Commercial Debts"*) in which the applicant certifies its understanding of the Federal collection policies for consumer or commercial debts.

(ix) A statement on a form provided by the Agency (*Exhibit A-1 of RD Instruction 1940-Q*) regarding lobbying.

3. System for Award Management and Unique Entity Identifier.

(a) At the time of application, each applicant must have an active registration in the System for Award Management (SAM) before submitting its application in accordance with 2 CFR part 25. In order to register in SAM, entities will be required to create a Unique Entity Identifier (UEI). Instructions for obtaining the UEI are available at <https://sam.gov/content/entity-registration>.

(b) Applicants must maintain an active SAM registration, with current, accurate and complete information, at all times during which it has an active Federal award or an application under consideration by a Federal awarding agency.

(c) Applicants must ensure they complete the Financial Assistance General Certifications and Representations in SAM.

(d) Applicants must provide a valid UEI in their application, unless determined exempt under 2 CFR 25.110.

(e) The Agency will not make an award until the applicant has complied with all SAM requirements including providing the UEI. If an applicant has not fully complied with the requirements by the time the Agency is ready to make an award, the Agency may determine that the applicant is not qualified to receive a Federal award and use that determination as a basis for making a Federal award to another applicant.

4. *Submission Dates and Times.* The Agency will not solicit or consider new scoring or eligibility information that is submitted after the application deadline. RHS reserves the right to ask applicants for clarifying information and additional verification of assertions in the submitted application. Completed applications must be submitted using one of the following methods:

- *Paper submissions:* The Agency must receive a paper application by 4:30 p.m. Pacific Time (PT), July 17, 2023. Application can be mailed or delivered to: USDA Rural Washington State Office, Attention: Andria Hively, 1835 Black Lake Blvd. SW, Olympia, WA 98512.

• *Electronic submissions*: Electronic applications must be submitted via email to brian.hudson@usda.gov by 11:59 p.m. Eastern Time (ET) on July 17, 2023.

The application dates and times are firm. The Agency will not consider any application received after the deadline.

5. *Intergovernmental Review*. Not applicable.

6. *Funding Restrictions*. Expenses incurred in developing applications will be at the applicant's cost.

7. *Other Submission Requirements*. None.

(a) *Other Federal Statutes*. The applicant must certify to compliance with other Federal Statutes and regulations by completing the Financial Assistance General Certification and Representations in SAM, including, but not limited to the following:

(i) 7 CFR part 15, subpart A—Nondiscrimination in Federally Assisted Programs of the Department of Agriculture—Effectuation of Title VI of the Civil Rights Act of 1964. Civil Rights compliance includes, but is not limited to the following:

(A) Collect and maintain data provided by ultimate recipients on race, sex, and national origin and ensure that ultimate recipients collect and maintain this data.

(B) Race and ethnicity data will be collected in accordance with Office of Management and Budget (OMB) **Federal Register** notice, “Revisions to the Standards for the Classification of Federal Data on Race and Ethnicity” (published October 30, 1997, at 62 FR 58782); sex data will be collected in accordance with title IX of the Education Amendments of 1972. These items should not be submitted with the application but should be available upon request by RD.

(ii) The applicant and the ultimate recipient must comply with title VI of the Civil Rights Act of 1964, title IX of the Education Amendments of 1972, the Americans with Disabilities Act (ADA), Section 504 of the Rehabilitation Act of 1973, the Age Discrimination Act of 1975, Executive Order 12250, and 7 CFR part 1901, subpart E.

(iii) 2 CFR parts 200 and 400 (Uniform Administrative Requirements, Cost Principles and Audit Requirements for Federal Awards), or any successor regulation.

(iv) Executive Order 13166, “Improving Access to Services for Persons with Limited English Proficiency.” For information on limited English proficiency and agency-specific guidance, go to <https://www.lep.gov/>.

(v) Federal Obligation Certification on Delinquent Debt.

(b) *Risk Review*: RD may request additional documentation from selected applicants in order to evaluate the financial, management, and performance risk posed by awardees as required by 2 CFR 200.206. Based on this risk review, RD may apply special conditions that correspond to the degree of risk assessed.

E. Application Review Information

1. *Criteria*. All eligible and complete applications will be evaluated and scored based on the selection criteria contained in this notice. Failure to address any of the application criteria by the application deadline will result in the application being determined ineligible, and the application will not be considered for funding.

2. *Review and Selection Process*. The Agency reserves the right to offer the applicant less than the loan funding requested. Rural Development National Office will utilize the following threshold project selection criteria for applicants in accordance with this notice.

(a) Providing a financially feasible program for single family residential mortgage lending, which will result in affordable housing for very low- and low-income persons.

(b) Serving Tribal lands in an eligible rural area with affordable housing for very low- and low-income persons.

(c) Being an eligible applicant as defined in this notice.

(e) Submitting a complete application as outlined in this notice.

3. *Scoring*. For applicants meeting all the requirements listed above, the Rural Development National Office will use weighted criteria in accordance with this notice as selection for the loan recipients. Each application and its accompanying statement of activities will be evaluated and, based solely on the information contained in the application, the applicant's proposal will be numerically rated on each criterion within the range provided. The highest-ranking applicant(s) will be selected using the following criteria:

a. Years experience in residential mortgage lending:

(i) Less than one: 0 points

(ii) 1–2: 1 point

(iii) 3: 2 points

(iv) 4–5: 3 points

(v) More than 5 years: 4 points

b. Years experience in servicing residential mortgage loans:

(i) Less than one: 0 points

(ii) 1–2: 1 point

(iii) 3: 2 points

(iv) 4–5: 3 points

(v) More than 5 years: 4 points

c. Years experience managing a loan fund:

(i) Less than one: 0 points

(ii) 1–2: 1 point

(iii) 3: 2 points

(iv) 4–5: 3 points

(v) More than 5 years: 4 points

d. Years experience managing federal funds:

(i) Less than one: 0 points

(ii) 1–2: 1 point

(iii) 3: 2 points

(iv) 4–5: 3 points

(v) More than 5 years: 4 points

e. Matching funding:

(i) Less than 20%: Not Eligible

(ii) 20%–40%: 1 point

(iii) More than 40%–60%: 2 points

(iv) More than 60%–80%: 3 points

(v) More than 80%–100%: 4 points

4. *Anticipated Announcement and Federal Award Dates*. Awards will be made by September 15, 2023.

F. Federal Award Administration Information

1. *Federal Award Notices*. Successful applicants will receive notification for funding from the USDA Rural Development National Office. Applicants must comply with all applicable statutes and regulations before the loan award will be obligated. The Agency will notify, in writing, applicants that have been selected for funding. At the time of notification, the Agency will advise the applicant what further information and documentation, if any, is required along with a timeline for submitting the additional information. If at any point the Agency determines it is unable to select the application for funding, the applicant will be informed in writing. Such notification will include the reasons the applicant was not selected. The Agency will advise applicants whose applications did not meet eligibility and/or selection criteria of their review rights or appeal rights in accordance with 7 CFR 3550.4 and/or 7 CFR part 11.

2. *Administrative and National Policy Requirements*. The loan recipient must include the required nondiscrimination statements in any of their advertisements and brochures. The loan recipient will be required to collect and maintain data provided by the ultimate recipients on race, sex, and national origin and ensure recipients collect and maintain this data. Race and ethnicity data will be collected in accordance with OMB **Federal Register** notice, “Revisions to the Standards for the Classification of Federal Data on Race and Ethnicity,” (62 FR 58782), October 30, 1997. Data on recipients' sex will be collected in accordance with title IX of

the Education Amendments of 1972. These items should not be submitted with the application but should be available upon request by the Agency.

3. *Reporting.* Performance reporting, including applicable forms, narratives, and other documentation, are to be completed and submitted in accordance with the provisions of this notice and the loan documents referenced in the 'other' section of this notice. Further, all borrowers must submit an audit or financial information pursuant to 2 CFR part 200 covering the defined period of performance as outlined in this notice and the Agreements referenced in the 'other' section of this notice.

G. Federal Awarding Agency Contact(s)

For general questions about this announcement, please contact Brian Hudson, Finance and Loan Analyst, Single Family Housing Direct Division, Special Programs and New Initiatives Branch at (608) 697-7725 (voice) (this is not a toll-free number) or brian.hudson@usda.gov. Applicants wanting to apply for assistance may download the application documents and requirements as stated in this notice from the NCDFI Relending Demonstration Program website: <https://www.rd.usda.gov/programs-services/single-family-housing-programs/native-community-development-financial-institution-relending-demonstration-program>.

H. Other Information

1. *Paperwork Reduction Act.* RHS has concluded that the reporting requirements contained in this NOFA will involve less than 10 persons and does not require an approval under the provisions of the Act. In accordance with the Paperwork Reduction Act of 1995, (44 U.S.C. 3501 *et seq.*), OMB must approve all collection of information as a requirement for "answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *." (44 U.S.C. 3502(3)(A).)

2. *National Environmental Policy Act.* All recipients under this notice are subject to the requirements of 7 CFR part 1970 available at the website: <https://rd.usda.gov/resources/environmental-studies/environmental-guidance> and must comply in accordance with 7 CFR 3550.5.

3. *Federal Funding Accountability and Transparency Act.* All applicants, in accordance with 2 CFR part 25, must be registered in SAM and have a UEI number as stated in Section D.3, of this notice. All recipients of Federal financial assistance are required to report information about first-tier sub-

awards and executive total compensation in accordance with 2 CFR part 170.

4. *Civil Rights Act.* All loans made under this notice are subject to title VI of the Civil Rights Act of 1964 as required by the USDA (7 CFR part 15, subpart A—Nondiscrimination in Federally-Assisted Programs of the Department of Agriculture—Effectuation of Title VI of the Civil Rights Act of 1964) and section 504 of the Rehabilitation Act of 1973, title VIII of the Civil Rights Act of 1968, title IX, Executive Order 13166 (Limited English Proficiency), Executive Order 11246, and the Equal Credit Opportunity Act of 1974.

5. *Non-Discrimination Statement.* In accordance with Federal civil rights law and USDA civil rights regulations and policies, USDA, its Mission Areas, agencies, staff offices, employees and institutions participating in or administering USDA programs are prohibited from discrimination 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.

Program information may be made available in languages other than English. Persons with disabilities who require alternative means of communication to obtain program information (e.g., Braille, large print, audiotope, American Sign Language) should contact the responsible Mission Area, agency, or staff office; the USDA TARGET Center at (202) 720-2600 (voice and TTY); or the 711 Relay Service.

To file a program discrimination complaint, the complainant should complete the USDA Program Discrimination Complaint Form AD-3027 (PDF), which can be obtained online at: <https://www.usda.gov/oascr/how-to-file-a-program-discrimination-complaint>, from any USDA office, by calling (866) 632-9992 or by writing a letter addressed to USDA, and at any USDA office or write a letter addressed to USDA. The letter must contain the complainant's name, address, telephone number and a written description of the alleged discriminatory action in sufficient detail to inform the Assistant Secretary for Civil Rights (ASCR) about the nature and date of the alleged civil rights violation. The completed AD-

3027 form or letter must be submitted to USDA by:

(1) *Mail:* U.S. Department of Agriculture, Office of the Assistant Secretary for Civil Rights, 1400 Independence Avenue SW, Washington, DC 20250-9410; or

(2) *Fax:* (833) 256-1665 or (202) 690-7442; or

(3) *Email:* program.intake@usda.gov.

USDA is an equal opportunity provider, employer, and lender.

Joaquin Altoro,

Administrator, Rural Housing Service, USDA Rural Development.

[FR Doc. 2023-10605 Filed 5-17-23; 8:45 am]

BILLING CODE 3410-XV-P

DEPARTMENT OF AGRICULTURE

Rural Housing Service

Notice of Finding of No Significant Impact

AGENCY: Rural Housing Service, USDA.

ACTION: Notice.

SUMMARY: Notice is hereby given that the Rural Housing Service (RHS), as required by the National Environmental Policy Act, is issuing a Finding of No Significant Impact (FONSI) with respect to the preliminary affordability determination of minimum energy standards.

FOR FURTHER INFORMATION CONTACT: To obtain copies of the Environmental Assessment (EA) and FONSI, see <https://www.rd.usda.gov/resources/environmental-studies/hud-usda-joint-notice>. For additional information, contact Peggy Wade, Environmental Protection Specialist, Program Support Staff, Rural Housing Service, USDA—Rural Development, USDA, 202-875-3572; email: peggy.wade@usda.gov.

SUPPLEMENTARY INFORMATION: This action implements the requirements of Section 481 of the Energy Independence and Security Act of 1990 (the Act), which established procedures for the U.S. Department of Housing and Urban Development (HUD) and the U.S. Department of Agriculture (USDA) to adopt revisions to the 2006 International Energy Conservation Code (IECC) and ASHRAE90.1-2004, or subsequent revisions to these codes.

This notice addresses new construction of single-family homes financed under RHS's Section 502 Direct Loan, Section 502 Guaranteed Loan, or Section 523 Grant programs and announces USDA's preliminary determination that the 2021 IECC and ASHRAE 90.1-2019 codes will not

negatively affect the affordability or availability of housing covered by the Act. Therefore, RHS has determined that this FONSI fulfills its obligations under the National Environmental Policy Act, as amended (42 U.S.C. 4321 *et seq.*), the Council on Environmental Quality Regulations (40 CFR parts 1500 through 1508), and USDA Rural Development's Environmental Policies and Procedures (7 CFR part 1970) for its action related to the project. RHS's federal action would not result in significant impacts to the quality of the human environment, and as such it will not prepare an Environmental Impact Statement for its action related to the proposed project.

Joaquin Altoro,

Administrator, Rural Housing Service, Rural Development, USDA.

[FR Doc. 2023-10712 Filed 5-17-23; 8:45 am]

BILLING CODE P

COMMISSION ON CIVIL RIGHTS

Notice of Public Meeting of the New York Advisory Committee to the U.S. Commission on Civil Rights

AGENCY: U.S. Commission on Civil Rights.

ACTION: Notice of virtual business meeting.

SUMMARY: Notice is hereby given, pursuant to the provisions of the rules and regulations of the U.S. Commission on Civil Rights (Commission) and the Federal Advisory Committee Act, that the New York Advisory Committee (Committee) to the U.S. Commission on Civil Rights will hold a public meeting via Zoom. The purpose of the meeting is to discuss briefing planning and select panelists for the multi-sector panel VII on the New York child welfare system and its impact on Black children and families.

DATES: Friday, June 16, 2023, from 1:00 p.m.–3:00 p.m. Eastern Time.

ADDRESSES: The meeting will be held via Zoom.

Registration Link (Audio/Visual):
<https://tinyurl.com/5n7pcjvc>

Join by Phone (Audio Only): 1-833-435-1820 USA Toll-Free; Meeting ID: 160 209 3015#

FOR FURTHER INFORMATION CONTACT: Mallory Trachtenberg, DFO, at mtrachtenberg@usccr.gov or 1-202-809-9618.

SUPPLEMENTARY INFORMATION: This Committee meeting is available to the public through the registration link above. Any interested member of the

public may listen to the meeting. An open comment period will be provided to allow members of the public to make a statement as time allows. Per the Federal Advisory Committee Act, public minutes of the meeting will include a list of persons who are present at the meeting. If joining via phone, callers can expect to incur regular charges for calls they initiate over wireless lines, according to their wireless plan. The Commission will not refund any incurred charges. Callers will incur no charge for calls they initiate over land-line connections to the toll-free telephone number. Closed captioning is available by selecting “CC” in the meeting platform. To request additional accommodations, please email svillanueva@usccr.gov at least 10 business days prior to the meeting.

Members of the public are entitled to submit written comments; the comments must be received in the regional office within 30 days following the meeting. Written comments may be emailed to Malloy Trachtenberg at mtrachtenberg@usccr.gov. Persons who desire additional information may contact the Regional Programs Coordination Unit at 1-202-809-9618.

Records generated from this meeting may be inspected and reproduced at the Regional Programs Coordination Unit Office, as they become available, both before and after the meeting. Records of the meetings will be available via www.facadatabase.gov under the Commission on Civil Rights, New York Advisory Committee link. Persons interested in the work of this Committee are directed to the Commission's website, <http://www.usccr.gov>, or may contact the Regional Programs Coordination Unit at svillanueva@usccr.gov.

Agenda

- I. Welcome and Roll Call
- II. Approval of Minutes
- III. Briefing Planning and Panelist Selection Vote
- IV. Public Comment
- V. Next Steps
- VI. Adjournment

Dated: May 15, 2023.

David Mussatt,

Supervisory Chief, Regional Programs Unit.

[FR Doc. 2023-10677 Filed 5-17-23; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

Census Bureau

Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Census Household Panel; Correction

AGENCY: U.S. Census Bureau, Department of Commerce.

ACTION: Notice; correction.

SUMMARY: On May 11, 2023, the Department of Commerce, published a 30-day public comment period notice in the **Federal Register** with FR Document Number 2023-10040, Pages 30276–30277 seeking public comments for the information collection entitled, “Census Household Panel.” This document referenced incorrect information in the narrative, and Commerce hereby issues a correction notice as required by the Paperwork Reduction Act of 1995.

FOR FURTHER INFORMATION CONTACT: For additional information concerning this correction, contact Cassandra Logan, U.S. Census Bureau, (301) 763-1087 (or via the internet at Cassandra.logan@census.gov).

SUPPLEMENTARY INFORMATION:

Narrative section incorrectly stated:

Find this particular information collection by selecting “Currently under 30-day Review—Open for Public Comments” or by using the search function and entering either the title of the collection or the OMB Control Number 0607-1013.

Correction

Should have read:

Find this particular information collection by selecting “Currently under 30-day Review—Open for Public Comments” or by using the search function and entering the title of the collection.

Sheleen Dumas,

Department PRA Clearance Officer, Office of the Under Secretary for Economic Affairs, Commerce Department.

[FR Doc. 2023-10573 Filed 5-17-23; 8:45 am]

BILLING CODE 3510-07-P

DEPARTMENT OF COMMERCE

Foreign-Trade Zones Board

[B–7–2023]

Foreign-Trade Zone (FTZ) 129;
Authorization of Production Activity;
Corvus Energy USA, Ltd.; (Lithium-Ion
Battery Energy Storage Systems);
Bellingham, Washington

On January 12, 2023, Corvus Energy USA, Ltd. submitted a notification of proposed production activity to the FTZ Board for its facility within Subzone 129C, in Bellingham, Washington.

The notification was processed in accordance with the regulations of the FTZ Board (15 CFR part 400), including notice in the **Federal Register** inviting public comment (88 FR 4806, January 25, 2023). On May 12, 2023, the applicant was notified of the FTZ Board’s decision that no further review of the activity is warranted at this time. The production activity described in the notification was authorized, subject to the FTZ Act and the FTZ Board’s regulations, including section 400.14.

Dated: May 12, 2023.

Elizabeth Whiteman,
Executive Secretary.

[FR Doc. 2023–10580 Filed 5–17–23; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–201–842]

Large Residential Washers From
Mexico: Final Results of Antidumping
Duty Administrative Review; 2021–
2022

AGENCY: Enforcement and Compliance,
International Trade Administration,
Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) determines that large residential washers (washers) from Mexico were sold in the United States at less than normal value (NV) during the period of review (POR) February 1, 2021, through January 31, 2022.

DATES: Applicable May 18, 2023.

FOR FURTHER INFORMATION CONTACT:

Steven Seifert, AD/CVD Operations, Office II, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–3350.

SUPPLEMENTARY INFORMATION:

Background

This review covers one producer/exporter of the subject merchandise, Electrolux Home Products, Inc., Electrolux Home Products Corp. N.V. and Electrolux Home Products de Mexico, S.A. de C.V. (collectively, Electrolux). On March 2, 2023, Commerce published the preliminary results of this administrative review and invited interested parties to comment.¹ On April 3, 2023, we received a case brief on behalf of Electrolux.² We received no other comments from interested parties on the *Preliminary Results*. Commerce conducted this administrative review in accordance with section 751(a) of the Tariff Act of 1930, as amended (the Act).

Scope of the Order³

The products covered by the *Order* are all large residential washers and certain subassemblies thereof from Mexico. The products are currently classifiable under subheadings 8450.20.0040 and 8450.20.0080 of the Harmonized Tariff System of the United States (HTSUS). Products subject to this *Order* may also enter under HTSUS subheadings 8450.11.0040,

8450.11.0080, 8450.90.2000, and 8450.90.6000. Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the merchandise subject to this scope is dispositive.⁴

Analysis of Comments Received

We addressed all issues raised in the interested party’s case brief in the Issues and Decision Memorandum accompanying this notice.⁵ A list of the issues raised by parties, to which Commerce responded in the Issues and Decision Memorandum, is provided as an appendix to this notice. The Issues and Decision Memorandum is a public document and is on file electronically via Enforcement and Compliance’s Antidumping and Countervailing Duty Centralized Electronic Service System (ACCESS). ACCESS is available to registered users at <https://access.trade.gov>. In addition, a complete version of the Issues and Decision Memorandum can be accessed directly at <https://access.trade.gov/public/FRNoticesListLayout.aspx>.

Changes Since the Preliminary Results

Based on a review of the record and comments received from Electrolux regarding our *Preliminary Results*, we made certain changes to the preliminary weighted-average margin for Electrolux.⁶

Finals Results of Review

As a result of this review, we determine that the following weighted-average dumping margin exists for the respondent for the period February 1, 2021, through January 31, 2022:

Producer/exporter	Weighted-average dumping margin (percent)
Electrolux Home Products, Inc., Electrolux Home Products Corp. N.V., Electrolux Home Products de Mexico, S.A. de C.V	1.89

Disclosure of Calculations

We intend to disclose the calculations performed in connection with these final results to interested parties within five days of the date of publication of

this notice, in accordance with 19 CFR 351.224(b).

¹ See *Preliminary Results of Antidumping Duty Administrative Review; 2021–2022*, 88 FR 13097 (March 2, 2023), and accompanying Preliminary Decision Memorandum (PDM).

² See Electrolux’s Letter, “Electrolux’s Case Brief,” dated April 3, 2023.

³ See *Large Residential Washers from Mexico and the Republic of Korea: Antidumping Duty Orders*, 78 FR 11148 (February 15, 2013) (*Order*).

⁴ For a full description of the scope of the order, see the *Preliminary Results* PDM.

⁵ See Memorandum, “Decision Memorandum for the Final Results of the 2021–2022 Administrative

Assessment Rates

Pursuant to section 751(a)(2)(C) of the Act, and 19 CFR 351.212(b)(1), Commerce has determined, and U.S. Customs and Border Protection (CBP)

Review of the Antidumping Duty Order on Large Residential Washers from Mexico,” dated concurrently with, and hereby adopted by, this notice (Issues and Decision Memorandum).

⁶ See Issues and Decision Memorandum.

shall assess, antidumping duties on all appropriate entries of subject merchandise in accordance with the final results of this review.

Pursuant to 19 CFR 351.212(b)(1), Electrolux reported the entered value of its U.S. sales such that we calculated importer-specific *ad valorem* duty assessment rates based on the ratio of the total amount of dumping calculated for the examined sales to the total entered value of the sales for which entered value was reported. Where the respondent's weighted-average dumping margin is zero or *de minimis* within the meaning of 19 CFR 351.106(c)(1), or an importer-specific assessment rate is zero or *de minimis*, we will instruct CBP to liquidate the appropriate entries without regard to antidumping duties.

Commerce's "automatic assessment" practice will apply to entries of subject merchandise during the POR produced by Electrolux for which the company did not know that the merchandise it sold to the intermediary (e.g., a reseller, trading company, or exporter) was destined for the United States. In such instances, we will instruct CBP to liquidate unreviewed entries at the all-others rate of 36.52 percent⁷ if there is no rate for the intermediate company(ies) involved in the transaction.⁸

Commerce intends to issue liquidation instructions to CBP no earlier than 41 days after the date of publication of the final results of this review in the **Federal Register**. If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (i.e., within 90 days of publication).

Cash Deposit Requirements

The following cash deposit requirements will be effective for all shipments of the subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date of the final results of this administrative review, as provided by section 751(a)(2)(C) of the Act: (1) the cash deposit rate for the exporter listed above will be equal to the weighted-average dumping margin established in the final results of this review, except if the rate is less than 0.50 percent and, therefore, *de minimis* within the meaning of 19 CFR 351.106(c)(1), in which case the cash deposit rate will be

zero; (2) for companies not participating in this review, the cash deposit rate will continue to be the company-specific cash deposit rate published for the most recently completed segment; (3) if the exporter is not a firm covered in this review, or the original less-than-fair-value (LTFV) investigation, but the producer is, then the cash deposit rate will be the cash deposit rate established for the most recently completed segment for the producer of the merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 36.52 percent, the all-others rate established in the LTFV investigation.⁹ These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in the Secretary's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Administrative Protective Order

This notice serves as the only reminder to parties subject to administrative protective order (APO) of their responsibility concerning the disposition of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of return/destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and the terms of an APO is a sanctionable violation.

Notification to Interested Parties

We are issuing and publishing these results in accordance with sections 751(a)(1) and 777(i)(1) of the Act.

Dated: May 11, 2023.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Issues and Decision Memorandum

- I. Summary
- II. Background

⁹ See Order.

III. Changes Since the *Preliminary Results*
IV. Discussion of the Issue

Comment: Error in the Market Economy (ME) Macros Program
V. Recommendation

[FR Doc. 2023–10578 Filed 5–17–23; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–148]

Gas Powered Pressure Washers From the People's Republic of China: Postponement of Preliminary Determination in the Less-Than-Fair-Value Investigation

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

DATES: Applicable May 18, 2023.

FOR FURTHER INFORMATION CONTACT: Hermes Pinilla, AD/CVD Operations, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–3477.

SUPPLEMENTARY INFORMATION:

Background

On January 19, 2023, the U.S. Department of Commerce (Commerce) initiated the less-than-fair-value investigation (LTFV) of gas powered pressure washers from the People's Republic of China.¹ Currently, the preliminary determination is due no later than June 8, 2023.

Postponement of Preliminary Determination

Section 733(b)(1)(A) of the Tariff Act of 1930, as amended (the Act) requires Commerce to issue the preliminary determination in an LTFV investigation within 140 days of the date on which Commerce initiated the investigation. However, section 733(c)(1) of the Act permits Commerce to postpone the preliminary determination until no later than 190 days after the date on which Commerce initiated the investigation if: (A) the petitioner makes a timely request for a postponement; or (B) Commerce concludes that the parties concerned are cooperating, that the investigation is extraordinarily complicated, and that additional time is necessary to make a preliminary determination. Under 19 CFR 351.205(e), the petitioner must submit a

¹ See *Gas Powered Pressure Washers from the People's Republic of China and the Socialist Republic of Vietnam: Initiation of Less-Than-Fair-Value Investigations*, 88 FR 4807 (January 25, 2023).

⁷ See Order.

⁸ For a full discussion of this practice, see *Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties*, 68 FR 23954 (May 6, 2003).

request for postponement 25 days or more before the scheduled date of the preliminary determination and must state the reasons for the request. Commerce will grant the request unless it finds compelling reasons to deny the request.

On April 24, 2023, FNA Group, Inc. (the petitioner) submitted a timely request that Commerce postpone the preliminary determination in this LTFV investigation.² The petitioner stated that it requests postponement due to concerns that Commerce will need more time to issue supplemental questionnaires to address deficiencies in the respondents' initial questionnaire responses. Under the current timeline, the petitioner believes that Commerce will not have complete responses and sufficient information to prepare and issue the preliminary determination.³

For the reasons stated above, and because there are no compelling reasons to deny the request, Commerce, in accordance with section 733(c)(1)(A) of the Act and 19 CFR 351.205(e), is postponing the deadline for this preliminary determination by 50 days (*i.e.*, 190 days after the date on which these investigations were initiated). As a result, Commerce will issue its preliminary determination no later than July 28, 2023. In accordance with section 735(a)(1) of the Act and 19 CFR 351.210(b)(1), the deadline for the final determination in this investigation will continue to be 75 days after the date of the preliminary determination, unless postponed at a later date.

Notification to Interested Parties

This notice is issued and published pursuant to section 733(c)(2) of the Act and 19 CFR 351.205(f)(1).

Dated: May 11, 2023.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2023–10579 Filed 5–17–23; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC954]

Takes of Marine Mammals Incidental to Specified Activities; Taking Marine Mammals Incidental to SouthCoast Wind Energy, LLC's Marine Site Characterization Surveys Off Massachusetts and Rhode Island

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of an incidental harassment authorization.

SUMMARY: In accordance with the regulations implementing the Marine Mammal Protection Act (MMPA) as amended, notification is hereby given that NMFS has issued an incidental harassment authorization (IHA) to SouthCoast Wind Energy, LLC (SouthCoast Wind; formerly known as Mayflower Wind Energy, LLC) to incidentally harass marine mammals during marine site characterization surveys off Massachusetts and Rhode Island.

DATES: This Authorization is effective from May 12, 2023 through May 11, 2024.

FOR FURTHER INFORMATION CONTACT: Kelsey Potlock, Office of Protected Resources, NMFS, (301) 427–8401. Electronic copies of the original application and supporting documents (including NMFS **Federal Register** notices of the original proposed and final authorizations, and the previous IHA), as well as a list of the references cited in this document, may be obtained online at: <https://www.fisheries.noaa.gov/permit/incidental-take-authorizations-under-marine-mammal-protection-act>. In case of problems accessing these documents, please call the contact listed above.

SUPPLEMENTARY INFORMATION:

Background

The MMPA prohibits the “take” of marine mammals, with certain exceptions. Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce (as delegated to NMFS) to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are

issued or, if the taking is limited to harassment, a notice of a proposed incidental take authorization may be provided to the public for review.

Authorization for incidental takings shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s) and will not have an unmitigable adverse impact on the availability of the species or stock(s) for taking for subsistence uses (where relevant). Further, NMFS must prescribe the permissible methods of taking and other “means of effecting the least practicable adverse impact” on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of such species or stocks for taking for certain subsistence uses (referred to in shorthand as “mitigation”); and requirements pertaining to the mitigation, monitoring and reporting of such takings are set forth.

The definitions of all applicable MMPA statutory terms cited above are included in the relevant sections below.

Summary of Request

On October 23, 2020, NMFS received a request from SouthCoast Wind seeking authorization to take marine mammals incidental to high-resolution geophysical site characterization surveys (HRG) off Massachusetts and Rhode Island in the area of Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer Continental Shelf Lease Area OCS–A–0521. Within this request, the applicant had requested authorization to harass (by Level B harassment only) up to 14 species of marine mammals (comprising 13 cetacean species and 1 collective pinniped guild). NMFS published notice of the proposed IHA in the **Federal Register** on March 1, 2021 (86 FR 11930). Following publication of the proposed IHA notice, SouthCoast Wind adjusted the proposed survey routes and submitted a modified IHA application to NMFS on April 19, 2021. Based on this modified application, an updated notice of proposed IHA was published in the **Federal Register** on May 20, 2021 (86 FR 27393). NMFS subsequently issued an IHA that was effective for a period of 1 year, from July 1, 2021 through June 30, 2022 (86 FR 38033, July 19, 2021).

On November 16, 2022, SouthCoast Wind submitted an application for a renewal IHA in order to complete the remaining subset of the planned survey activity that could not be completed under the 2021 IHA. This request was for the take of small numbers of 15

² See Petitioner Letter, “Gas Powered Pressure Washers from the People’s Republic of China: Request for Postponement of the Preliminary Determination,” dated April 24, 2023.

³ *Id.*

species of marine mammals (comprising 13 cetacean and 2 pinniped species), by Level B harassment only. Given the availability of updated marine mammal density information from Duke University's Marine Geospatial Ecology Laboratory (<https://seamap.env.duke.edu/models/Duke/EC/>) on June 20, 2022, NMFS determined that an IHA renewal was not appropriate in this circumstance. However, because the activity would otherwise qualify for a renewal of the initial IHA, *i.e.*, the scope of the activities, the survey location, the acoustic source use, and the level of impact expected to occur (*i.e.*, Level B harassment only) remain the same, NMFS relies substantially herein on the information previously presented in notices associated with issuance of the initial IHA (86 FR 11930, March 1, 2021; 86 FR 27393, May 20, 2021; 86 FR 38033, July 19, 2021).

Following additional discussions with NMFS, SouthCoast Wind submitted an updated request for a standard IHA on January 13, 2023 rather than a renewal IHA. SouthCoast Wind's request covered the same activities (using the same sound sources), occurring in the same location, and the mitigation, monitoring, and reporting requirements are similar to those described in the **Federal Register** notice announcing the issuance of the 2021 IHA (86 FR 38033, July 19, 2021). The only changes are that the total number of survey days have been reduced, the number of vessels performing survey activities have been reduced, reduction in the assumed survey distance per day, and a reduction in total survey trackline as described in greater detail below. This updated request was deemed adequate and complete on January 24, 2023. No changes were made from the proposed to the final IHA.

Neither SouthCoast Wind, nor NMFS expect serious injury or mortality to result from this activity. Take by Level A harassment (injury) is considered unlikely, even absent mitigation, based on the characteristics of the signals produced by the acoustic sources planned for use.

Description of the Activity and Anticipated Impacts

Overview

SouthCoast Wind will conduct geotechnical and high-resolution geophysical (HRG) surveys in the Lease Area OCS-A-0521 and along potential submarine export cable routes (ECRs) to landfall locations in Falmouth, Massachusetts and Narragansett Bay, Rhode Island (refer back to Figure 1 in

88 FR 14335, March 8, 2023). The survey area is the same as that previously described in the application for the 2021 IHA (86 FR 27393, May 20, 2021; 86 FR 38033, July 19, 2021) and consists of approximately 127,388 acres (515.5 square kilometers (km²)) extending approximately 20 nautical miles (nmi, 38 kilometers (km)) offshore.

The purpose of these surveys are to acquire HRG and geotechnical data on the bathymetry, seafloor morphology, subsurface geology, environmental/biological sites, seafloor obstructions, soil conditions, and locations of any man-made, historical or archaeological resources within the Lease Area and along the ECR corridor. Three survey vessels may operate concurrently as part of the surveys, running at a maximum speed of 3 to 4 knots (3.5 to 4.6 miles per hour). Additionally, a shallow-water vessel may survey the nearshore areas of the project location, but this would only occur during daylight hours and for a maximum of 12-hours daily. Up to 114 days of surveys are planned, with vessels operating for 24-hours as part of the planned surveys (Table 1).

TABLE 1—NUMBER OF SURVEY DAYS THAT SOUTHCOST WIND WILL PERFORM THE DESCRIBED HRG SURVEY ACTIVITIES

Survey Location	Number of days of active acoustic source use
Lease Area	39
Export Cable Routes	75
Total Number of Days	114

Underwater sound resulting from SouthCoast Wind's site characterization survey activities has the potential to result in incidental take of marine mammals in the form of behavioral harassment (*i.e.*, Level B harassment), specifically during use of certain acoustic sources operating at <180 kilohertz (kHz). SouthCoast requested the issuance of an IHA authorizing the take, by Level B harassment only, of 15 species of marine mammals (comprising 15 stocks) incidental to marine site characterization surveys, specifically in association with the use of HRG survey equipment.

A detailed description of the planned surveys by SouthCoast Wind are provided in the **Federal Register** notice of the proposed IHA (88 FR 14335, March 8, 2023). Since that time, no changes have been made to the survey activities. Therefore, a detailed

description is not provided here. Please refer to that **Federal Register** notice for the description of the specified activities.

The mitigation, monitoring, and reporting measures are described in detail later in this document (please see Mitigation and Monitoring and Reporting).

Comments and Responses

A notice of NMFS' proposal to issue an IHA to SouthCoast Wind was published in the **Federal Register** on March 8, 2023 (88 FR 14335). That proposed notice described, in detail, SouthCoast Wind's proposed activities, the marine mammal species that may be affected by these activities, and the anticipated effects on marine mammals. In that notice, we requested public input on the request for authorization described therein, our analyses, the proposed authorization, and requested that interested persons submit relevant information, suggestions, and comments. This proposed notice was available for a 30-day public comment period.

NMFS received a comment letter from an environmental non-governmental organization (eNGO), Oceana, Inc. All comments, and NMFS' responses, are provided below, and the letter is available online on NMFS' website (<https://www.fisheries.noaa.gov/permit/incidental-take-authorizations-under-marine-mammal-protection-act>). Please review the comment letter for full details regarding the comments and associated rationale.

Comment 1: Oceana raised objections to NMFS' proposed renewal process for potential extension of the 1-year IHA with an abbreviated 15-day public comment period. Oceana recommended that an additional 30-day public comment period is necessary for any IHA renewal request.

Response: NMFS' IHA renewal process meets all statutory requirements. In prior responses to comments about IHA renewals (*e.g.*, 84 FR 52464, October 2, 2019 and 85 FR 53342, August 28, 2020), NMFS explained the IHA renewal process is consistent with the statutory requirements contained in section 101(a)(5)(D) of the MMPA, and further promotes NMFS' goals of improving conservation of marine mammals and increasing efficiency in the MMPA compliance process. Therefore, we intend to continue to implement the existing renewal process.

All IHAs issued, whether an initial IHA or a renewal, are valid for a period of not more than 1 year. The public has 30 days to comment on proposed IHAs,

with a cumulative total of 45 days for IHA renewals. The notice of the proposed IHA published in the **Federal Register** on March 8, 2023 (88 FR 14335) provided a 30-day public comment period and made clear that NMFS was seeking comment on the proposed IHA and the potential issuance of a renewal for this survey. As detailed in the **Federal Register** notice for the proposed IHA and on the agency's website, eligibility for renewal is determined on a case-by-case basis, renewals are subject to an additional 15-day public comment period, and the renewal is limited to up to another year of identical or nearly identical activities as described in the Description of Proposed Activities section of the proposed IHA notice or the activities described in the Description of Proposed Activities section of the proposed IHA notice would not be completed by the time the IHA expires and a renewal would allow for completion of the activities beyond that described in the Dates and Duration section of the proposed notice. NMFS' analysis of the anticipated impacts on marine mammals caused by the applicant's activities covers both the initial IHA period and the possibility of a 1-year renewal. Therefore, a member of the public considering commenting on a proposed initial IHA also knows exactly what activities (or subset of activities) would be included in a proposed renewal IHA, the potential impacts of those activities, the maximum amount and type of take that could be caused by those activities, the mitigation and monitoring measures that would be required, and the basis for the agency's negligible impact determinations, least practicable adverse impact findings, small numbers findings, and (if applicable) the no unmitigable adverse impact on subsistence use finding—all the information needed to provide complete and meaningful comments on a possible renewal at the time of considering the proposed initial IHA. Members of the public have the information needed to meaningfully comment on both the immediate proposed IHA and a possible 1-year renewal, should the IHA holder choose to request one.

While there would be additional documents submitted with a renewal request, for a qualifying renewal these would be limited to documentation that NMFS would make available and use to verify that the activities are identical or nearly identical to those in the initial IHA such that the changes would have either no effect on impacts to marine mammals or decrease those impacts, or

are a subset of activities already analyzed and authorized but not completed under the initial IHA. NMFS would also need to confirm, among other things, that the activities would occur in the same location; involve the same species and stocks; provide for continuation of the same mitigation, monitoring, and reporting requirements; and that no new information has been received that would alter the prior analysis. The renewal request would also contain a preliminary monitoring report, in order to verify that effects from the activities do not indicate impacts of a scale or nature not previously analyzed. The additional 15-day public comment period, which includes NMFS' direct notice to anyone who commented on the proposed initial IHA, provides the public an opportunity to review these few documents, provide any additional pertinent information, and comment on whether they think the criteria for a renewal have been met. Combined together, the 30-day public comment period on the initial IHA and the additional 15-day public comment period on the renewal of the same or nearly identical activities, provides the public with a total of 45 days to comment on the potential for renewal of the IHA.

In addition to the IHA renewal process being consistent with all requirements under section 101(a)(5)(D), it is also consistent with Congress' intent for issuance of IHAs to the extent reflected in statements in the legislative history of the MMPA. Through the description of the process and express invitation to comment on specific potential renewals in the Request for Public Comments section of each proposed IHA, the description of the process on NMFS' website, further elaboration on the process through responses to comments such as these, posting of substantive documents on the agency's website, and provision of 30 or 45 days for public review and comment on all proposed initial IHAs and renewals respectively, NMFS has ensured that the public is "invited and encouraged to participate fully in the agency's decision-making process," as Congress intended.

Comment 2: Oceana stated that NMFS must utilize the best available scientific evidence, and suggested that NMFS has not done so, specifically referencing information regarding the North Atlantic right whale (NARW) such as updated population estimates, habitat usage in the survey area, and seasonality information. Oceana specifically asserted that NMFS is not using the best available scientific evidence with

regards to the NARW population estimate.

Response: NMFS agrees the best available scientific evidence should be used for assessing NARW abundance estimates. Following the recent publication of NMFS' draft 2022 Stock Assessment Reports (SAR), NMFS updated the information relied upon herein accordingly. In prior responses to comments, NMFS has found that the SAR is the best available scientific evidence with respect to NARW population estimates (see e.g., 87 FR 25452). We find no reason to reconsider or depart from this.

Moreover, the draft 2022 SARs report the same NARW abundance estimate (336) cited by Oceana in its public comment. We further note that this change in abundance estimate does not change the estimated take of NARWs or authorized take numbers, nor does it affect our ability to make the required findings under the MMPA for SouthCoast Wind's survey activities.

In sum, NMFS considered the best available scientific evidence regarding both recent habitat usage patterns for the study area and up-to-date seasonality information in the notice of the proposed IHA, including consideration of existing biologically important areas (BIAs) and densities provided by Roberts and Halpin (2022). While the commenter has suggested that NMFS consider best available scientific evidence for recent habitat usage patterns and seasonality, the commenter has not offered any additional scientific information that it suggests should be considered best available scientific evidence.

Comment 3: Oceana noted that chronic stressors are an emerging concern for NARW conservation and recovery, and stated that chronic stress may result in energetic effects for NARWs. Oceana suggested that NMFS has not fully considered both the use of the area and the effects of both acute and chronic stressors on the health and fitness of NARWs, as disturbance responses in NARWs could lead to chronic stress or habitat displacement, leading to an overall decline in their health and fitness.

Response: NMFS agrees with Oceana that both acute and chronic stressors are of concern for NARW conservation and recovery. We recognize that acute stress from acoustic exposure is one potential impact of these surveys, and that chronic stress can have fitness, reproductive, etc. impacts at the population-level scale. NMFS has carefully reviewed the best available scientific information in assessing impacts to marine mammals, and

recognizes that the surveys have the potential to impact marine mammals through behavioral effects, stress responses, and auditory masking. However, NMFS does not expect that the generally short-term, intermittent, and transitory marine site characterization survey activities planned by SouthCoast Wind will create conditions of acute or chronic acoustic exposure leading to long-term physiological stress responses in marine mammals. NMFS has prescribed a robust suite of mitigation measures, including extended distance shutdowns for NARW, that are expected to further reduce the duration and intensity of acoustic exposure, while limiting the potential severity of any possible behavioral disruption. The potential for chronic stress was evaluated in making the determinations presented in NMFS' negligible impact analyses.

SouthCoast Wind's survey area is near a known NARW foraging location in the New England region, as well as overlapping a small fraction of the migratory corridor used by NARW in a transitory manner for annual migratory activities. Given that the potential impacts for these types of surveys are expected to be low level, in part as a result of the brief periods where harassment-level noise exposure may be possible, we do not expect chronic effects to occur as a result of SouthCoast Wind's surveys. Furthermore, the limited range to the estimated harassment zone of the largest acoustic source (141 m) and the survey path within and near the SouthCoast Wind lease means that the area where NARWs are known to concentrate within Nantucket Shoals would not be impacted. Because of this, we do not expect effects to include reduced foraging opportunities for NARWs. Because of these reasons, NMFS does not expect acute or cumulative stress to be a detrimental factor to NARWs from SouthCoast Wind's described survey activities.

Lastly, NMFS does not find that the effects of SouthCoast Wind's survey may contribute to stunted growth rates as suggested by Oceana's comments. The activities associated with SouthCoast Wind's survey are outside the scope of activities described in the Stewart *et al.* (2021) paper, which finds that entanglements in fishing gear are associated with shorter whales. There is no evidence suggesting that the survey activities considered herein could have energetic effects similar to those caused by entanglement in fishing gear. Therefore, NMFS does not expect stunted growth rates to result from

SouthCoast Wind's described survey activities.

Comment 4: Oceana asserted that NMFS must fully consider the discrete effects of each activity and the cumulative effects of the suite of approved, proposed and potential activities on marine mammals and North Atlantic right whales in particular and ensure that the cumulative effects are not excessive before issuing or renewing an IHA.

Response: Neither the MMPA nor NMFS' codified implementing regulations call for consideration of other unrelated activities and their impacts on populations. The preamble for NMFS' implementing regulations (54 FR 40338, September 29, 1989) states in response to comments that the impacts from other past and ongoing anthropogenic activities are to be incorporated into the negligible impact analysis via their impacts on the baseline. Consistent with that direction, NMFS has factored into its negligible impact analysis the impacts of other past and ongoing anthropogenic activities via their impacts on the baseline, *e.g.*, as reflected in the density/distribution and status of the species, population size and growth rate, and other relevant stressors. The 1989 final rule for the MMPA implementing regulations also addressed public comments regarding cumulative effects from future, unrelated activities. There NMFS stated that such effects are not considered in making findings under section 101(a)(5) concerning negligible impact. In this case, this IHA, as well as other IHAs currently in effect or proposed within the specified geographic region, are appropriately considered an unrelated activity relative to the others. The IHAs are unrelated in the sense that they are discrete actions under section 101(a)(5)(D), issued to discrete applicants.

Section 101(a)(5)(D) of the MMPA requires NMFS to make a determination that the take incidental to a "specified activity" will have a negligible impact on the affected species or stocks of marine mammals. NMFS' implementing regulations require applicants to include in their request a detailed description of the specified activity or class of activities that can be expected to result in incidental taking of marine mammals (50 CFR 216.104(a)(1)). Thus, the "specified activity" for which incidental take coverage is being sought under section 101(a)(5)(D) is generally defined and described by the applicant. Here, SouthCoast Wind was the applicant for the IHA, and we are responding to the specified activity as described in that

application (and making the necessary findings on that basis).

Through the response to public comments in the 1989 implementing regulations (54 FR 40338; September 29, 1989), NMFS also indicated (1) that we would consider cumulative effects that are reasonably foreseeable when preparing a National Environmental Protection Act (NEPA) analysis, and (2) that reasonably foreseeable cumulative effects would also be considered under section 7 of the Endangered Species Act (ESA) for listed species, as appropriate. Accordingly, NMFS has written an Environmental Assessments (EA) that addressed cumulative impacts related to substantially similar activities, in similar locations, *e.g.*, the 2019 Avangrid EA for survey activities offshore North Carolina and Virginia; the 2017 Ocean Wind, LLC EA for site characterization surveys off New Jersey; and the 2018 Deepwater Wind EA for survey activities offshore Delaware, Massachusetts, and Rhode Island. Cumulative impacts regarding issuance of IHAs for site characterization survey activities, such as those planned by SouthCoast Wind, have been adequately addressed under NEPA in prior environmental analyses that support NMFS' determination that this action is appropriately categorically excluded from further NEPA analysis. NMFS independently evaluated the use of a categorical exclusion (CE) for issuance of SouthCoast Wind's IHA, which included consideration of extraordinary circumstances.

Separately, the cumulative effects of substantially similar activities in the northwest Atlantic Ocean have been analyzed in the past under section 7 of the ESA when NMFS has engaged in formal intra-agency consultation, such as the 2013 programmatic Biological Opinion (BiOp) for BOEM Lease and Site Assessment Rhode Island, Massachusetts, New York, and New Jersey Wind Energy Areas (<https://repository.library.noaa.gov/view/noaa/29291>). Analyzed activities include those for which NMFS issued previous IHAs (82 FR 31562, July 7, 2017; 85 FR 21198, April 16, 2020; 86 FR 26465, May 10, 2021), which are similar to those planned by SouthCoast Wind under this current IHA request. This Biological Opinion determined that NMFS' issuance of IHAs for site characterization survey activities associated with leasing, individually and cumulatively, are not likely to adversely affect listed marine mammals. NMFS notes that, while issuance of this IHA is covered under a different consultation, this BiOp remains valid.

Comment 5: Oceana states that NMFS must make an assessment of which activities, technologies, and strategies are truly necessary to achieve site characterization to inform development of the offshore wind projects and which are not critical, asserting that NMFS should prescribe the appropriate survey techniques. In general, Oceana stated that NMFS must require that all IHA applicants minimize the impacts of underwater noise to the fullest extent feasible, including through the use of best available technology and methods to minimize sound levels from geophysical surveys such as through the use of technically and commercially feasible and effective noise reduction and attenuation measures.

Response: The MMPA requires that an IHA include measures that will effect the least practicable adverse impact on the affected species and stocks and, in practice, NMFS agrees that the IHA should include conditions for the survey activities that will first avoid adverse effects on North Atlantic right whales in and around the survey site, where practicable, and then minimize the effects that cannot be avoided. NMFS has determined that the IHA meets this requirement to effect the least practicable adverse impact. As part of the analysis for all marine site characterization survey IHAs, NMFS evaluated the effects expected as a result of the specified activity, made the necessary findings, and prescribed mitigation requirements sufficient to achieve the least practicable adverse impact on the affected species and stocks of marine mammals. It is not within NMFS' purview to make judgments regarding what may be appropriate techniques or technologies for an operator's survey objectives.

Comment 6: Oceana states that SouthCoast Wind's activities will increase vessel traffic in and around the project area and that the IHA must include a vessel traffic plan to minimize the effects of increased vessel traffic.

Response: NMFS disagrees with Oceana's statement that the IHA must require a vessel traffic plan. During HRG surveys, there are no service vessels required. NMFS agrees that a vessel plan may be potentially appropriate for project construction, but it is not needed for marine site characterization surveys.

Comment 7: Oceana suggests that Protected Species Observers (PSOs) complement their survey efforts using additional technologies, such as infrared detection devices when in low-light conditions.

Response: NMFS agrees with Oceana regarding this suggestion and a requirement to utilize a thermal

(infrared) device during low-light conditions was included in the proposed **Federal Register** notice. That requirement is included as a requirement of the issued IHA.

Comment 8: Oceana recommended that NMFS restrict all vessels of all sizes associated with the proposed survey activities to speeds less than 10 knots (kn) at all times due to the risk of vessel strikes to North Atlantic right whales and other large whales.

Response: While NMFS acknowledges that vessel strikes can result in injury or mortality, we have analyzed the potential for vessel strike resulting from SouthCoast Wind's activity and have determined that based on the nature of the activity and the required mitigation measures specific to vessel strike avoidance included in the IHA, potential for vessel strike is so low as to be discountable. The required mitigation measures, all of which were included in the proposed IHA and are now required in the final IHA, include: A requirement that all vessel operators comply with 10 kn (18.5 km/hour) or less speed restrictions in any seasonal management area (SMA), dynamic management area (DMA), or Slow Zone while underway, and check daily for information regarding the establishment of mandatory or voluntary vessel strike avoidance areas (SMAs, DMAs, Slow Zones) and information regarding NARW sighting locations; a requirement that all vessels greater than or equal to 19.8 m in overall length operating from November 1 through April 30 operate at speeds of 10 kn (18.5 km/hour) or less; a requirement that all vessel operators reduce vessel speed to 10 kn (18.5 km/hour) or less when any large whale, any mother/calf pairs, pods, or large assemblages of non-delphinid cetaceans are observed near the vessel; a requirement that all survey vessels maintain a separation distance of 500 m or greater from North Atlantic right whales (100 m from any ESA-listed whales) or other unidentified large marine mammals visible at the surface while underway; a requirement that, if underway, vessels must steer a course away from any sighted ESA-listed whale at 10 kn or less until the 100 m minimum separation distance (or 500 m distance for North Atlantic right whales) has been established; a requirement that, if an ESA-listed whale is sighted in a vessel's path, or within 100 m of an underway vessel (500 m for a North Atlantic right whale), the underway vessel must reduce speed and shift the engine to neutral; and, a requirement that all vessels underway must maintain a minimum separation distance of 100 m from all other marine mammals

(excluding North Atlantic right whales), with an understanding that at times this may not be possible (e.g., for animals that approach the vessel). We have determined that the vessel strike avoidance measures in the IHA are sufficient to ensure the least practicable adverse impact on species or stocks and their habitat. Furthermore, no documented vessel strikes have occurred for any marine site characterization surveys which were issued IHAs from NMFS during the survey activities themselves or while transiting to and from survey sites.

Comment 9: Oceana suggests that NMFS require vessels maintain a separation distance of at least 500 m from North Atlantic right whales at all times.

Response: NMFS agrees with Oceana regarding this suggestion and a requirement to maintain a separation distance of at least 500 m from North Atlantic right whales at all times was included in the proposed **Federal Register** notice and was included as a requirement in the issued IHA.

Comment 10: Oceana recommended that the IHA should require all vessels supporting site characterization to be equipped with and use Class A Automatic Identification System (AIS) devices at all times while on the water. Oceana suggested this requirement should apply to all vessels, regardless of size, associated with the survey.

Response: NMFS is generally supportive of the idea that vessels involved with survey activities be equipped with and use Class A AIS devices at all times while on the water. Indeed, there is a precedent for NMFS requiring such a stipulation for geophysical surveys in the Atlantic Ocean (83 FR 63268, December 7, 2018); however, these seismic surveys carried the potential for much more significant impacts than the marine site characterization surveys planned by SouthCoast Wind. Given the comparatively small footprint of potential effects and correspondingly low level of concern regarding HRG survey activities, NMFS has determined that the operational costs associated with a requirement to so equip vessels not otherwise required to carry AIS are not warranted under the MMPA's least practicable adverse impact standard.

Comment 11: Oceana asserts that the IHA must include requirements to hold all vessels associated with site characterization surveys accountable to the IHA requirements, including vessels owned by the developer, contractors, employees, and others regardless of ownership, operator, and contract. They state that exceptions and exemptions

will create enforcement uncertainty and incentives to evade regulations through reclassification and redesignation. They recommend that NMFS simplify this by requiring all vessels to abide by the same requirements, regardless of size, ownership, function, contract, or other specifics.

Response: NMFS agrees with Oceana and the proposed IHA and final IHA has general conditions to hold SouthCoast Wind and its designees (including vessel operators and other personnel) accountable while performing operations under the authority of the IHA. The plain language of the IHA indicates that the conditions contained therein apply to SouthCoast Wind and its designees. The IHA requires that a copy of the IHA must be in the possession of SouthCoast Wind, the vessel operators, the lead PSO, and any other relevant designees of SouthCoast Wind operating under the authority of this IHA. The IHA also states that SouthCoast Wind must ensure that the vessel operator and other relevant vessel personnel, including the PSO team, are briefed on all responsibilities, communication procedures, marine mammal monitoring protocols, operational procedures, and IHA requirements prior to the start of survey activity, and when relevant new personnel join the survey operations.

Comment 12: Oceana stated that the IHA must include a requirement for all phases of the site characterization to subscribe to the highest level of transparency, including frequent reporting to Federal agencies. Oceana recommends requirements to report all visual and acoustic detections of North Atlantic right whales and any dead, injured, or entangled marine mammals to NMFS or the Coast Guard as soon as possible and no later than the end of the PSO shift. Oceana states that to foster stakeholder relationships and allow public engagement and oversight of the permitting, the IHA should require all reports and data to be accessible on a publicly available website.

Response: NMFS agrees with the need for reporting and, indeed, the MMPA calls for IHAs to incorporate reporting requirements. As included in the proposed IHA, the final IHA includes requirements for reporting that supports Oceana's recommendations. SouthCoast Wind is required to submit a monitoring report to NMFS within 90 days after completion of survey activities that fully documents the methods and monitoring protocols, summarizes the data recorded during monitoring. PSO datasheets or raw sightings data must also be provided with the draft and final monitoring report.

Further, the draft IHA and final IHA stipulate that if a North Atlantic right whale is observed at any time by any survey vessels, during surveys or during vessel transit, SouthCoast Wind must immediately report sighting information to the NMFS North Atlantic Right Whale Sighting Advisory System within 2 hours of occurrence, when practicable, or no later than 24 hours after occurrence. SouthCoast Wind may also report the sighting to the U.S. Coast Guard. Additionally, SouthCoast Wind must report any discoveries of injured or dead marine mammals to the Office of Protected Resources, NMFS, and to the New England/Mid-Atlantic Regional Stranding Coordinator as soon as feasible. This includes entangled animals. All reports and associated data submitted to NMFS are included on the website for public inspection.

Daily visual and acoustic detections of North Atlantic right whales and other large whale species along the Eastern Seaboard, as well as Slow Zone locations, are publicly available on WhaleMap (<https://whalemap.org/WhaleMap/>). Further, recent acoustic detections of North Atlantic right whales and other large whale species are available to the public on NOAA's Passive Acoustic Cetacean Map website <https://apps-nefsc.fisheries.noaa.gov/pacm/#/narw>. Given the open access to the resources described above, NMFS does not concur that public access to quarterly PSO reports is warranted and we have not included this measure in the authorization.

Comment 13: Oceana recommended increasing the Exclusion Zone to 1,000 m for North Atlantic right whales with requirements for HRG survey vessels to use PSOs and Passive Acoustic Monitoring (PAM) to establish and monitor these zones.

Response: NMFS notes that the 500 m Exclusion Zone for North Atlantic right whales exceeds the modeled distance to the largest 160 dB Level B harassment isopleth (141 m during sparker use) by a conservative margin to be extra cautious. Commenters do not provide a compelling rationale for why the Exclusion Zone should be even larger. Given that these surveys are relatively low impact and that, regardless, NMFS has prescribed a precautionary North Atlantic right whale Exclusion Zone that is larger (500 m) than the conservatively estimated largest harassment zone (141 m), NMFS has determined that the Exclusion Zone is appropriate.

Regarding the use of acoustic monitoring to implement the exclusion zones, NMFS does not anticipate that acoustic monitoring would be effective

for a variety of reasons discussed below and therefore has not required it in this IHA. As described in the mitigation section, NMFS has determined that the prescribed mitigation requirements are sufficient to effect the least practicable adverse impact on all affected species or stocks.

The commenters do not explain why they expect that PAM would be effective in detecting vocalizing mysticetes, nor does NMFS agree that this measure is warranted, as it is not expected to be effective for use in detecting the species of concern. It is generally accepted that, even in the absence of additional acoustic sources, using a towed passive acoustic sensor to detect baleen whales (including North Atlantic right whales) is not typically effective because the noise from the vessel, the flow noise, and the cable noise are in the same frequency band and will mask the vast majority of baleen whale calls. Vessels produce low-frequency noise, primarily through propeller cavitation, with main energy in the 5–300 hertz (Hz) frequency range. Source levels range from about 140 to 195 decibel (dB) re 1 μ Pa (micropascal) at 1 m (NRC, 2003; Hildebrand, 2009), depending on factors such as ship type, load, and speed, and ship hull and propeller design. Studies of vessel noise show that it appears to increase background noise levels in the 71–224 Hz range by 10–13 dB (Hatch *et al.*, 2012; McKenna *et al.*, 2012; Rolland *et al.*, 2012). PAM systems employ hydrophones towed in streamer cables approximately 500 m behind a vessel. Noise from water flow around the cables and from strumming of the cables themselves is also low frequency and typically masks signals in the same range. Experienced PAM operators participating in a recent workshop (Thode *et al.*, 2017) emphasized that a PAM operation could easily report no acoustic encounters, depending on species present, simply because background noise levels rendered any acoustic detection impossible. The same workshop report stated that a typical eight-element array towed 500 m behind a vessel could be expected to detect delphinids, sperm whales, and beaked whales at the required range, but not baleen whales, due to expected background noise levels (including seismic noise, vessel noise, and flow noise).

There are several additional reasons why we do not agree that use of PAM is warranted for 24-hour HRG surveys. While NMFS agrees that PAM can be an important tool for augmenting detection capabilities in certain circumstances, its utility in further reducing impact during HRG survey activities is limited. First,

for this activity, the area expected to be ensonified above the Level B harassment threshold is relatively small (a maximum of 141 m); this reflects the fact that, to start with, the source level is comparatively low and the intensity of any resulting impacts would be lower level and, further, it means that inasmuch as PAM will only detect a portion of any animals exposed within a zone, the overall probability of PAM detecting an animal in the harassment zone is low. Together these factors support the limited value of PAM for use in reducing take with smaller zones. PAM is only capable of detecting animals that are actively vocalizing and, many marine mammal species vocalize infrequently or during certain activities, which means that only a subset of the animals within the range of the PAM would be detected (and potentially have reduced impacts). Additionally, localization and range detection can be challenging under certain scenarios. For example, odontocetes are fast moving and often travel in large or dispersed groups which makes localization difficult.

Given that the effects to marine mammals from the types of surveys authorized in this IHA are expected to be limited to low level behavioral harassment even in the absence of mitigation, the limited additional benefit anticipated by adding this detection method (especially for North Atlantic right whales and other low frequency cetaceans, species for which PAM has limited efficacy), and the cost and impracticability of implementing a full-time PAM program, we have determined the current requirements for visual monitoring are sufficient to ensure the least practicable adverse impact on the affected species or stocks and their habitat. NMFS has previously provided discussions on why PAM isn't a required monitoring measure during

HRG survey IHAs in past **Federal Register** notices (see 86 FR 21289, April 22, 2021 and 87 FR 13975, March 11, 2022 for examples).

Comment 14: Oceana recommended that when HRG surveys are allowed to resume after a shutdown event, the surveys should be required to use a ramp-up procedure to encourage any nearby marine life to leave the area.

Response: NMFS agrees with this recommendation and included in the **Federal Register** notice of the proposed IHA (88 FR 14335, March 8, 2023) and this final IHA a stipulation that when technically feasible, survey equipment must be ramped up at the start or restart of survey activities. Ramp-up must begin with the power of the smallest acoustic equipment at its lowest practical power output appropriate for the survey. When technically feasible the power must then be gradually turned up and other acoustic sources added in a way such that the source level would increase gradually. NMFS notes that ramp-up would not be required for short periods where acoustic sources were shut down (*i.e.*, less than 30 minutes) if PSOs have maintained constant visual observation and no detections of marine mammals occurred within the applicable Exclusion Zones.

Description of Marine Mammals in the Area of Specified Activities

Sections 3 and 4 of the application summarize available information regarding status and trends, distribution and habitat preferences, and behavior and life history, of the potentially affected species. Additional information regarding population trends and threats may be found in NMFS's Stock Assessment Reports (SARs; <https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments>) and more

general information about these species (*e.g.*, physical and behavioral descriptions) may be found on NMFS's website (<https://www.fisheries.noaa.gov/find-species>).

Table 2 lists all species or stocks for which take is authorized for this action, and summarizes information related to the population or stock, including regulatory status under the MMPA and Endangered Species Act (ESA) and potential biological removal (PBR), where known. PBR is defined by the MMPA as the maximum number of animals, not including natural mortalities, that may be removed from a marine mammal stock while allowing that stock to reach or maintain its optimum sustainable population (as described in NMFS's SARs). While no mortality is anticipated or authorized here, PBR and annual serious injury and mortality from anthropogenic sources are included here as gross indicators of the status of the species and other threats.

Marine mammal abundance estimates presented in this document represent the total number of individuals that make up a given stock or the total number estimated within a particular study or survey area. NMFS's stock abundance estimates for most species represent the total estimate of individuals within the geographic area, if known, that comprises that stock. For some species, this geographic area may extend beyond U.S. waters. All managed stocks in this region are assessed in NMFS' U.S. Atlantic and Gulf of Mexico Marine Mammal Stock Assessment. All values presented in Table 2 are the most recent available at the time of publication, including from the draft 2022 SARs, and are available online at: <https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments>.

TABLE 2—MARINE MAMMALS LIKELY TO OCCUR IN THE PROJECT AREA THAT MAY BE AFFECTED BY SOUTHCOAST WIND'S ACTIVITY

Common name	Scientific name	Stock	ESA/ MMPA status; strategic (Y/N) ¹	Stock abundance (CV, N _{min} , most recent abun- dant survey) ²	PBR ³	Annual M/SI ³
Order Artiodactyla—Cetacea—Mysticeti (baleen whales)						
<i>Family Balaenidae:</i> North Atlantic Right Whale	<i>Eubalaena glacialis</i>	Western North Atlantic	E, D, Y	338 (0, 332, 2020)	0.7	8.1
<i>Family Balaenopteridae</i> (<i>rorquals</i>):						
Fin Whale	<i>Balaenoptera physalus</i>	Western North Atlantic	E, D, Y	6,802 (0.24; 5,573; 2016)	11	1.8
Humpback Whale	<i>Megaptera novaeangliae</i>	Gulf of Maine	- , -, Y	1,396 (0; 1,380; 2016)	22	12.15
Minke Whale	<i>Balaenoptera acutorostrata</i>	Canadian Eastern Coastal	- , -, N	21,968 (0.31; 17,002; 2016) ..	170	10.6
Sei Whale	<i>Balaenoptera borealis</i>	Nova Scotia	E, D, Y	6,292 (1.02; 3,098; 2016)	6.2	0.8
Odontoceti (toothed whales, dolphins, and porpoises)						
<i>Family Physteridae:</i>						

TABLE 2—MARINE MAMMALS LIKELY TO OCCUR IN THE PROJECT AREA THAT MAY BE AFFECTED BY SOUTHCOAST WIND'S ACTIVITY—Continued

Common name	Scientific name	Stock	ESA/ MMPA status; strategic (Y/N) ¹	Stock abundance (CV, N _{min} , most recent abun- dant survey) ²	PBR ³	Annual M/SI ³
Sperm Whale	<i>Physeter macrocephalus</i>	North Atlantic	E, D, Y	4,349 (0.28; 3451; 2016)	3.9	0
Family Delphinidae:						
Atlantic Spotted Dolphin ..	<i>Stenella frontalis</i>	Western North Atlantic	- , - , N	39,921 (0.27; 32,032; 2016) ..	320	0
Atlantic White-Sided Dol- phin.	<i>Lagenorhynchus acutus</i>	Western North Atlantic	- , - , N	93,233 (0.71; 54,443; 2016) ..	544	27
Bottlenose Dolphin	<i>Tursiops truncatus</i>	Western North Atlantic—Off- shore.	- , - , N	62,851 b (0.23; 51,914; 2016)	519	28
Long-Finned Pilot Whale ..	<i>Globicephala melas</i>	Western North Atlantic	- , - , N	39,215 (0.3; 30,627; 2016)	306	29
Risso's Dolphin	<i>Grampus griseus</i>	Western North Atlantic	- , - , N	35,215 (0.19; 30,051; 2016) ..	301	34
Common Dolphin	<i>Delphinus delphis</i>	Western North Atlantic	- , - , N	172,947 (0.21; 145,216; 2016)	1452	390
Family Phocoenidae (por- poises):						
Harbor Porpoise	<i>Phocoena phocoena</i>	Gulf of Maine/Bay of Fundy ...	- , - , N	95,543 (0.31; 74,034; 2016) ..	851	164
Order Carnivora—Pinnipedia						
Family Phocidae (earless seals):						
Gray Seal ⁴	<i>Halichoerus grypus</i>	Western North Atlantic	- , - , N	27,300 (0.22; 22,785; 2016) ..	1389	4453
Harbor Seal	<i>Phoca vitulina</i>	Western North Atlantic	- , - , N	61,336 (0.08; 57,637; 2018) ..	1729	339

¹ ESA status: Endangered (E), Threatened (T)/MMPA status: Depleted (D). A dash (-) indicates that the species is not listed under the ESA or designated as depleted under the MMPA. Under the MMPA, a strategic stock is one for which the level of direct human-caused mortality exceeds PBR or which is determined to be declining and likely to be listed under the ESA within the foreseeable future. Any species listed under the ESA is automatically designated under the MMPA as depleted and as a strategic stock.

² NMFS marine mammal stock assessment reports online at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments. CV is the coefficient of variation; N_{min} is the minimum estimate of stock abundance. In some cases, CV is not applicable.

³ These values, found in NMFS' SARs, represent annual levels of human-caused mortality plus serious injury from all sources combined (e.g., commercial fisheries, ship strike).

⁴ NMFS' gray seal stock abundance estimate (and associated PBR value) applies to U.S. population only. Total stock abundance (including animals in Canada) is approximately 450,000. The annual mortality and serious injury (M/SI) value given is for the total stock.

A detailed description of the species likely to be affected by SouthCoast Wind's activities, including information regarding population trends and threats, and local occurrence, were provided in the **Federal Register** notice for the proposed IHA (88 FR 14335; March 8, 2023). Since that time, we are not aware of any changes in the status of these species and stocks or other relevant new information; therefore, detailed descriptions are not provided here. Please refer to that **Federal Register** notice for those descriptions. Please also refer to NMFS's website (<https://www.fisheries.noaa.gov/find-species>) for generalized species accounts.

Marine Mammal Hearing

Hearing is the most important sensory modality for marine mammals

underwater, and exposure to anthropogenic sound can have deleterious effects. To appropriately assess the potential effects of exposure to sound, it is necessary to understand the frequency ranges marine mammals are able to hear. Current data indicate that not all marine mammal species have equal hearing capabilities (e.g., Richardson *et al.*, 1995; Wartzok and Ketten, 1999; Au and Hastings, 2008). To reflect this, Southall *et al.* (2007) recommended that marine mammals be divided into functional hearing groups based on directly measured or estimated hearing ranges on the basis of available behavioral response data, audiograms derived using auditory evoked potential techniques, anatomical modeling, and other data. Note that no direct

measurements of hearing ability have been successfully completed for mysticetes (*i.e.*, low-frequency cetaceans). Subsequently, NMFS (2018) described generalized hearing ranges for these marine mammal hearing groups. Generalized hearing ranges were chosen based on the approximately 65 decibel (dB) threshold from the normalized composite audiograms, with the exception for lower limits for low-frequency cetaceans where the lower bound was deemed to be biologically implausible and the lower bound from Southall *et al.* (2007) retained. Marine mammal hearing groups and their associated hearing ranges are provided in Table 3.

TABLE 3—MARINE MAMMAL HEARING GROUPS
[NMFS, 2018]

Hearing group	Generalized hearing range *
Low-frequency (LF) cetaceans (baleen whales)	7 Hz to 35 kHz.
Mid-frequency (MF) cetaceans (dolphins, toothed whales, beaked whales, bottlenose whales)	150 Hz to 160 kHz.
High-frequency (HF) cetaceans (true porpoises, <i>Kogia</i> , river dolphins, cephalorhynchid, <i>Lagenorhynchus cruciger</i> & <i>L. australis</i>).	275 Hz to 160 kHz.
Phocid pinnipeds (PW) (underwater) (true seals)	50 Hz to 86 kHz.
Otariid pinnipeds (OW) (underwater) (sea lions and fur seals)	60 Hz to 39 kHz.

* Represents the generalized hearing range for the entire group as a composite (*i.e.*, all species within the group), where individual species' hearing ranges are typically not as broad. Generalized hearing range chosen based on ~65 dB threshold from normalized composite audiogram, with the exception for lower limits for LF cetaceans (Southall *et al.*, 2007) and PW pinniped (approximation).

The pinniped functional hearing group was modified from Southall *et al.* (2007) on the basis of data indicating that phocid species have consistently demonstrated an extended frequency range of hearing compared to otariids, especially in the higher frequency range (Hemilä *et al.*, 2006; Kastelein *et al.*, 2009; Reichmuth, 2013). For more detail concerning these groups and associated frequency ranges, please see NMFS (2018) for a review of available information.

Potential Effects of Specified Activities on Marine Mammals and Their Habitat

The effects of underwater noise from the deployed acoustic sources have the potential to result in behavioral harassment of marine mammals in the vicinity of the study area. The **Federal Register** notice for the proposed IHA (88 FR 14335, March 8, 2023) referenced the previous **Federal Register** notices (86 FR 11930, March 1, 2021; 86 FR 27393, May 20, 2021; 86 FR 38033, July 19, 2021) for a discussion of the effects of anthropogenic noise, ship strike, stress, and potential impacts on marine mammals and their habitat. Therefore that information is not repeated here; please refer to those **Federal Register** notices for that information.

Estimated Take

A detailed description of the acoustic sources planned for use and the methods used to estimate take anticipated to occur incidental to the project is found in the previous **Federal Register** notices (86 FR 11930, March 1, 2021; 86 FR 27393, May 20, 2021; 86 FR 38033, July 19, 2021). The acoustic sources that may result in take, as well as the associated source levels, estimated isopleth distances to the 160 dB Level B harassment threshold (maximum of 141 m), resulting estimated ensonified areas, and the methods of take estimation, including the use of group size adjustments and Protected Species Observer (PSO) data, remain applicable to this final notice and are unchanged from those described for the 2021 IHA. Therefore, this information is not repeated here and we refer the reader to the previous **Federal Register** notices for detailed descriptions (86 FR 27393, May 20, 2021; 86 FR 38033, July 19, 2021). The only exception to this is the incorporation of newly updated density information (Roberts *et al.*, 2016; Roberts and Halpin, 2022), available online at: <https://seamap.env.duke.edu/>. We refer the reader to Tables 1 and 2

in the ITA Request from SouthCoast Wind for specific density values used in the analysis, as found on our website (<https://www.fisheries.noaa.gov/national/marine-mammal-protection/incidental-take-authorizations-other-energy-activities-renewable>).

The authorized take can be found below in Table 4. Table 4 presents the results of SouthCoast's density-based calculations, estimated potential take numbers based on observational data presented in region-specific PSO reports, and mean group sizes from both NMFS' Atlantic Marine Assessment Program for Protected Species (AMAPPS) survey data and references presented by SouthCoast in its application. The largest value for each species, across these sources, was authorized. For comparative purposes, we have provided the take that was previously authorized in the 2021 IHA (86 FR 38033, July 19, 2021). NMFS notes that take by Level A harassment was not requested, nor does NMFS anticipate that it could occur. Therefore, NMFS has not authorized any take by Level A harassment. No mortality or serious injury is anticipated to occur or authorized.

TABLE 4—TOTAL AUTHORIZED TAKES, BY LEVEL B HARASSMENT ONLY, RELATIVE TO POPULATION SIZE FOR SOUTHCOAST WIND'S 2023 HRG SURVEYS

Marine mammal species	Scientific name	Stock	Estimated population	Total density-based calculated take	PSO data take estimate	Mean group size		Take authorized under previous 2021 IHA	Final 2023 IHA	
						SouthCoast wind	AMAPPS		Authorized takes	Percentage of stock abundance
Mysticetes										
Fin Whale	<i>Balaenoptera physalus</i>	Western North Atlantic	6,802	3.0	6.5	1.8	1.25	6	7	0.1
Humpback Whale	<i>Megaptera novaeangliae</i>	Gulf of Maine	1,396	2.3	55.3	2.0	1.6	33	55	3.94
Minke Whale	<i>Balaenoptera acutorostrata</i>	Canadian Eastern Coastal	21,968	12.9	12.1	1.2	1.12	14	13	0.06
North Atlantic Right Whale	<i>Eubalaena glacialis</i>	Western North Atlantic	338	5.5	0.2	2.4	1.58	9	6	1.78
Sei Whale	<i>Balaenoptera borealis</i>	Nova Scotia	6,292	1.3	1.0	1.6	1.21	6	2	0.03
Odontocetes										
Atlantic Spotted Dolphin	<i>Stenella frontalis</i>	Western North Atlantic	39,921	3.5		29	24.2	^a n/a	29	0.07
Atlantic White-sided Dolphin	<i>Lagenorhynchus acutus</i>	Western North Atlantic	93,233	24.4		27.9	12.2	57	28	0.03
Bottlenose Dolphin	<i>Tursiops truncatus</i>	Western North Atlantic—Off-shore.	62,851	12.8	151.9	7.8	9.9	536	152	0.24
Common Dolphin	<i>Delphinus delphis</i>	Western North Atlantic	172,947	198.8	2,093.7	34.9	30.2	1,969	2,094	1.21
Harbor Porpoise	<i>Phocoena phocoena</i>	Gulf of Maine/Bay of Fundy	95,543	83.2	0.2	2.7	2.5	46	83	0.09
Long-finned Pilot Whale	<i>Globicephala melas</i>	Western North Atlantic	39,215	1.7	4.4	8.4	8.2	27	8	0.02
Risso's Dolphin	<i>Grampus griseus</i>	Western North Atlantic	35,215	2.0		5.4	7.3	18	7	0.01
Sperm Whale	<i>Physeter macrocephalus</i>	N Atlantic	4,349	0.9	0.3	1.5	1.7	6	2	0.04
Pinnipeds										
Harbor Seal	<i>Phoca vitulina</i>	Western North Atlantic	61,336	74.2	2.3	1.4	^c n/a	^b n/a	74	0.12
Gray Seal	<i>Halichoerus grypus</i>	Western North Atlantic	^d 27,300	166.7	38.7	1.4	^c n/a	^b n/a	167	^d 0.04

^a No takes for this species were authorized in the 2021 IHA (86 FR 38033, July 19, 2021).^b In the 2021 IHA (86 FR 38033, July 19, 2021), both seal species were combined into a single guild of 718 total authorized takes.^c No AMAPPS data was available for seals.^d NMFS' stock abundance estimate (and associated PBR value) applies to U.S. population only. Total stock abundance (including animals in Canada) is approximately 451,600. This value was used in the percentage of stock abundance estimated to be taken by the project.

Mitigation, Monitoring and Reporting Measures

The required mitigation, monitoring, and reporting measures are similar to those described in the **Federal Register** notice announcing issuance of the 2021 IHA (86 FR 38033, July 19, 2021; with the exception discussed below), and the discussion of the least practicable adverse impact included in that document remains accurate.

Following issuance of the 2021 IHA to SouthCoast Wind, NMFS' Greater Atlantic Regional Fisheries Office (GARFO) concluded a programmatic informal consultation regarding wind energy development-related surveys conducted in three Atlantic Renewable Energy Regions (<https://www.fisheries.noaa.gov/new-england-mid-atlantic/consultations/section-7-take-reporting-programmatics-greater-atlantic#offshore-wind-site-assessment-and-site-characterization-activities-programmatic-consultation>). Therefore, in addition to the mitigation, monitoring, and reporting measures prescribed through the 2021 IHA (86 FR 38033, July 19, 2021), SouthCoast Wind will be required to adhere to relevant Project Design Criteria (PDC) described in the GARFO consultation document (specifically PDCs 4, 5, and 7). The following measures are required for inclusion in this IHA.

Visual Monitoring and Shutdown Zones

NMFS-approved visual observers must be used. During survey operations (e.g., any day on which use of the sparker source is planned to occur, and whenever the sparker source is in the water, whether activated or not), a minimum of one visual marine mammal observer (i.e., PSO) must be on duty on each source vessel and conducting visual observations at all times during daylight hours (i.e., from 30 minutes prior to sunrise through 30 minutes following sunset). A minimum of two PSOs must be on duty on each source vessel during nighttime hours. Visual monitoring must begin no less than 30 minutes prior to ramp-up (described below) and must continue until one hour after use of the sparker source ceases.

Visual PSOs will coordinate to ensure 360° visual coverage around each vessel from the most appropriate observation posts and shall conduct visual observations using binoculars and the naked eye while free from distractions and in a consistent, systematic, and diligent manner. PSOs will establish and monitor applicable shutdown zones (see below). These zones will be based upon the radial distance from the

sparker source (rather than being based around the vessel itself).

Two shutdown zones are defined, depending on the species and context. Here, an extended shutdown zone encompassing the area at and below the sea surface out to a radius of 500 meters from the sparker source (0–500 meters) is defined for North Atlantic right whales. For all other marine mammals, the shutdown zone encompasses a standard distance of 100 meters (0–100 meters). Any observations of marine mammals by crew members aboard any vessel associated with the survey will be relayed to the PSO team.

Visual PSOs will be on watch for a maximum of 4 consecutive hours followed by a break of at least 1 hour between watches and may conduct a maximum of 12 hours of observation per 24-hour period.

Pre-Start Clearance and Ramp-Up

A ramp-up procedure, involving a gradual increase in source level output, is required at all times as part of the activation of the sparker source when technically feasible. Operators will ramp up sparkers to half power for 5 minutes and then proceed to full power. A 30-minute pre-start clearance observation period will occur prior to the start of ramp-up. The intent of pre-start clearance observation (30 minutes) is to ensure no marine mammals are within the shutdown zones prior to the beginning of ramp-up. The intent of ramp-up is to warn marine mammals of pending operations and to allow sufficient time for those animals to leave the immediate vicinity. All operators will adhere to the following pre-start clearance and ramp-up requirements:

- The operator will notify a designated PSO of the planned start of ramp-up as agreed upon with the lead PSO; the notification time should not be less than 60 minutes prior to the planned ramp-up in order to allow the PSOs time to monitor the shutdown zones for 30 minutes prior to the initiation of ramp-up (pre-start clearance). During this 30 minute pre-start clearance period the entire shutdown zone must be visible, except as indicated below.
- Ramp-ups will be scheduled so as to minimize the time spent with the source activated.
- A visual PSO conducting pre-start clearance observations will be notified again immediately prior to initiating ramp-up procedures and the operator must receive confirmation from the PSO to proceed.
- Any PSO on duty has the authority to delay the start of survey operations if

a marine mammal is detected within the applicable pre-start clearance zone.

- The operator will establish and maintain clear lines of communication directly between PSOs on duty and crew controlling the acoustic source to ensure that mitigation commands are conveyed swiftly while allowing PSOs to maintain watch.
- The pre-start clearance requirement is waived for small delphinids and pinnipeds. Detection of a small delphinid (individual belonging to the following genera of the Family Delphinidae: *Steno*, *Delphinus*, *Lagenorhynchus*, *Stenella*, and *Tursiops*) or pinniped within the shutdown zone will not preclude beginning of ramp-up, unless the PSO confirms the individual to be of a genus other than those listed, in which case normal pre-clearance requirements apply.
- If there is uncertainty regarding identification of a marine mammal species (i.e., whether the observed marine mammal(s) belongs to one of the delphinid genera for which the pre-clearance requirement is waived), PSOs will use best professional judgment in making the decision to call for a shutdown.
- Ramp-up will not be initiated if any marine mammal to which the prestart clearance requirement applies is within the shutdown zone. If a marine mammal is observed within the shutdown zone during the 30 minute pre-start clearance period, ramp-up will not begin until the animal(s) has been observed exiting the zones or until an additional time period has elapsed with no further sightings (30 minutes for all baleen whale species and sperm whales and 15 minutes for all other species).
- PSOs will monitor the shutdown zones 30 minutes before and during ramp-up, and ramp-up must cease and the source must be shut down upon observation of a marine mammal within the applicable shutdown zone.
- Ramp-up will occur at times of poor visibility, including nighttime, if appropriate visual monitoring has occurred with no detections of marine mammals in the 30 minutes prior to beginning ramp-up. Sparker activation will only occur at night where operational planning cannot reasonably avoid such circumstances.
- If the acoustic source is shut down for brief periods (i.e., less than 30 minutes) for reasons other than implementation of prescribed mitigation (e.g., mechanical difficulty), it may be activated again, without ramp-up, if PSOs have maintained constant visual observation and no detections of marine mammals have occurred within the

applicable shutdown zone. For any longer shutdown, pre-start clearance observation and ramp-up are required.

Shutdown

All operators will adhere to the following shutdown requirements:

- Any PSO on duty has the authority to call for shutdown of the sparker source if a marine mammal is detected within the applicable shutdown zone.
- The operator will establish and maintain clear lines of communication directly between PSOs on duty and crew controlling the source to ensure that shutdown commands are conveyed swiftly while allowing PSOs to maintain watch.
- When the sparker source is active and a marine mammal appears within or enters the applicable shutdown zone, the source will be shut down. When shutdown is instructed by a PSO, the source will be immediately deactivated and any dispute resolved only following deactivation.
- The shutdown requirement is waived for small delphinids and pinnipeds. If a small delphinid (individual belonging to the following genera of the Family Delphinidae: *Steno*, *Delphinus*, *Lagenorhynchus*, *Stenella*, and *Tursiops*) or pinniped is visually detected within the shutdown zone, no shutdown is required unless the PSO confirms the individual to be of a genus other than those listed, in which case a shutdown is required.
- If there is uncertainty regarding identification of a marine mammal species (*i.e.*, whether the observed marine mammal(s) belongs to one of the delphinid genera for which shutdown is waived or one of the species with a larger shutdown zone), PSOs will use best professional judgment in making the decision to call for a shutdown.
- Upon implementation of shutdown, the source will be reactivated after the marine mammal has been observed exiting the applicable shutdown zone or following a clearance period (30 minutes for all baleen whale species and sperm whales and 15 minutes for all other species) with no further detection of the marine mammal.

If a species for which authorization has not been granted, or a species for which authorization has been granted but the authorized number of takes have been met, approaches or is observed within the Level B harassment zone, shutdown will occur.

Vessel Strike Avoidance

Crew and supply vessel personnel will use an appropriate reference guide that includes identifying information on all marine mammals that may be

encountered. Vessel operators will comply with the below measures except under extraordinary circumstances when the safety of the vessel or crew is in doubt or the safety of life at sea is in question. These requirements do not apply in any case where compliance would create an imminent and serious threat to a person or vessel or to the extent that a vessel is restricted in its ability to maneuver and, because of the restriction, cannot comply.

- Vessel operators and crews will maintain a vigilant watch for all marine mammals and slow down, stop their vessel, or alter course, as appropriate and regardless of vessel size, to avoid striking any marine mammal. A single marine mammal at the surface may indicate the presence of submerged animals in the vicinity of the vessel; therefore, precautionary measures should always be exercised. A visual observer aboard the vessel must monitor a vessel strike avoidance zone around the vessel (species-specific distances detailed below). Visual observers monitoring the vessel strike avoidance zone will be third-party observers (*i.e.*, PSOs) or crew members, but crew members responsible for these duties must be provided sufficient training to: (1) distinguish marine mammal from other phenomena and (2) broadly to identify a marine mammal as a right whale, other whale (defined in this context as sperm whales or baleen whales other than right whales), or other marine mammals.

- All vessels, regardless of size, will observe a 10-knot speed restriction in specific areas designated by NMFS for the protection of North Atlantic right whales from vessel strikes. These include all Seasonal Management Areas (SMA) (when in effect), any dynamic management areas (DMA) (when in effect), and Slow Zones. See www.fisheries.noaa.gov/national/ending-endangered-species-conservation/reducing-shipstrikes-north-atlantic-right-whales for specific detail regarding these areas.

- Vessel speeds will also be reduced to 10 knots or less when mother/calf pairs, pods, or large assemblages of cetaceans are observed near a vessel.

- All vessels will maintain a minimum separation distance of 500 m from right whales. If a right whale is sighted within the relevant separation distance, the vessel will steer a course away at 10 knots or less until the 500-m separation distance has been established. If a whale is observed but cannot be confirmed as a species other than a right whale, the vessel operator will assume that it is a right whale and take appropriate action.

- All vessels will maintain a minimum separation distance of 100 m from sperm whales and all other baleen whales.

- All vessels will, to the maximum extent practicable, attempt to maintain a minimum separation distance of 50 m from all other marine mammals, with an understanding that at times this may not be possible (*e.g.*, for animals that approach the vessel).

- When marine mammals are sighted while a vessel is underway, the vessel will take action as necessary to avoid violating the relevant separation distance (*e.g.*, attempt to remain parallel to the animal's course, avoid excessive speed or abrupt changes in direction until the animal has left the area, reduce speed and shift the engine to neutral). This does not apply to any vessel towing gear or any vessel that is navigationally constrained.

Members of the PSO team will consult NMFS' North Atlantic right whale reporting system and Whale Alert, daily and as able, for the presence of North Atlantic right whales throughout survey operations, and for the establishment of DMAs and/or Slow Zones. It is SouthCoast Wind's responsibility to maintain awareness of the establishment and location of any such areas and to abide by these requirements accordingly.

PSOs

SouthCoast Wind will use independent, dedicated, trained PSOs, meaning that the PSOs will be employed by a third-party observer provider, will have no tasks other than to conduct observational effort, collect data, will communicate with and instruct relevant vessel crew with regard to the presence of marine mammal and mitigation requirements (including brief alerts regarding maritime hazards), and will have successfully completed an approved PSO training course for geophysical surveys. Visual monitoring will be performed by qualified, NMFS-approved PSOs. PSO resumes will be provided to NMFS for review and approval prior to the start of survey activities.

PSO names will be provided to NMFS by the operator for review and confirmation of their approval for specific roles prior to commencement of the survey. For prospective PSOs not previously approved, or for PSOs whose approval is not current, NMFS will review and approve PSO qualifications. Resumes should include information related to relevant education, experience, and training, including dates, duration, location, and description of prior PSO experience.

Resumes must be accompanied by relevant documentation of successful completion of necessary training.

NMFS may approve PSOs as conditional or unconditional. A conditionally approved PSO may be one who is trained but has not yet attained the requisite experience. An unconditionally-approved PSO is one who has attained the necessary experience. For unconditional approval, the PSO must have a minimum of 90 days at sea performing the role during a geophysical survey, with the conclusion of the most recent relevant experience not more than 18 months previous.

At least one of the visual PSOs aboard the vessel will be unconditionally approved. One unconditionally-approved visual PSO shall be designated as the lead for the entire PSO team. This lead should typically be the PSO with the most experience, who would coordinate duty schedules and roles for the PSO team and serve as primary point of contact for the vessel operator. To the maximum extent practicable, the duty schedule will be planned such that unconditionally-approved PSOs are on duty with conditionally-approved PSOs.

PSOs will successfully complete relevant training, including completion of all required coursework and passing (80 percent or greater) a written and/or oral examination developed for the training program.

PSOs will have successfully attained a bachelor's degree from an accredited college or university with a major in one of the natural sciences, a minimum of 30 semester hours or equivalent in the biological sciences, and at least one undergraduate course in math or statistics. The educational requirements may be waived if the PSO has acquired the relevant skills through alternate experience. Requests for such a waiver shall be submitted to NMFS and must include written justification. Alternate experience that may be considered includes, but is not limited to (1) secondary education and/or experience comparable to PSO duties; (2) previous work experience conducting academic, commercial, or government-sponsored marine mammal surveys; and (3) previous work experience as a PSO (PSO must be in good standing and demonstrate good performance of PSO duties).

SouthCoast Wind will work with the selected third-party PSO provider to ensure PSOs have all equipment (including backup equipment) needed to adequately perform necessary tasks, including accurate determination of distance and bearing to observed marine

mammals, and to ensure that PSOs are capable of calibrating equipment as necessary for accurate distance estimates and species identification. Such equipment, at a minimum, will include:

- At least one thermal (infrared) image device suited for the marine environment;
- Reticle binoculars (*e.g.*, 7 x 50) of appropriate quality (at least one per PSO, plus backups);
- Global Positioning Units (GPS) (at least one plus backups);
- Digital cameras with a telephoto lens that is at least 300-mm or equivalent on a full-frame single lens reflex (SLR) (at least one plus backups). The camera or lens should also have an image stabilization system;
- Equipment necessary for accurate measurement of distances to marine mammal;
- Compasses (at least one plus backups);
- Means of communication among vessel crew and PSOs; and
- Any other tools deemed necessary to adequately and effectively perform PSO tasks.

The equipment specified above will be provided by an individual PSO, the third-party PSO provider, or the operator, but SouthCoast Wind is responsible for ensuring PSOs have the proper equipment required to perform the duties specified in the final IHA.

The PSOs will be responsible for monitoring the waters surrounding the survey vessel to the farthest extent permitted by sighting conditions, including shutdown zones, during all HRG survey operations. PSOs will visually monitor and identify marine mammals, including those approaching or entering the established shutdown zones during survey activities. It will be the responsibility of the PSO(s) on duty to communicate the presence of marine mammals as well as to communicate the action(s) that are necessary to ensure mitigation and monitoring requirements are implemented as appropriate.

PSOs will be equipped with binoculars and have the ability to estimate distance and bearing to detect marine mammals, particularly in proximity to shutdown zones. Reticulated binoculars will also be available to PSOs for use as appropriate based on conditions and visibility to support the sighting and monitoring of marine mammals. During nighttime operations, night-vision goggles with thermal clip-ons and infrared technology will be available for use. Position data will be recorded using hand-held or vessel GPS units for each sighting.

During good conditions (*e.g.*, daylight hours; Beaufort sea state (BSS) 3 or less), to the maximum extent practicable, PSOs will also conduct observations when the acoustic source is not operating for comparison of sighting rates and behavior with and without use of the active acoustic sources. Any observations of marine mammals by crew members aboard the vessel associated with the survey will be relayed to the PSO team. Data on all PSO observations will be recorded based on standard PSO collection requirements. This will include dates, times, and locations of survey operations; dates and times of observations, location and weather; details of marine mammal sightings (*e.g.*, species, numbers, behavior); and details of any observed marine mammal behavior that occurs (*e.g.*, noted behavioral disturbances).

Reporting

SouthCoast Wind will submit a draft summary report on all activities and monitoring results within 90 days of the completion of the survey or expiration of the IHA, whichever comes sooner. The report will describe all activities conducted and sightings of marine mammals, will provide full documentation of methods, results, and interpretation pertaining to all monitoring, and will summarize the dates and locations of survey operations and all marine mammals sightings (dates, times, locations, activities, associated survey activities). The draft report will also include geo-referenced, timestamped vessel tracklines for all time periods during which acoustic sources were operating. Tracklines should include points recording any change in acoustic source status (*e.g.*, when the sources began operating, when they were turned off, or when they changed operational status such as from full array to single gun or vice versa). GIS files will be provided in Environmental Systems Research Institute, Inc. (ESRI) shapefile format and include the Universal Time Coordinated (UTC) date and time, latitude in decimal degrees, and longitude in decimal degrees. All coordinates will be referenced to the WGS84 geographic coordinate system. In addition to the report, all raw observational data will be made available. The report will summarize the information. A final report will be submitted within 30 days following resolution of any comments on the draft report. All draft and final marine mammal monitoring reports will be submitted to

PR.ITP.MonitoringReports@noaa.gov and *nmfs.gar.incidental-take@noaa.gov*.

PSOs will use standardized electronic data forms to record data. PSOs will record detailed information about any implementation of mitigation requirements, including the distance of marine mammal to the acoustic source and description of specific actions that ensued, the behavior of the animal(s), any observed changes in behavior before and after implementation of mitigation, and if shutdown was implemented, the length of time before any subsequent ramp-up of the acoustic source. If required mitigation was not implemented, PSOs will record a description of the circumstances. At a minimum, the following information will be recorded:

1. Vessel name (source vessel), vessel size and type, maximum speed capability of vessel;
2. Dates of departures and returns to port with port name;
3. PSO names and affiliations;
4. Date and participants of PSO briefings;
5. Visual monitoring equipment used;
6. PSO location on vessel and height of observation location above water surface;
7. Dates and times (Greenwich Mean Time) of survey on/off effort and times corresponding with PSO on/off effort;
8. Vessel location (decimal degrees) when survey effort begins and ends and vessel location at beginning and end of visual PSO duty shifts;
9. Vessel location at 30-second intervals if obtainable from data collection software, otherwise at practical regular interval;
10. Vessel heading and speed at beginning and end of visual PSO duty shifts and upon any change;
11. Water depth (if obtainable from data collection software);
12. Environmental conditions while on visual survey (at beginning and end of PSO shift and whenever conditions change significantly), including BSS and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon;
13. Factors that may contribute to impaired observations during each PSO shift change or as needed as environmental conditions change (e.g., vessel traffic, equipment malfunctions).
14. Survey activity information (and changes thereof), such as acoustic source power output while in operation, number and volume of airguns operating in an array, tow depth of an acoustic source, and any other notes of significance (i.e., pre-start clearance, ramp-up, shutdown, testing, shooting,

ramp-up completion, end of operations, streamers, etc.).

15. Upon visual observation of any marine mammal, the following information will be recorded:

- a. Watch status (sighting made by PSO on/off effort, opportunistic, crew, alternate vessel/platform);
 - b. Vessel/survey activity at time of sighting (e.g., deploying, recovering, testing, shooting, data acquisition, other);
 - c. PSO who sighted the animal;
 - d. Time of sighting;
 - e. Initial detection method;
 - f. Sightings cue;
 - g. Vessel location at time of sighting (decimal degrees);
 - h. Direction of vessel's travel (compass direction);
 - i. Speed of the vessel(s) from which the observation was made;
 - j. Identification of the animal (e.g., genus/species, lowest possible taxonomic level or unidentified); also note the composition of the group if there is a mix of species;
 - k. Species reliability (an indicator of confidence in identification);
 - l. Estimated distance to the animal and method of estimating distance;
 - m. Estimated number of animals (high/low/best);
 - n. Estimated number of animals by cohort (adults, yearlings, juveniles, calves, group composition, etc.);
 - o. Description (as many distinguishing features as possible of each individual seen, including length, shape, color, pattern, scars, or markings, shape and size of dorsal fin, shape of head, and blow characteristics);
 - p. Detailed behavior observations (e.g., number of blows/breaths, number of surfaces, breaching, spyhopping, diving, feeding, traveling; as explicit and detailed as possible; note any observed changes in behavior before and after point of closest approach);
 - q. Mitigation actions; description of any actions implemented in response to the sighting (e.g., delays, shutdowns, ramp-up, speed or course alteration, etc.) and time and location of the action;
 - r. Equipment operating during sighting;
 - s. Animal's closest point of approach and/or closest distance from the center point of the acoustic source; and
 - t. Description of any actions implemented in response to the sighting (e.g., delays, shutdown, ramp-up) and time and location of the action.
- If a North Atlantic right whale is observed at any time by PSOs or personnel on the project vessel, during surveys or during vessel transit, SouthCoast Wind will report the sighting information to the NMFS North

Atlantic Right Whale Sighting Advisory System (866-755-6622) within 2 hours of occurrence, when practicable, or no later than 24 hours after occurrence. North Atlantic right whale sightings in any location will also be reported to the U.S. Coast Guard via channel 16 and through the WhaleAlert app (www.whalealert.org).

In the event that personnel involved in the survey activities discover an injured or dead marine mammal, the incident will be reported to NMFS as soon as feasible by phone (866-755-6622) and by email (nmfs.gar.stranding@noaa.gov and *PR.ITP.MonitoringReports@noaa.gov*). The report will include the following information:

1. Time, date, and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
 2. Species identification (if known) or description of the animal(s) involved;
 3. Condition of the animal(s) (including carcass condition if the animal is dead);
 4. Observed behaviors of the animal(s), if alive;
 5. If available, photographs or video footage of the animal(s); and
 6. General circumstances under which the animal was discovered.
- In the event of a ship strike of a marine mammal by any vessel involved in the activities, SouthCoast Wind will report the incident to NMFS by phone (866-755-6622) and by email (nmfs.gar.stranding@noaa.gov and *PR.ITP.MonitoringReports@noaa.gov*) as soon as feasible. The report will include the following information:
1. Time, date, and location (latitude/longitude) of the incident;
 2. Species identification (if known) or description of the animal(s) involved;
 3. Vessel's speed during and leading up to the incident;
 4. Vessel's course/heading and what operations were being conducted (if applicable);
 5. Status of all sound sources in use;
 6. Description of avoidance measures/requirements that were in place at the time of the strike and what additional measures were taken, if any, to avoid strike;
 7. Environmental conditions (e.g., wind speed and direction, Beaufort sea state, cloud cover, visibility) immediately preceding the strike;
 8. Estimated size and length of animal that was struck;
 9. Description of the behavior of the marine mammal immediately preceding and/or following the strike;
 10. If available, description of the presence and behavior of any other

marine mammals immediately preceding the strike;

11. Estimated fate of the animal (*e.g.*, dead, injured but alive, injured and moving, blood or tissue observed in the water, status unknown, disappeared); and

12. To the extent practicable, photographs or video footage of the animal(s).

Determinations

SouthCoast Wind's HRG survey activities are unchanged from those analyzed in support of the 2021 IHA, with the exception of reductions in survey effort and vessels. The effects of the activity, taking into consideration the mitigation and related monitoring measures, remain unchanged from those evaluated in support of the 2021 IHA, regardless of the minor increases in estimated take numbers for some marine mammal species and/or stocks. Specifically, only Level B harassment has been authorized, which NMFS expects would be of a lower severity, predominately in the form of avoidance of the sound sources that may cause a temporary abandonment of the location during active source use that may result in a temporary interruption of foraging activities for some species. However, NMFS does not expect that this effect will long-term or permanent as the acoustic source would be mobile and leave the area within a specific amount of time for which the animals could return to the area. Even considering the increased estimated take for some species, the impacts of these lower severity exposures are not expected to accrue to a degree that the fitness of any individuals would be impacted, and therefore, no impacts on the annual rates of recruitment or survival would result.

As discussed in the previous **Federal Register** notices (86 FR 27393, May 20, 2021; 86 FR 38033, July 19, 2021), SouthCoast Wind's project will occur approximately 50 miles (80.5 km) west of the feeding BIAs for North Atlantic right whales (February–April) and sei whales (May–November) and approximately 40 miles (64.4 km) west of feeding BIAs for humpback whales (March–December) and fin whales (March–October). The Narragansett Bay cable route corridor is located just to the north of another fin whale BIA (March–October) south of Martha's Vineyard. These BIAs are extensive and sufficiently large (705 km² and 3,149 km² for North Atlantic right whales; 47,701 km² for humpback whales; 2,933 km² for fin whales; and 56,609 km² for sei whales), and the acoustic footprint of the planned survey is sufficiently small

(141 m using the sparker), such that feeding opportunities for these whales would not be reduced appreciably. Furthermore, given SouthCoast Wind's reduced vessel presence, the reduced daily vessel tracks, and the reduced number of days for the project, NMFS expects any impacts from this project to be less than were expected in association with the previous 2021–2022 project.

NMFS has also reviewed current information regarding active Unusual Mortality Events (UMEs) and important habitat, and finds that the discussion provided for the 2021 IHA remains applicable to this final IHA. Therefore, in conclusion, there is no new information suggesting that our analysis or findings should change.

Based on the information contained here and in the referenced documents, NMFS has determined the following: (1) the required mitigation measures will effect the least practicable impact on marine mammal species or stocks and their habitat; (2) the authorized takes will have a negligible impact on the affected marine mammal species or stocks; (3) the authorized takes represent small numbers of marine mammals relative to the affected stock abundances; (4) SouthCoast Wind's activities will not have an unmitigable adverse impact on taking for subsistence purposes as no relevant subsistence uses of marine mammals are implicated by this action, and (5) appropriate monitoring and reporting requirements are included.

Endangered Species Act (ESA)

Section 7(a)(2) of the Endangered Species Act of 1973 (ESA; 16 U.S.C. 1531 *et seq.*) requires that each Federal agency insure that any action it authorizes, funds, or carries out 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. To ensure ESA compliance for the issuance of IHAs, NMFS Office of Protected Resources (OPR) consults internally whenever we propose to authorize take for endangered or threatened species.

NMFS OPR has authorized the incidental take of four species of marine mammals which are listed under the ESA, including the North Atlantic right, fin, sei, and sperm whale, and has determined that these activities fall within the scope of activities analyzed in GARFO's programmatic consultation regarding geophysical surveys along the U.S. Atlantic coast in the three Atlantic Renewable Energy Regions (completed June 29, 2021; revised September 2021).

The consultation concluded that NMFS' issuance of incidental take authorization related to these activities are not likely to adversely affect ESA-listed marine mammals.

National Environmental Policy Act

To comply with the National Environmental Policy Act of 1969 (NEPA; 42 U.S.C. 4321 *et seq.*) and NOAA Administrative Order (NAO) 216–6A, NMFS must review our action (*i.e.*, the issuance of an IHA) with respect to potential impacts on the human environment. This action is consistent with categories of activities identified in Categorical Exclusion B4 (IHAs with no anticipated serious injury or mortality) of the Companion Manual for NOAA Administrative Order 216–6A, which do not individually or cumulatively have the potential for significant impacts on the quality of the human environment and for which we have not identified any extraordinary circumstances that would preclude this categorical exclusion. Accordingly, NMFS has determined that the issuance of the final IHA qualifies to be categorically excluded from further NEPA review.

Authorization

As a result of these determinations, NMFS has issued an IHA to SouthCoast Wind for conducting site characterization surveys off Massachusetts and Rhode Island from May 12, 2023 through May 11, 2024, provided the previously mentioned mitigation, monitoring, and reporting requirements are incorporated. The final IHA and SouthCoast Wind's IHA application can be found on NMFS' website at <https://www.fisheries.noaa.gov/permit/incidental-take-authorizations-under-marine-mammal-protection-act>.

Dated: May 12, 2023.

Catherine Marzin,

Deputy Director, Office of Protected Resources, National Marine Fisheries Service.

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DEPARTMENT OF COMMERCE**National Oceanic and Atmospheric Administration**

[RTID 0648–XC890]

Takes of Marine Mammals Incidental to Specified Activities; Taking Marine Mammals Incidental to the Punta Gorda Lighthouse Stabilization Project in Humboldt County, California

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of an incidental harassment authorization.

SUMMARY: In accordance with the regulations implementing the Marine Mammal Protection Act (MMPA) as amended, notification is hereby given that NMFS has issued an incidental harassment authorization (IHA) to the Bureau of Land Management (BLM) for authorization to incidentally harass marine mammals during construction activities associated with Phase 2 of the Punta Gorda Lighthouse (PGL) Stabilization Project in Humboldt County, California.

DATES: This authorization is effective from June 1, 2023, through October 1, 2023.

FOR FURTHER INFORMATION CONTACT: Kate Fleming, Office of Protected Resources, NMFS, (301) 427–8401.

Electronic copies of the application and supporting documents, as well as a list of the references cited in this document, may be obtained online at: <https://www.fisheries.noaa.gov/national/marine-mammal-protection/incidental-take-authorizations-construction-activities>. In case of problems accessing these documents, please call the contact listed above.

SUPPLEMENTARY INFORMATION:**Background**

The MMPA prohibits the “take” of marine mammals, with certain exceptions. Section 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) directs the Secretary of Commerce (as delegated to NMFS) to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are proposed or, if the taking is limited to harassment, a notice of a proposed IHA is provided to the public for review.

Authorization for incidental takings shall be granted if NMFS finds that the

taking will have a negligible impact on the species or stock(s) and will not have an unmitigable adverse impact on the availability of the species or stock(s) for taking for subsistence uses (where relevant). Further, NMFS must prescribe the permissible methods of taking and other “means of effecting the least practicable adverse impact” on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stocks for taking for certain subsistence uses (referred to in shorthand as “mitigation”); and requirements pertaining to the mitigation, monitoring, and reporting of the takings are set forth. The definitions of all applicable MMPA statutory terms cited above are included in the relevant sections below.

Summary of Request

On October 26, 2022, NMFS received a request from BLM for an IHA to take marine mammals incidental to Phase 2 of the PGL Stabilization Project in Humboldt County, California. Following NMFS’ review of the application, BLM submitted a revised version on January 27, 2023, and again on February 8, 2023. The application was deemed adequate and complete on February 9, 2023. BLM’s request is for take of northern elephant seal (*Mirounga angustirostris*), Pacific harbor seal (*Phoca vitulina richardii*), California sea lion (*Zalophus californianus*), and Steller sea lion (*Eumetopias jubatus*) by Level B harassment only. Neither BLM nor NMFS expect serious injury or mortality to these marine mammals to result from this activity and, therefore, an IHA is appropriate.

NMFS previously issued an IHA to BLM for related work (87 FR 34659, June 7, 2022). BLM complied with all the requirements (e.g., mitigation, monitoring, and reporting) of the previous IHA and information regarding their monitoring results may be found in the Effects of the Specified Activity on Marine Mammals and Their Habitat section in the **Federal Register** notice for the proposed IHA (88 FR 17525, March 23, 2023) and Estimated Take sections.

This IHA covers the final year of work of a larger project for which BLM obtained a prior IHA. The larger 2-year project involves construction activities to restore all remaining buildings of the PGL Site. There are no changes from the proposed IHA to the final IHA.

Description of the Planned Activity**Overview**

The PGL was established as an aid to navigation in 1912 along the northern California coast. While in use, the lighthouse station included the lighthouse, oil house, three residences, and numerous other small buildings typical of small military outposts. The U.S. Coast Guard decommissioned the lighthouse in 1951. BLM assumed management of the site following the PGL’s decommission. The concrete lighthouse and oil house were all that remained when the site was listed in the National Registry of Historic Places in 1976.

BLM repaired and stabilized the lighthouse building itself during the summer of 2022. Construction activities are planned to repair and stabilize the remaining structure at the site, which is an oil house. Human presence, noise from construction work, and noise from and/or presence of supply transport vehicles may result in behavioral disturbance primarily of harbor seals and northern elephant seals, and potentially California sea lions and Steller sea lions. The project will take no more than 122 construction days between June and September 2023.

A detailed description of the planned lighthouse stabilization project is provided in the **Federal Register** notice for the proposed IHA (88 FR 17525, March 23, 2023). Since that time, no changes have been made to the planned construction activities. Therefore, a detailed description is not provided here. Please refer to that **Federal Register** notice for the description of the specific activity.

Mitigation, monitoring, and reporting measures are described in detail later in this document (please see Mitigation and Monitoring and Reporting sections).

Comments and Responses

A notice of NMFS’s proposal to issue an IHA to BLM was published in the **Federal Register** on March 23, 2023 (88 FR 17525). That notice described, in detail, BLM’s activity, the marine mammal species that may be affected by the activity, and the anticipated effects on marine mammals. During the 30-day public comment period, the United States Geological Survey noted that they have “no comment at this time”. NMFS received no other public comments.

Description of Marine Mammals in the Area of Specified Activities

Sections 3 and 4 of the application summarize available information regarding status and trends, distribution and habitat preferences, and behavior

and life history of the potentially affected species. NMFS fully considered all of this information, and we refer the reader to these descriptions, incorporated here by reference, instead of reprinting the information. Additional information regarding population trends and threats may be found in NMFS' Stock Assessment Reports (SARs; www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments) and more general information about these species (e.g., physical and behavioral descriptions) may be found on NMFS' website (<https://www.fisheries.noaa.gov/find-species>).

Table 1 lists all species or stocks for which take is expected and authorized for this activity, and summarizes

information related to the population or stock, including regulatory status under the MMPA and Endangered Species Act (ESA), and potential biological removal (PBR), where known. PBR is defined by the MMPA as the maximum number of animals, not including natural mortalities, that may be removed from a marine mammal stock while allowing that stock to reach or maintain its optimum sustainable population (as described in NMFS' SARs). While no serious injury or mortality is authorized here, PBR and annual serious injury and mortality from anthropogenic sources are included here as gross indicators of the status of the species or stocks and other threats.

Marine mammal abundance estimates presented in this document represent

the total number of individuals that make up a given stock or the total number estimated within a particular study or survey area. NMFS' stock abundance estimates for most species represent the total estimate of individuals within the geographic area, if known, that comprises that stock. For some species, this geographic area may extend beyond U.S. waters. All managed stocks in this region are assessed in NMFS' U.S. Pacific and Alaska SARs. All values presented in Table 1 are the most recent available at the time of publication (including from the draft 2022 SARs) and are available online at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments.

TABLE 1—SPECIES LIKELY IMPACTED BY THE SPECIFIED ACTIVITIES

Common name	Scientific name	Stock	ESA/ MMPA status; strategic (Y/N) ¹	Stock abundance (CV, N _{min} , most recent abundance survey) ²	PBR	Annual M/SI ³
Order Carnivora—Superfamily Pinnipedia						
Family Otariidae (eared seals and sea lions):						
Steller sea lion	<i>Eumatopias jubata</i>	Eastern U.S.	-, -, N	43,201 (N/A, 43,201, 2017) ...	2,592	112
California sea lion	<i>Zalophus californica</i>	U.S.	-, -, N	257,606 (N/A, 233,515, 2014)	14,011	≥321
Family Phocidae (earless seals):						
Northern elephant seal	<i>Mirounga angustirostris</i>	California Breeding	-, -, N	187,386 (N/A, 85,369, 2013)	5,122	13.7
Pacific Harbor seal	<i>Phoca vitulina richardii</i>	California	-, -, N	30,968 (N/A 27,348, 2012)	1,641	43

¹ ESA status: Endangered (E), Threatened (T)/MMPA status: Depleted (D). A dash (-) indicates that the species is not listed under the ESA or designated as depleted under the MMPA. Under the MMPA, a strategic stock is one for which the level of direct human-caused mortality exceeds PBR or which is determined to be declining and likely to be listed under the ESA within the foreseeable future. Any species or stock listed under the ESA is automatically designated under the MMPA as depleted and as a strategic stock.

² NMFS marine mammal stock assessment reports online at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments. CV is coefficient of variation; N_{min} is the minimum estimate of stock abundance. In some cases, CV is not applicable.

³ These values, found in NMFS's SARs, represent annual levels of human-caused mortality plus serious injury from all sources combined (e.g., commercial fisheries, ship strike). Annual M/SI often cannot be determined precisely and is in some cases presented as a minimum value or range.

As indicated above, all four species (with four managed stocks) in Table 1 temporally and spatially co-occur with the activity to the degree that take is reasonably likely to occur.

A detailed description of the of the species likely to be affected by the lighthouse stabilization project, including brief introductions to the species and relevant stocks as well as available information regarding population trends and threats, and information regarding local occurrence, were provided in the **Federal Register** notice for the proposed IHA (88 FR 17525, March 23, 2023); since that time, we are not aware of any changes in the status of these species and stocks; therefore, detailed descriptions are not provided here. Please refer to that **Federal Register** notice for these descriptions. Please also refer to NMFS' website (<https://www.fisheries.noaa.gov/find-species>) for generalized species accounts.

Potential Effects of Specified Activities on Marine Mammals and Their Habitat

Acoustic and visual stimuli generated by personnel working at the PGL and traversing the beach to access the work site, noise from construction equipment operating at PGL, and helicopters hovering over the site to transport equipment and supplies may have the potential to cause behavioral disturbance (Level B harassment) of marine mammals in the vicinity of the project area. The **Federal Register** notice of the proposed IHA (88 FR 17525, March 23, 2023) included a discussion of the effects of anthropogenic activity on marine mammals and their habitat. That information and analysis is incorporated by reference into the final determination for the IHA and is not repeated here; please refer to the notice of proposed IHA (88 FR 17525, March 23, 2023).

The Estimated Take section later in this document includes a quantitative

analysis of the number of individuals that are expected to be taken by this activity. The Negligible Impact Analysis and Determination section considers the content of this section, the Estimated Take section, and the Mitigation section, to draw conclusions regarding the likely impacts of these activities on the reproductive success or survivorship of individuals and whether those impacts are reasonably expected to, or reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival.

Estimated Take

This section provides an estimate of the number of incidental takes authorized through the IHA, which will inform both NMFS' consideration of "small numbers," and the negligible impact determinations.

Harassment is the only type of take expected to result from these activities. Except with respect to certain activities not pertinent here, section 3(18) of the

MMPA defines “harassment” as any act of pursuit, torment, or annoyance, which (i) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment); or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment).

Authorized takes will be by Level B harassment only, in the form of disruption of behavioral patterns for individual marine mammals resulting from exposure to construction personnel and equipment, including helicopters used to transport materials. Based on the nature of the activity, Level A harassment is neither anticipated nor

authorized. For BLM’s activities, behavioral (Level B) harassment is limited to movement and flushing, defined by the disturbance scale of pinniped responses (Table 2).

The presence of construction personnel may have the potential to cause Level B harassment of marine mammals hauled-out at the PGL and along the planned access route. Disturbance includes a variety of effects, from subtle to conspicuous changes in behavior, movement, and displacement. Disturbance may result in reactions ranging from an animal simply becoming alert to the presence of BLM’s construction personnel (*e.g.*, turning the head, assuming a more upright posture) to flushing from the haulout site into the water. NMFS does not consider the lesser reactions to constitute behavioral

harassment, or Level B harassment takes, but rather assumes that pinnipeds that move greater than two body lengths or longer, or if already moving, a change of direction of greater than 90 degrees in response to the disturbance, or pinnipeds that flush into the water, are behaviorally harassed, and thus considered incidentally taken by Level B harassment. NMFS uses a 3-point scale (Table 2) to determine which disturbance reactions constitute take under the MMPA. Levels 2 and 3 (movement and flush) are considered take, whereas level 1 (alert) is not. Animals that respond to the presence of BLM personnel by becoming alert, but do not move or change the nature of locomotion as described, are not considered to have been subject to behavioral harassment.

TABLE 2—DISTURBANCE SCALE OF PINNIPED RESPONSES

Level	Type of response	Definition
1	Alert	Seal head orientation or brief movement in response to disturbance, which may include turning head towards the disturbance, craning head and neck while holding the body rigid in a u-shaped position, changing from a lying to a sitting position, or brief movement of less than twice the animal’s body length.
2*	Movement	Movements in response to the source of disturbance, ranging from short withdrawals at least twice the animal’s body length to longer retreats over the beach, or if already moving a change of direction of greater than 90 degrees.
3*	Flush	All retreats (flushes) to the water.

*Only Levels 2 and 3 are considered take under the MMPA. Level 1 is not considered take.

As described previously, no serious injury or mortality is anticipated or authorized for this activity. Below we describe how the authorized take numbers are calculated.

Marine Mammal Occurrence

In this section we provide information about the occurrence of marine

mammals, including density or other relevant information that will inform the take calculations.

Researchers from Humboldt State University (HSU) regularly conduct census counts of pinnipeds at the PGL and surrounding areas along the northern California coast (*e.g.*, Goley *et al.*, 2021, BLM 2022). Protected Species

Observers (PSOs) on site during the first year of construction recorded daily counts as well. Counts of northern elephant seals, harbor seals, California sea lion, and Steller sea lion at the PGL during the effective dates of the issued IHA (June 1 until October 1) are presented below.

TABLE 3—PINNIPED CENSUS COUNTS AT PUNTA GORDA LIGHTHOUSE

Date	Number of elephant seals observed	Number of harbor seals observed *	Number of California sea lions observed *	Number of Steller sea lions observed *
2019 Counts				
June 8	101	51	-	-
June 15	74	107	-	-
June 23	34	81	-	-
July 7	40	116	-	-
July 14	50	180	-	-
July 21	54	123	-	-
August 3	39	105	-	-
August 21	44	80	-	-
August 31	62	22	-	-
September 15	162	22	-	-
September 27	244	28	-	-
2020 Counts				
June 4	177	-	-	-
June 11	83	-	-	-

TABLE 3—PINNIPED CENSUS COUNTS AT PUNTA GORDA LIGHTHOUSE—Continued

Date	Number of elephant seals observed	Number of harbor seals observed *	Number of California sea lions observed *	Number of Steller sea lions observed *
June 14	80	55	-	-
June 24	37	-	-	-
June 27	38	77	-	-
July 4	36	-	-	-
July 12	39	90	-	-
July 16	38	-	-	-
July 24	36	123	-	-
July 30	38	-	-	-
August 6	32	-	-	-
August 9	28	73	-	-
August 13	28	-	-	-
August 20	27	-	-	-
August 27	33	-	-	-
August 30	48	36	-	-
September 5	60	38	-	-
September 19	133	51	-	-
September 27	177	53	-	-

2021 Counts

June 10	199	-	-	-
June 29	59	109	-	-
July 10	48	128	-	-
July 26	34	104	-	-
August 7	30	103	-	-
August 22	42	68	-	-
September 2	106	-	-	-
September 16	135	-	-	-

2022 Counts

June 22	39	42	0	0
June 23	53	50	0	0
June 24	34	117	0	0
June 25	50	110	0	0
June 27	38	150	0	0
June 28	61	126	0	0
June 29	54	132	0	0
June 30	56	169	0	0
July 1	52	137	0	0
July 5	48	156	0	0
July 6	51	142	0	0
July 7	34	-	0	0
July 8	33	121	0	0
July 9	56	141	0	0
July 11	28	106	0	0
July 12	37	139	0	1
July 13	38	156	0	0
July 14	34	190	0	0
July 15	37	134	0	0
July 16	30	136	0	0
July 18	29	114	0	0
July 19	30	108	0	0
July 20	25	122	0	0
July 21	27	99	0	0
July 22	32	109	0	0
July 23	31	109	0	0
July 25	29	115	0	0
July 26	33	93	0	0
July 27	30	58	0	0
July 28	29	91	0	0
July 29	33	73	0	0
August 1	31	82	0	0
August 2	28	76	0	0
August 4	32	77	0	0
August 5	28	105	2	0
August 6	29	72	0	0
August 8	26	71	0	0
August 9	27	55	10	0
August 10	28	48	7	0

TABLE 3—PINNIPED CENSUS COUNTS AT PUNTA GORDA LIGHTHOUSE—Continued

Date	Number of elephant seals observed	Number of harbor seals observed *	Number of California sea lions observed *	Number of Steller sea lions observed *
August 11	32	41	0	0
August 12	38	56	0	0
August 15	34	46	0	0
August 16	40	56	3	0
August 17	42	61	0	0
August 18	44	50	0	0
August 19	42	64	0	0
August 20	39	56	0	0
August 22	40	57	7	0
August 23	48	58	6	0
August 24	48	60	0	0
August 25	54	59	0	0
August 26	51	48	0	0
August 27	54	38	0	0
August 29	65	37	0	0
August 30	57	51	1	0
August 31	46	49	0	0
September 1	60	41	0	0
Daily Average	52.4	87.4	0.6	0.02

* Dashes (-) refer to instance where researchers did not record occurrence information.

Between 2019 and 2022, census counts of elephant seals and harbor seals were collected at PGL during the effective dates of the IHA (June 1–October 1). Across all 4 years, the average daily count was 52.4 elephant seals (Goley *et al.*, 2021, BLM 2022). A large proportion of the elephant seals present at PGL are uniquely tagged and dye stamped to identify individuals and the same individuals were identified at the PGL haulout on multiple days. Across all 4 years, the daily average of harbor seals was 87.4. The harbor seals present at the PGL are not tagged or otherwise clearly identifiable, but since harbor seals typically show hauling site fidelity (Herder 1986, Yochem *et al.*, 1987, Dietz *et al.*, 2012, Waring *et al.*, 2016), researchers from HSU hypothesize that the harbor seal colony at the PGL is made up of the same individuals that move between Punta Gorda and other nearby haulouts.

During the first year of construction (June–October 2022), PSOs recorded the number of California and Steller sea lions present in the PGL area. The daily average count of California sea lions was 0.6 and the daily average count of Steller sea lions was 0.02.

Take Estimation

Here we describe how the information provided above is synthesized to produce a quantitative estimate of the take that is reasonably likely to occur for authorization.

To estimate the total number of pinnipeds that may be present at the PGL and subject to behavioral disturbance from the PGL stabilization project, BLM multiplied the daily count of each species averaged across all years of available census data (52.4 elephant seals, 87.4 harbor seals, 0.6 California sea lions, and 0.02 Steller sea lions) by the maximum days of work at the PGL (122 days), for an estimated total take events of 6,393 for northern elephant

seals, 10,663 for harbor seals, 73 for California sea lions, and 2 for Steller sea lions) taken by Level B harassment. This estimation assumes that all animals present will exhibit behavioral responses that are considered take (Levels 2 and Level 3 as described in Table 2). As described above, many of the seals present at the PGL are suspected or confirmed to be present across multiple days. Therefore, the above estimated take numbers are considered to represent instances of take, not necessarily the number of individual seals that may be taken. In the case of Steller sea lion, two takes may not adequately account for all instances of possible take that could occur should multiple individuals enter the project area over the course of construction, or one individual enter the project area on multiple occasions. As such the take estimate for this species has been increased to 30 as requested by the applicant.

TABLE 4—AUTHORIZED TAKE BY LEVEL B HARASSMENT BY SPECIES AND PERCENTAGE OF EACH STOCK AFFECTED

Species	Stock	^a Authorized take by Level B harassment	Stock abundance	Percent of stock
Northern elephant seal	California breeding	6,393	187,386	3.4
Pacific harbor seal	California	10,663	30,968	34.4
California sea lion	U.S.	73	257,606	0.03
Steller sea lion	Eastern U.S.	30	77,149	0.04

^a The authorized take represents the estimated number of instances of take, which does not equate to the number of individuals that may be taken.

Mitigation

In order to issue an IHA under section 101(a)(5)(D) of the MMPA, NMFS must set forth the permissible methods of taking pursuant to the activity, and other means of effecting the least practicable impact on the species or stock and its habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stock for taking for certain subsistence uses (latter not applicable for this action). NMFS regulations require applicants for incidental take authorizations to include information about the availability and feasibility (economic and technological) of equipment, methods, and manner of conducting the activity or other means of effecting the least practicable adverse impact upon the affected species or stocks, and their habitat (50 CFR 216.104(a)(11)).

In evaluating how mitigation may or may not be appropriate to ensure the least practicable adverse impact on species or stocks and their habitat, as well as subsistence uses where applicable, NMFS considers two primary factors:

(1) The manner in which, and the degree to which, the successful implementation of the measure(s) is expected to reduce impacts to marine mammals, marine mammal species or stocks, and their habitat. This considers the nature of the potential adverse impact being mitigated (likelihood, scope, range). It further considers the likelihood that the measure will be effective if implemented (probability of accomplishing the mitigating result if implemented as planned), the likelihood of effective implementation (probability implemented as planned); and

(2) The practicability of the measures for applicant implementation, which may consider such things as cost, and impact on operations.

The following mitigation measures are required:

The work season has been planned to reduce the level of impact on elephant and harbor seals. The effective dates of the IHA (June 1, 2022 through October 1, 2022) occur when the elephant seal presence is at its lowest and any harbor seal pups that may be on site will be old enough to be self-sufficient if the colony temporarily flushes into the water. No elephant seal pups are expected to be present during the work season.

To the extent possible, BLM will limit the daily number of vehicle trips between the project area and the contractor's offshore camp where additional tools and supplies will be

stored in trailers or other storage containers.

While accessing and departing the project site, trained PSOs will monitor ahead of the vehicle(s) path, using binoculars if necessary, to detect any marine mammals prior to approach to determine if mitigation (e.g., change of course, slow down) is required. Vehicles will not approach within 20 m of marine mammals. If animals remain in the access path with no possible route to go around and maintain 20 m separation, a PSO may walk toward the animals and intentionally flush them into the water to allow the vehicle(s) to proceed. To the extent possible, if multiple vehicles are traveling to the site, they should travel in a convoy such that animals are not potentially harassed more than once while the vehicles pass.

At least one PSO will arrive onsite 10 minutes ahead of contractors each day to obtain counts in two separate locations viewing both haulouts before work commences.

A fence will be erected to keep elephant seals from entering the construction area to limit disturbance and prevent accidental injury from vehicles and construction debris.

All helicopters associated with the project will slowly approach the work site and allow all marine mammals present to flush into the water before setting any hauled materials down on the ground.

BLM must cease or delay visits to the project site if a species for which the number of takes that have been authorized for a species are met, or if a species for which takes were not authorized, is observed.

Based on our evaluation of the applicant's planned measures, NMFS has determined that the mitigation measures provide the means of effecting the least practicable impact on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance.

Monitoring and Reporting

In order to issue an IHA for an activity, section 101(a)(5)(D) of the MMPA states that NMFS must set forth requirements pertaining to the monitoring and reporting of such taking. The MMPA implementing regulations at 50 CFR 216.104(a)(13) indicate that requests for authorizations must include the suggested means of accomplishing the necessary monitoring and reporting that will result in increased knowledge of the species and of the level of taking or impacts on populations of marine mammals that are expected to be present while conducting the activities.

Effective reporting is critical both to compliance as well as ensuring that the most value is obtained from the required monitoring.

Monitoring and reporting requirements prescribed by NMFS should contribute to improved understanding of one or more of the following:

- Occurrence of marine mammal species or stocks in the area in which take is anticipated (e.g., presence, abundance, distribution, density);
- Nature, scope, or context of likely marine mammal exposure to potential stressors/impacts (individual or cumulative, acute or chronic), through better understanding of: (1) action or environment (e.g., source characterization, propagation, ambient noise); (2) affected species (e.g., life history, dive patterns); (3) co-occurrence of marine mammal species with the activity; or (4) biological or behavioral context of exposure (e.g., age, calving or feeding areas);
- Individual marine mammal responses (behavioral or physiological) to acoustic stressors (acute, chronic, or cumulative), other stressors, or cumulative impacts from multiple stressors;
- How anticipated responses to stressors impact either: (1) long-term fitness and survival of individual marine mammals; or (2) populations, species, or stocks;
- Effects on marine mammal habitat (e.g., marine mammal prey species, acoustic habitat, or other important physical components of marine mammal habitat); and,
- Mitigation and monitoring effectiveness.

Visual Monitoring

At least one NMFS-approved PSO will travel to and from the construction site ahead of the work crew each day and serve as a lead monitor to record incidental take. PSOs will consist of BLM wildlife biologists, biological technicians, and interns, as well as King Range National Conservation Area staff. At least one PSO will monitor the beach surrounding the PGL during all construction activities.

PSOs should have the following qualifications:

- Ability to conduct field observations and collect data according to assigned protocols;
- Experience or training in the field identification of marine mammals, including the identification of behaviors;
- Sufficient training, orientation, or experience with the construction

operation to provide for personal safety during observations;

- Writing skills sufficient to prepare a report of observations including but not limited to the number of species of marine mammals observed; dates and times when construction activities were conducted; dates, times, and reason for implementation of mitigation (or why mitigation was not implemented when required); and marine mammal behavior; and

- Ability to communicate orally, by radio or in person, with project personnel to provide real-time information on marine mammal observed in the area when necessary.

PSOs must record the following information for each day of work:

- Date, time, and access route of each visit to the work site;
- Information on the weather, including tidal state and estimated horizontal visibility;
- Composition of marine mammals observed, such as species, sex, and life history stage (*e.g.*, adult, sub-adult, pup);
- Estimated numbers (by species) of marine mammals observed during the activities;
- Location of marine mammals observed during construction activities.
- Marine mammal disturbances according to a three-point scale of intensity (see Table 2)
- Behavioral responses or modifications of behaviors that may be attributed to the specific activities, a description of the specific activities occurring during that time (*e.g.*, pedestrian, vehicle, or helicopter approach), and any mitigation action taken; and
- Note the presence of any offshore predators (date, time, number, and species).

Reporting

The BLM will report all observations of marked or tag-bearing pinnipeds or carcasses and unusual behaviors, distributions, or numbers of pinnipeds to the NMFS West Coast Regional Office.

A draft marine mammal monitoring report will be submitted to NMFS within 90 days after the completion of each work season, or 60 days prior to the requested issuance date of any future IHAs for projects at the same location, whichever comes first. A final report must be prepared and submitted within 30 days following resolution of any comments on the draft report from NMFS. If no comments are received from NMFS on the draft report, the draft report will be considered the final report. The marine mammal report will

include an overall description of work completed, a narrative regarding marine mammal sightings and behavioral response to construction activities, and associated PSO data sheets.

In addition to submitting raw sightings data, the report must include:

- Dates, and times (begin and end) of all marine mammal monitoring;
- Construction activities occurring during each daily observation period such as supply transport via ground and/or helicopter, fence installation, trail maintenance, and demolition *etc.*;
- PSO locations during marine mammal monitoring; and
- Environmental conditions during monitoring periods (at beginning and end of PSO shift and whenever conditions change significantly), and any relevant weather conditions including fog, sun glare, and estimated observable distance.

Prior to the commencement of activities, on each subsequent hour during construction, and before finishing construction each day, PSOs will record and report the following marine mammal observations:

- Name of the PSO who completed the observations and PSO location and activity at the time of recording;
 - Time of observation;
 - The number (by species) of marine mammals observed during the activities, by age and sex, if possible, and distances to construction activities. Data may be reported according to groups in cases where animals are concentrated together;
 - The behavioral response of marine mammals (by species, age, and sex as possible) to construction activities based on the 3 point scale (Table 2), including distances to construction activities and descriptions of construction activities occurring at the time of observance.
- When pinnipeds are concentrated in groups, closest distance of the group to construction activities may be reported; and

- A description of the implementation and effectiveness of the monitoring and mitigation measures of the IHA and full documentation of methods, results, and interpretation pertaining to all monitoring.

Separately, the same information should be recorded and reported each time Level 2 or Level 3 harassment of marine mammals is observed.

Reporting Injured or Dead Marine Mammals

In the event that BLM or any other personnel involved in the activities discover an injured or dead marine mammal, BLM will report the incident to the NMFS Office of Protected

Resources (*PR.ITP.MonitoringReports@noaa.gov*) and to the West Coast Regional Stranding Coordinator as soon as feasible. If the death or injury were clearly caused by a specific activity, BLM will immediately cease the specified activities until NMFS is able to review the circumstances of the incident and determine what, if any, additional measures are appropriate to ensure compliance with the terms of the IHA. BLM will not resume their activities until notified by NMFS. The report must include the following information:

- Time, date, and location (latitude and longitude) of the first discovery (and updated location information if known and applicable);
- Species identification (if known) or description of the animal(s) involved;
- Condition of the animal(s) (including carcass condition of the animal is dead);
- Observed behaviors of the animal(s), if alive;
- If available, photographs or video footage of the animal(s); and
- General circumstances under which the animal was discovered.

Negligible Impact Analysis and Determination

NMFS has defined negligible impact as an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival (50 CFR 216.103). A negligible impact finding is based on the lack of likely adverse effects on annual rates of recruitment or survival (*i.e.*, population-level effects). An estimate of the number of takes alone is not enough information on which to base an impact determination. In addition to considering estimates of the number of marine mammals that might be “taken” through harassment, NMFS considers other factors, such as the likely nature of any impacts or responses (*e.g.*, intensity, duration), the context of any impacts or responses (*e.g.*, critical reproductive time or location, foraging impacts affecting energetics), as well as effects on habitat, and the likely effectiveness of the mitigation. We also assess the number, intensity, and context of estimated takes by evaluating this information relative to population status. Consistent with the 1989 preamble for NMFS’ implementing regulations (54 FR 40338, September 29, 1989), the impacts from other past and ongoing anthropogenic activities are incorporated into this analysis via their impacts on the baseline (*e.g.*, as

reflected in the regulatory status of the species, population size and growth rate where known, ongoing sources of human-caused mortality, or ambient noise levels).

To avoid repetition, the discussion of our analysis applies to all the species listed in Table 4, given that the anticipated effects of this activity on these different marine mammal stocks are expected to be similar. There is little information about the nature or severity of the impacts, or the size, status, or structure of any of these species or stocks that will lead to a different analysis for this activity. Activities associated with Phase 2 of the PGL stabilization project, as described previously, have the potential to disturb or displace marine mammals. Specifically, the specified activities may result in take, in the form of Level B harassment (behavioral disturbance) from in-air sounds and visual disturbance. Potential takes could occur if individual marine mammals are present nearby when activity is happening.

No injuries or mortalities are anticipated to occur as a result of the PGL stabilization project and none are authorized. The risk of marine mammal injury, serious injury, or mortality associated with the construction project increases somewhat if disturbances occur during pupping season. These situations present increased potential for mothers and dependent pups to become separated and, if separated pairs do not quickly reunite, the risk of mortality to pups (e.g., through starvation) may increase. Separately, adult male elephant seals may trample elephant seal pups if disturbed, which could potentially result in the injury, serious injury, or mortality of the pups. However, the planned activities will occur outside of the elephant seal pupping season, therefore no elephant seal pups are expected to be present. Although the timing of the activities will partially overlap with harbor seal pupping season, the PGL is not a harbor seal rookery and few pups are anticipated to be encountered during the planned construction. In fact, the daily average of harbor seal pups present at PGL during 2022 construction (June 22–September 1) was just 1.7. Harbor seals are very precocious with only a short period of time in which separation of a mother from a pup could occur. The planned activities will occur late enough in the pupping season that any harbor seal pups present will likely be old enough to keep up with their mother in unlikely event of a stampede or other flushing event. The mitigation measures (*i.e.*, minimum separation

distance, slow approaches, and minimizing vehicle trips to the PGL) generally preclude the possibility of behaviors, such as stampeding, that could result in extended separation of mothers and dependent pups or trampling of pups.

Effects on individuals that are taken by Level B harassment, on the basis of reports in the literature as well as monitoring from other similar activities including phase 1 construction at this site, will likely be limited to reactions such as alerts or movements away from the lighthouse structure, including flushing into the water. Most likely, individuals will simply move away from the acoustic or visual stimulus and be temporarily displaced from the areas. In fact, during the first year of construction at PGL elephant seals were not observed flushing at any point during construction and were only observed moving on 11 occasions. Harbor seals were observed flushing 255 times and moving 322 times, which represents a small fraction (6 percent) of the Level B harassment authorized for the project (BLM 2022).

Monitoring reports from similar activities (e.g., Point Blue Conservation Science, 2020; University of California Santa Cruz Partnership for Interdisciplinary Studies of Coastal Oceans, 2021) have reported no apparently consequential behavioral reactions or long-term effects on marine mammal populations as noted above. Repeated exposures of individuals to relatively low levels of sound and visual disturbance outside of preferred habitat areas are unlikely to significantly disrupt critical behaviors or result in permanent abandonment of the haulout site. Thus, even repeated Level B harassment of some small subset of the overall stock is unlikely to result in any significant realized decrease in viability for the affected individuals, and thus will not result in any adverse impact to the stock as a whole. Level B harassment will be reduced to the level of least practicable adverse impact through use of mitigation measures described herein and, if sound and visual disturbance produced by project activities is sufficiently disturbing, animals are likely to simply avoid the area while the activity is occurring.

Of the marine mammal species anticipated to occur in the planned activity areas, none are listed under the ESA and there are no known areas of biological importance in the project area. Taking into account the planned mitigation measures, effects to marine mammals are generally expected to be restricted to short-term changes in behavior or temporary displacement

from haulout sites. The Lost Coast area has abundant haulout areas for pinnipeds to temporarily relocate, and marine mammals are expected to return to the area shortly after activities cease. No adverse effects to prey species are anticipated as no work will occur in-water, and habitat impacts are limited and highly localized, consisting of construction work at the existing lighthouse station and the transit of vehicles and equipment along the access route. Based on the analysis contained herein of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the planned mitigation and monitoring measures, NMFS finds that the total marine mammal take from BLM's PGL stabilization project will not adversely affect annual rates of recruitment or survival and, therefore, will have a negligible impact on the affected species or stocks.

In summary and as described above, the following factors primarily support our determination that the impacts resulting from this activity are not expected to adversely affect any of the species or stocks through effects on annual rates of recruitment or survival:

- No serious injury or mortality, or Level A harassment is anticipated or authorized;
- Few pups are expected to be disturbed, and will not be abandoned or otherwise harmed by other seals flushing from the area;
- Effects of the activities will be limited to short-term, localized behavioral changes;
- Nominal impacts to pinniped habitat are anticipated
- No biologically important areas have been identified in the project area;
- There is abundant suitable habitat nearby for marine mammals to temporarily relocate; and
- Mitigation measures are anticipated to be effective in minimizing the number and severity of takes by Level B harassment, which are expected to be of short duration.

Based on the analysis contained herein of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the planned monitoring and mitigation measures, NMFS finds that the total marine mammal take from the planned activity will have a negligible impact on all affected marine mammal species or stocks.

Small Numbers

As noted previously, only take of small numbers of marine mammals may

be authorized under section 101(a)(5)(A) and (D) of the MMPA for specified activities other than military readiness activities. The MMPA does not define small numbers and so, in practice, where estimated numbers are available, NMFS compares the number of individuals taken to the most appropriate estimation of abundance of the relevant species or stock in our determination of whether an authorization is limited to small numbers of marine mammals. When the predicted number of individuals to be taken is fewer than one-third of the species or stock abundance, the take is considered to be of small numbers. Additionally, other qualitative factors may be considered in the analysis, such as the temporal or spatial scale of the activities.

With the exception of Pacific harbor seals, the amount of take NMFS proposes to authorize is well below one-third of any stock's best population estimate (see Table 4), which NMFS considers to be small relative to stock abundance. In fact, the annual take by Level B harassment is less than 1 percent of stock abundance for both otariid species that may be encountered in the project area (*i.e.*, California sea lion and Steller sea lion), and less than 4 percent of the northern elephant seal stock's best population estimate. While the estimated take of Pacific harbor seal equates to over 33 percent of the Pacific harbor seal stock, these takes represent instances of take, not necessarily the number of individual seals that may be taken. As such, in all cases, including Pacific harbor seal, these take estimates are considered conservative because NMFS assumes all takes are of different individual animals which is likely not the case. Researchers from HSU have used tags and dye stamps to identify individual elephant seals and have verified the same individuals are hauling out at PGL. While harbor seals are not marked or otherwise clearly identifiable, HSU researchers hypothesize that the harbor seal colony at PGL is made up of the same individuals that move between Punta Gorda and other nearby haulouts. This is based on the fact that this species typically shows hauling site fidelity (Herder 1986, Yochem *et al.*, 1987, Dietz *et al.*, 2012, Waring *et al.*, 2016). Therefore, many individuals that may be taken by Level B harassment are likely to be the same across consecutive days, despite PSOs counting them as separate takes throughout the duration of the project.

Based on the analysis contained herein of the authorized activity (including mitigation and monitoring

measures) and the anticipated take of marine mammals, NMFS finds that small numbers of marine mammals will be taken relative to the population size of the affected species or stocks.

Unmitigable Adverse Impact Analysis and Determination

There are no relevant subsistence uses of the affected marine mammal stocks or species implicated by this action. Therefore, NMFS has determined that the total taking of affected species or stocks will not have an unmitigable adverse impact on the availability of such species or stocks for taking for subsistence purposes.

Endangered Species Act

Section 7(a)(2) of the Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*) requires that each Federal agency insure that any action it authorizes, funds, or carries out 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. To ensure ESA compliance for the issuance of IHAs, NMFS consults internally whenever we propose to authorize take for endangered or threatened species, in this case with the West Coast Regional Office.

No incidental take of ESA-listed species is authorized or expected to result from this activity. Therefore, NMFS has determined that formal consultation under section 7 of the ESA is not required for this action.

National Environmental Policy Act

To comply with the National Environmental Policy Act of 1969 (NEPA; 42 U.S.C. 4321 *et seq.*) and NOAA Administrative Order (NAO) 216-6A, NMFS must review our proposed action (*i.e.*, the issuance of an IHA) with respect to potential impacts on the human environment.

This action is consistent with categories of activities identified in Categorical Exclusion B4 (IHAs with no anticipated serious injury or mortality) of the Companion Manual for NOAA Administrative Order 216-6A, which do not individually or cumulatively have the potential for significant impacts on the quality of the human environment and for which we have not identified any extraordinary circumstances that will preclude this categorical exclusion. Accordingly, NMFS has determined that the issuance of the IHA qualifies to be categorically excluded from further NEPA review.

Authorization

NMFS has issued an IHA to BLM for the potential harassment of small numbers of four marine mammal species incidental to the Phase 2 of the PGL Stabilization Project repair in Humboldt County, California from June 1 through September 30, 2023, that includes the previously explained mitigation, monitoring, and reporting requirements.

Dated: May 10, 2023.

Kimberly Damon-Randall,

*Director, Office of Protected Resources,
National Marine Fisheries Service.*

[FR Doc. 2023-10640 Filed 5-17-23; 8:45 am]

BILLING CODE 3510-22-P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648-XC814]

Fisheries of the Exclusive Economic Zone Off Alaska; Prohibited Species Donation Program

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; selection of an authorized distributor.

SUMMARY: NMFS announces the renewal of two prohibited species donation (PSD) permits to SeaShare, a non-profit and tax exempt organization, authorizing this organization to distribute Pacific salmon and Pacific halibut to hunger relief agencies, food bank networks, or food bank distributors under the PSD program. Salmon and halibut are caught incidentally during directed fishing for groundfish with trawl gear off Alaska. This action is necessary to comply with provisions of the PSD program and is intended to promote the goals and objectives of the North Pacific Fishery Management Council.

DATES: The permits are effective from May 18, 2023 through May 25, 2026.

ADDRESSES: Electronic copies of the PSD permits for salmon and halibut prepared for this action may be obtained from the Alaska Region website at <https://www.fisheries.noaa.gov/region/alaska>.

FOR FURTHER INFORMATION CONTACT: Megan Mackey, 907-586-7228.

SUPPLEMENTARY INFORMATION:

Background

Fishing for groundfish by United States vessels in the exclusive economic

zone of the Bering Sea and Aleutian Islands management area (BSAI) and Gulf of Alaska (GOA) is managed by NMFS in accordance with the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area (BSAI FMP) and the Fishery Management Plan for Groundfish of the Gulf of Alaska (GOA FMP). These fishery management plans (FMPs) were prepared by the North Pacific Fishery Management Council under the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1801 *et seq.*). Regulations governing the Alaska groundfish fisheries and implementing the FMPs appear at 50 CFR parts 600 and 679. Fishing for halibut in waters in and off Alaska is governed by the Convention between the U.S. and Canada for the Preservation of the Halibut Fishery of the North Pacific Ocean and Bering Sea (Convention). The International Pacific Halibut Commission (IPHC) promulgates regulations pursuant to the Convention. The IPHC's regulations are subject to approval by the Secretary of State with concurrence from the Secretary of Commerce. After approval by the Secretary of State and the Secretary of Commerce, the IPHC regulations are published in the **Federal Register** as annual management measures pursuant to 50 CFR 300.62.

Retention of incidentally caught prohibited species is prohibited in the groundfish fisheries except for salmon and halibut for the purposes of the PSD program. Amendments 26 and 29 to the BSAI and GOA FMPs, respectively, authorize a salmon donation program and were approved by NMFS on July 10, 1996; a final rule implementing this program was published in the **Federal Register** on July 24, 1996 (61 FR 38358). The salmon donation program was expanded to include halibut as part of the PSD program under Amendments 50 and 50 to the FMPs that were approved by NMFS on May 6, 1998. A final rule implementing Amendments 50 and 50 was published in the **Federal Register** on June 12, 1998 (63 FR 32144). Although that final rule contained a

sunset provision for the halibut PSD program of December 31, 2000, the halibut PSD program was permanently extended under a final rule published in the **Federal Register** on December 14, 2000 (65 FR 78119). A full description of, and background information on, the PSD program may be found in the preambles to the proposed rules for Amendments 26 and 29, and Amendments 50 and 50 (61 FR 24750, May 16, 1996, and 63 FR 10583, March 4, 1998, respectively).

Section 679.26 authorizes the voluntary distribution of salmon and halibut taken incidentally in the groundfish trawl fisheries off Alaska to hunger relief agencies, food bank networks, or food bank distributors by tax-exempt organizations through an authorized distributor. The Administrator, Alaska Region, NMFS (Regional Administrator), may select one or more tax-exempt organizations to be authorized distributors, as defined by § 679.2, based on the information submitted by applicants under § 679.26. After review of qualified applicants, NMFS must announce the selection of each authorized distributor in the **Federal Register** and issue one or more PSD permits to each selected distributor.

Renewal of Permits to SeaShare

Currently, SeaShare, a tax-exempt organization founded to help the seafood industry donate to U.S. hunger relief efforts, is the sole authorized distributor of salmon and halibut taken incidentally in the groundfish trawl fisheries off Alaska. SeaShare's current salmon and halibut PSD permits became effective June 2, 2020, and authorize SeaShare to participate in the PSD program through May 28, 2023 (85 FR 33633, June 2, 2020).

On April 12, 2023, the Regional Administrator received applications from SeaShare to renew its salmon and halibut PSD permits. The Regional Administrator reviewed the applications (one for salmon and one for halibut) and determined that both applications are complete and that SeaShare continues

to meet the requirements for an authorized distributor of salmon and halibut under the PSD program. As required by § 679.26(b)(2), the Regional Administrator based his selection on the following criteria:

1. *The number and qualifications of applicants for PSD permits.* SeaShare is the only applicant for PSD permits at this time. NMFS, under the Regional Administrator, has previously approved applications submitted by SeaShare. As of the date of this notice, no other applications have been approved by NMFS. SeaShare has been coordinating the distribution of salmon taken incidentally in trawl fisheries since 1993, and of halibut taken incidentally in trawl fisheries since 1998, under exempted fishing permits from 1993 to 1996 and under the PSD program since 1996. SeaShare employs independent seafood quality control experts to ensure product quality is maintained by cold storage facilities and common carriers servicing the areas where salmon and halibut donations would take place.

2. *The number of harvesters and the quantity of fish that applicants can effectively administer.* Current participants in the PSD program administered by SeaShare include 12 shoreside processors and 136 catcher vessels delivering to shoreside processors, 34 catcher processors, and 3 motherships. Two secondary processing plants that generate steaked salmon and halibut participate in the PSD program. SeaShare has the capacity to receive and distribute salmon and halibut from up to 60 processors and the associated catcher vessels. Therefore, it is anticipated that SeaShare has more than adequate capacity for any foreseeable expansion of donations.

Table 1 shows the total pounds of headed-and-gutted and steaked salmon and halibut donated to food bank organizations from 2019 through early April of 2023. NMFS does not have information to convert accurately the net weights of salmon and halibut to numbers of salmon and numbers of halibut.

TABLE 1—HEADED-AND-GUTTED (H&G) AND STEAKED SALMON AND HALIBUT DONATED TO FOOD BANK ORGANIZATIONS [Pounds]

	2019	2020	2021	2022	2023	Total
Salmon H&G	3,293	2,150	0.00	292	0.00	5,735
Salmon steaked	368,650	234,520	136,700	181,682	47,051	968,603
Halibut H&G	35,895	19,693	4,100	3,643	0.00	63,331
Halibut steaked	14,313	11,336	9,852	12,1678	1,200	49,379
Total Inventory	422,151	267,699	150,652	198,295	48,251	1,087,048

3. *The anticipated level of salmon and halibut incidental catch based on salmon and halibut incidental catch*

from previous years. The incidental catch of salmon and incidental catch mortality of halibut in the GOA and

BSAI trawl fisheries are shown in Table 2.

TABLE 2—INCIDENTAL CATCH OF SALMON AND INCIDENTAL CATCH MORTALITY OF HALIBUT IN THE GOA AND BSAI TRAWL FISHERIES

[In number of fish or metric tons (mt)]

Area fishery	2019	2020	2021	2022
BSAI Trawl Chinook Salmon Incidental Catch ¹ .	31,467 fish	34,955 fish	15,880 fish	8,336 fish
BSAI Trawl Other Salmon Incidental Catch ² .	358,804 fish	346,245 fish	550,645 fish	245,160 fish
GOA Trawl Chinook Salmon Incidental Catch ³ .	23,903 fish	11,753 fish	17,180 fish	14,565 fish
GOA Trawl Other Salmon Incidental Catch ⁴ .	6,413 fish	3,232 Fish	3,566 Fish	5,241 Fish
BSAI Trawl Halibut Mortality ⁵	2,270 mt	1,577 mt	1,426 mt	2,057 mt
GOA Trawl Halibut Mortality ⁶	1,099 mt	788 mt	367 mt	353 mt

¹ https://www.fisheries.noaa.gov/sites/default/files/akro/chinook_salmon_mortality2023.html.

² https://www.fisheries.noaa.gov/sites/default/files/akro/chum_salmon_mortality2023.html.

³ <https://www.fisheries.noaa.gov/sites/default/files/akro/goasalmonmort2023.html>.

⁴ https://www.fisheries.noaa.gov/sites/default/files/akro/chum_salmon_mortality2023.html.

⁵ <https://www.fisheries.noaa.gov/alaska/commercial-fishing/fisheries-catch-and-landings-reports#bsai-prohibited-species>.

⁶ <https://www.fisheries.noaa.gov/alaska/commercial-fishing/fisheries-catch-and-landings-reports#goa-prohibited-species>.

Halibut incidental catch amounts are constrained by an annual prohibited species catch (PSC) limit in the BSAI and GOA. Future halibut incidental catch levels likely will be similar to those experienced from 2019 through 2022.

Chinook salmon PSC limits (which are in number of fish) are established for the Bering Sea and central and western GOA pollock fisheries that, when attained, result in the closure of pollock fishing. The Chinook salmon PSC limits for the Bering Sea pollock fisheries were originally established by Amendment 91 to the BSAI FMP (75 FR 53026, August 30, 2010) and established for the central and western GOA pollock fisheries by Amendment 93 to the GOA FMP (77 FR 42629, July 20, 2012). In 2016, Amendment 110 to the BSAI FMP was implemented to improve the management of Chinook and chum salmon bycatch in the Bering Sea pollock fishery by creating a comprehensive salmon bycatch avoidance program (81 FR 37534, June 10, 2016). In 2015, Amendment 97 to the GOA FMP established annual Chinook salmon PSC limits for the groundfish trawl fisheries, except for pollock trawl fisheries, in the Western and Central GOA (79 FR 71350, December 2, 2014). While salmon incidental catch amounts tend to vary between years, making it difficult to accurately predict future incidental take amounts, the total, or maximum, amount of annual Chinook salmon incidental catch in the Bering Sea and GOA pollock fisheries is constrained by the PSC limits.

4. *The number of vessels and processors participating in the PSD program.* For the 2023 permit renewal, there will be 12 shoreside processors. Catcher processors will decrease from 34 to 31 under the 2023 permit renewal. Motherships will increase from three to four. Catcher vessels delivering to shoreside processors as well as motherships will decrease slightly from 151 to 140. Secondary processors will increase from two to three.

NMFS issues PSD permits to SeaShare for a 3-year period unless the permits are suspended or revoked under § 679.26. The permits may not be transferred; however, they may be renewed following the application procedures in § 679.26. If the authorized distributor modifies the list of participants in the PSD program or delivery locations, the authorized distributor must submit a modified list of participants or a modified list of delivery locations to the Regional Administrator within 30 days of the list modification.

These permits may be suspended, modified, or revoked under 15 CFR part 904 for violation of § 679.26 or other regulations in 50 CFR part 679.

This action is taken under § 679.26.

Authority: 16 U.S.C. 773 *et seq.*; 1801 *et seq.*; 3631 *et seq.*; Pub. L. 108–447; Pub. L. 111–281.

Dated: May 12, 2023.

Jennifer M. Wallace,
Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.
[FR Doc. 2023–10570 Filed 5–17–23; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC916]

Takes of Marine Mammals Incidental to Specified Activities; Taking Marine Mammals Incidental to the Chevron Long Wharf Maintenance and Efficiency Project in San Francisco Bay, California

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of incidental harassment authorization.

SUMMARY: In accordance with the regulations implementing the Marine Mammal Protection Act (MMPA) as amended, notification is hereby given the NMFS has issued an incidental harassment authorization (IHA) to Chevron Products Company (Chevron) to incidentally harass, by Level B harassment only, marine mammals during construction activities associated with the Long Wharf Maintenance and Efficiency Project (LWMEP) in San Francisco Bay, California.

DATES: This authorization is effective from June 1, 2023 through May 31, 2024.

FOR FURTHER INFORMATION CONTACT:

Jessica Taylor, Office of Protected Resources, NMFS, (301) 427–8401. Electronic copies of the application and supporting documents, as well as a list of the references cited in this document,

may be obtained online at: <https://www.fisheries.noaa.gov/national/marine-mammal-protection/incidental-take-authorizations-construction-activities>. In case of problems accessing these documents, please call the contact listed above.

SUPPLEMENTARY INFORMATION:

Background

The MMPA prohibits the “take” of marine mammals, with certain exceptions. Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce (as delegated to NMFS) to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are proposed or, if the taking is limited to harassment, a notice of a proposed IHA is provided to the public for review.

Authorization for incidental takings shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s) and will not have an unmitigable adverse impact on the availability of the species or stock(s) for taking for subsistence uses (where relevant). Further, NMFS must prescribe the permissible methods of taking and other “means of effecting the least practicable adverse impact” on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stocks for taking for certain subsistence uses (referred to in shorthand as “mitigation”); and requirements pertaining to the mitigation, monitoring and reporting of the takings are set forth. The definitions of all applicable MMPA statutory terms cited above are included in the relevant sections below.

Summary of Request

On December 16, 2022, NMFS received a request from Chevron Products Company (Chevron) for an IHA to take marine mammals incidental to pile driving activities associated with the LWMEP in San Francisco Bay (the Bay), California. Following NMFS’ review of the application, Chevron submitted a final revised version on February 27, 2023. The application was deemed adequate and complete on March 20, 2023. Chevron’s request is for take of 7 species of marine mammals by Level B harassment only. Neither Chevron nor NMFS expect serious injury or mortality to result from this

activity and, therefore, an IHA is appropriate.

NMFS previously issued IHAs to Chevron for similar work (83 FR 27548, June 13, 2018; 84 FR 28474, June 19, 2019; 85 FR 37064, June 19, 2020; 86 FR 28578, May 27, 2021; 87 FR 35180, June 9, 2022). Chevron complied with all the requirements (*e.g.*, mitigation, monitoring, and reporting) of the previous IHAs, and information regarding their monitoring results may be found in the Estimated Take section.

The IHA will cover 1 year of a larger project for which Chevron obtained prior IHAs and intends to request take authorization for subsequent facets of the project. The larger 5-year project involves upgrading Long Wharf to satisfy current Marine Oil Terminal Engineering and Maintenance Standards.

There are no changes from the proposed IHA to the final IHA.

Description of Activity

Overview

Chevron plans to upgrade Berth 1 of the Refinery Long Wharf in the Bay, California in order to meet current safety and efficiency standards. As part of the project, Chevron will use vibratory extraction to remove concrete piles associated with the existing gangway and catwalk. Impact hammers will be used to install concrete piles to construct a mooring dolphin and hook, breasting dolphin and breasting points with standoff fenders, and to replace the catwalk in a different location. A temporary construction template composed of steel piles will be installed through the use of a vibratory hammer and removed by vibratory extraction when in-water construction activities are complete. The Long Wharf has six berths for receiving raw materials and shipping products. The project area encompasses the entirety of Berth 1, an area of approximately 470 square meters (m²). All in-water work will take place within the seasonal work window of June 1, 2023 through November 30, 2023. Unless otherwise specified, the term “pile driving” may refer to either pile installation or removal.

Chevron’s activity includes impact and vibratory pile driving and vibratory pile removal, which may result in the incidental take of marine mammals, by harassment only. Due to mitigation measures, no Level A harassment is anticipated to occur, and none is authorized.

A detailed description of the planned construction project is provided in the **Federal Register** notice for the proposed IHA (88 FR 19247, March 31, 2023).

Since that time, no changes have been made to the planned construction activities. Therefore, a detailed description is not provided here. Please refer to that **Federal Register** notice for a description of the specific activity. Mitigation, monitoring, and reporting measures are described in detail later in this document (please see Mitigation and Monitoring and Reporting).

Comments and Responses

A notice of NMFS’ proposal to issue an IHA to Chevron was published in the **Federal Register** on March 31, 2023 (88 FR 19237). That notice described, in detail, Chevron’s activity, the marine mammal species that may be affected by the activity, and the anticipated effects on marine mammals. In that notice, we requested public input on the request for authorization described therein, our analyses, the proposed authorization, and any other aspect of the notice of proposed IHA, and requested that interested persons submit relevant information, suggestions, and comments. During the 30-day public comment period, NMFS did not receive any public comments.

Description of Marine Mammals in the Area of Specified Activities

Sections 3 and 4 of the application summarize available information regarding status and trends, distribution and habitat preferences, and behavior and life history of the potentially affected species. NMFS fully considered all of this information, and we refer the reader to these descriptions, instead of reprinting the information. Additional information regarding population trends and threats may be found in NMFS’ Stock Assessment Reports (SARs; www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments) and more general information about these species (*e.g.*, physical and behavioral descriptions) may be found on NMFS’ website (<https://www.fisheries.noaa.gov/find-species>).

Table 1 lists all species or stocks for which take is expected and authorized for this activity, and summarizes information related to the population or stock, including regulatory status under the MMPA and Endangered Species Act (ESA) and potential biological removal (PBR), where known. PBR is defined by the MMPA as the maximum number of animals, not including natural mortalities, that may be removed from a marine mammal stock while allowing that stock to reach or maintain its optimum sustainable population (as described in NMFS’ SARs). While no serious injury or mortality is anticipated

or authorized here, PBR and annual serious injury and mortality from anthropogenic sources are included here as gross indicators of the status of the species or stocks and other threats.

Marine mammal abundance estimates presented in this document represent the total number of individuals that make up a given stock or the total

number estimated within a particular study or survey area. NMFS' stock abundance estimates for most species represent the total estimate of individuals within the geographic area, if known, that comprises that stock. For some species, this geographic area may extend beyond U.S. waters. All managed stocks in this region are assessed in

NMFS' U.S. Pacific SARs. All values presented in Table 1 are the most recent available at the time of publication (including from the draft 2022 SARs) and are available online at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments.

TABLE 1—MARINE MAMMAL SPECIES ⁴ LIKELY TO BE IMPACTED BY THE SPECIFIED ACTIVITIES

Common name	Scientific name	Stock	ESA/MMPA status; strategic (Y/N) ¹	Stock abundance (CV, N _{min} , most recent abundance survey) ²	PBR	Annual M/SI ³
Order Artiodactyla—Infraorder Cetacea—Mysticeti (baleen whales)						
Family Eschrichtiidae: Gray whale	<i>Eschrichtius robustus</i> .	Eastern North Pacific.	-, -, N	26,960 (0.05, 25,849, 2016).	801	131
Odontoceti (toothed whales, dolphins, and porpoises)						
Family Delphinidae: Bottlenose dolphin.	<i>Tursiops truncatus</i>	California Coastal ..	-, -, N	453 (0.06, 346, 2011).	2.7	≥2.0
Family Phocoenidae (porpoises): Harbor porpoise	<i>Phocoena phocoena</i> .	San Francisco/Russian River.	-, -, N	7,777 (0.62, 4,811, 2017).	73	≥0.4
Order Carnivora—Pinnipedia						
Family Otariidae (eared seals and sea lions): California sea lion.	<i>Zalophus californianus</i> .	U.S.	-, -, N	257,606 (N/A, 233,515, 2014).	14,011	>321
Northern fur seal ⁵ .	<i>Callorhinus ursinus</i>	California	-, D, N	14,050 (N/A, 7,524, 2013).	451	1.8
Family Phocidae (earless seals): Harbor seals	<i>Phoca vitulina</i>	California	-, -, N	30,968 (N/A, 27,348, 2012).	1,641	43
Northern elephant seal.	<i>Mirounga angustirostris</i> .	California Breeding	-, -, N	187,386 (N/A, 85,369, 2013).	5,122	13.7

¹ Endangered Species Act (ESA) status: Endangered (E), Threatened (T)/MMPA status: Depleted (D). A dash (-) indicates that the species is not listed under the ESA or designated as depleted under the MMPA. Under the MMPA, a strategic stock is one for which the level of direct human-caused mortality exceeds PBR or which is determined to be declining and likely to be listed under the ESA within the foreseeable future. Any species or stock listed under the ESA is automatically designated under the MMPA as depleted and as a strategic stock.

² NMFS marine mammal stock assessment reports online at: <https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments/>. CV is coefficient of variation; N_{min} is the minimum estimate of stock abundance. In some cases, CV is not applicable as in the case of the pinnipeds, as population estimates are dependent upon the numbers of individuals hauled out or the number of pups.

³ These values, found in NMFS's SARs, represent annual levels of human-caused mortality plus serious injury from all sources combined (e.g., commercial fisheries, ship strike). Annual M/SI often cannot be determined precisely and is in some cases presented as a minimum value or range. A CV associated with estimated mortality due to commercial fisheries is presented in some cases.

⁴ Information on the classification of marine mammal species can be found on the web page for The Society for Marine Mammalogy's Committee on Taxonomy (<https://marinemammalscience.org/science-and-publications/list-marine-mammal-species-subspecies/>; Committee on Taxonomy (2022)).

⁵ Survey years = Sea Lion Rock—2014; St. Paul and St. George Is.—2014, 2016, 2018; Bogoslof Is.—2015, 2019.

As indicated above, all seven species (with seven managed stocks) in Table 2 temporally and spatially co-occur with the activity to the degree that take is reasonably likely to occur. All species that could potentially occur in the project area are included in Table 4–1 of the IHA application. While humpback whales have been sighted in the coastal waters outside of the Bay,

the spatial occurrence of this species is such that take is not expected to occur, and they are not discussed further beyond the explanation provided here. Although there are no published studies available regarding the distribution of humpback whales in the Bay, sightings from whale watching vessels and other mariners report that when humpback whales enter the Bay, they rarely move

east into the Bay towards the vicinity of the project area and are unlikely to occur during the activities.

A detailed description of the species likely to be affected by the pile driving activities, including brief introductions to the species and relevant stocks as well as available information regarding population trends and threats, and information regarding local occurrence,

were provided in the **Federal Register** notice for the proposed IHA (88 FR 19247, March 31, 2023); since that time, we are not aware of any changes in the status of these species and stocks; therefore, detailed descriptions are not provided here. Please refer to that **Federal Register** notice for these descriptions. Please also refer to NMFS' website (<https://www.fisheries.noaa.gov/find-species>) for generalized species accounts.

Marine Mammal Hearing

Hearing is the most important sensory modality for marine mammals underwater, and exposure to anthropogenic sound can have

deleterious effects. To appropriately assess the potential effects of exposure to sound, it is necessary to understand the frequency ranges marine mammals are able to hear. Not all marine mammal species have equal hearing capabilities (*e.g.*, Richardson *et al.*, 1995; Wartzok and Ketten, 1999; Au and Hastings, 2008). To reflect this, Southall *et al.* (2007, 2019) recommended that marine mammals be divided into hearing groups based on directly measured (behavioral or auditory evoked potential techniques) or estimated hearing ranges (behavioral response data, anatomical modeling, *etc.*). Note that no direct measurements of hearing ability have

been successfully completed for mysticetes (*i.e.*, low-frequency cetaceans). Subsequently, NMFS (2018) described generalized hearing ranges for these marine mammal hearing groups. Generalized hearing ranges were chosen based on the approximately 65 decibel (dB) threshold from the normalized composite audiograms, with the exception for lower limits for low-frequency cetaceans where the lower bound was deemed to be biologically implausible and the lower bound from Southall *et al.* (2007) retained. Marine mammal hearing groups and their associated hearing ranges are provided in Table 2.

TABLE 2—MARINE MAMMAL HEARING GROUPS
[NMFS, 2018]

Hearing group	Generalized hearing range *
Low-frequency (LF) cetaceans (baleen whales)	7 Hz to 35 kHz.
Mid-frequency (MF) cetaceans (dolphins, toothed whales, beaked whales, bottlenose whales)	150 Hz to 160 kHz.
High-frequency (HF) cetaceans (true porpoises, <i>Kogia</i> , river dolphins, Cephalorhynchid, <i>Lagenorhynchus cruciger</i> & <i>L. australis</i>).	275 Hz to 160 kHz.
Phocid pinnipeds (PW) (underwater) (true seals)	50 Hz to 86 kHz.
Otariid pinnipeds (OW) (underwater) (sea lions and fur seals)	60 Hz to 39 kHz.

* Represents the generalized hearing range for the entire group as a composite (*i.e.*, all species within the group), where individual species' hearing ranges are typically not as broad. Generalized hearing range chosen based on ~65 dB threshold from normalized composite audiogram, with the exception for lower limits for LF cetaceans (Southall *et al.*, 2007) and PW pinniped (approximation).

The pinniped functional hearing group was modified from Southall *et al.* (2007) on the basis of data indicating that phocid species have consistently demonstrated an extended frequency range of hearing compared to otariids, especially in the higher frequency range (Hemilä *et al.*, 2006; Kastelein *et al.*, 2009; Reichmuth and Holt, 2013).

For more detail concerning these groups and associated frequency ranges, please see NMFS (2018) for a review of available information.

Potential Effects of Specified Activities on Marine Mammals and Their Habitat

The effects of underwater noise from Chevron's pile driving activities have the potential to result in behavioral harassment of marine mammals in the vicinity of the project area. The notice of the proposed IHA (88 FR 19247, March 31, 2023) included a discussion of the effects of anthropogenic noise on marine mammals and the potential effects of underwater noise from Chevron's pile driving activities on marine mammals and their habitat. That information and analysis is incorporated by reference into this final IHA determination and is not repeated here; please refer to the notice of the proposed IHA (88 FR 19247, March 31, 2023).

Estimated Take of Marine Mammals

This section provides an estimate of the number of incidental takes authorized through this IHA, which informed both NMFS' consideration of "small numbers," and the negligible impact determinations.

Harassment is the only type of take expected to result from these activities. Except with respect to certain activities not pertinent here, section 3(18) of the MMPA defines "harassment" as any act of pursuit, torment, or annoyance, which (i) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment); or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment).

Authorized takes would be by Level B harassment only, in the form of disruption of behavioral patterns for individual marine mammals resulting from exposure to the acoustic sources. Based on the nature of the activity and the anticipated effectiveness of the mitigation measures (*i.e.*, shutdown zones, protected species observers (PSOs) monitoring) discussed in detail

below in the Mitigation section, Level A harassment is neither anticipated nor authorized.

As described previously, no serious injury or mortality is anticipated or authorized for this activity. Below, we describe how the take numbers are estimated.

For acoustic impacts, generally speaking, we estimate take by considering: (1) acoustic thresholds above which NMFS believes the best available science indicates marine mammals will be behaviorally harassed or incur some degree of permanent hearing impairment; (2) the area or volume of water that will be ensonified above these levels in a day; (3) the density or occurrence of marine mammals within these ensonified areas; and (4) the number of days of activities. We note that while these factors can contribute to a basic calculation to provide an initial prediction of potential takes, additional information that can qualitatively inform take estimates is also sometimes available (*e.g.*, previous monitoring results or average group size). Below, we describe the factors considered here in more detail and present the take estimates.

Acoustic Thresholds

NMFS recommends the use of acoustic thresholds that identify the received level of underwater sound above which exposed marine mammals would be reasonably expected to be behaviorally harassed (equated to Level B harassment) or to incur permanent threshold shift (PTS) of some degree (equated to Level A harassment).

Level B Harassment—Though significantly driven by received level, the onset of behavioral disturbance from anthropogenic noise exposure is also informed to varying degrees by other factors related to the source or exposure context (e.g., frequency, predictability, duty cycle, duration of the exposure, signal-to-noise ratio, distance to the source), the environment (e.g., bathymetry, other noises in the area, predators in the area), and the receiving animals (hearing, motivation, experience, demography, life stage, depth) and can be difficult to predict (e.g., Southall *et al.*, 2007, 2021; Ellison *et al.*, 2012). Based on what the available science indicates and the practical need to use a threshold based on a metric that is both predictable and measurable for most activities, NMFS typically uses a generalized acoustic

threshold based on received level to estimate the onset of behavioral harassment. NMFS generally predicts that marine mammals are likely to be behaviorally harassed in a manner considered to be Level B harassment when exposed to underwater anthropogenic noise above RMS pressure received levels (SPL) of 120 dB (referenced to 1 micropascal (re 1 μ Pa)) for continuous (e.g., vibratory pile-driving, drilling) and above RMS SPL 160 dB re 1 μ Pa for non-explosive impulsive (e.g., seismic airguns) or intermittent (e.g., scientific sonar) sources. Generally speaking, Level B harassment take estimates based on these behavioral harassment thresholds are expected to include any likely takes by temporary threshold shift (TTS) as, in most cases, the likelihood of TTS occurs at distances from the source less than those at which behavioral harassment is likely. TTS of a sufficient degree can manifest as behavioral harassment, as reduced hearing sensitivity and the potential reduced opportunities to detect important signals (conspecific communication, predators, prey) may result in changes in behavior patterns that would not otherwise occur.

Chevron's pile driving activities include the use of continuous (vibratory pile-driving) and impulsive (impact pile-driving) sources, and therefore the RMS SPL thresholds of 120 and 160 dB re 1 μ Pa are applicable.

Level A harassment—NMFS' Technical Guidance for Assessing the Effects of Anthropogenic Sound on Marine Mammal Hearing (Version 2.0) (Technical Guidance, 2018) identifies dual criteria to assess auditory injury (Level A harassment) to five different marine mammal groups (based on hearing sensitivity) as a result of exposure to noise from two different types of sources (impulsive or non-impulsive). Chevron's pile driving activities include the use of impulsive (impact hammer) and non-impulsive (vibratory hammer) sources.

These thresholds are provided in the table below. The references, analysis, and methodology used in the development of the thresholds are described in NMFS' 2018 Technical Guidance, which may be accessed at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-acoustic-technical-guidance.

TABLE 3—THRESHOLDS IDENTIFYING THE ONSET OF PERMANENT THRESHOLD SHIFT

Hearing group	PTS onset thresholds* (received level)	
	Impulsive	Non-impulsive
Low-Frequency (LF) Cetaceans	Cell 1: $L_{p,0-pk,flat}$: 219 dB; $L_{E,p,LF,24h}$: 183 dB	Cell 2: $L_{E,p,LF,24h}$: 199 dB.
Mid-Frequency (MF) Cetaceans	Cell 3: $L_{p,0-pk,flat}$: 230 dB; $L_{E,p,MF,24h}$: 185 dB	Cell 4: $L_{E,p,MF,24h}$: 198 dB.
High-Frequency (HF) Cetaceans	Cell 5: $L_{p,0-pk,flat}$: 202 dB; $L_{E,p,HF,24h}$: 155 dB	Cell 6: $L_{E,p,HF,24h}$: 173 dB.
Phocid Pinnipeds (PW) (Underwater)	Cell 7: $L_{p,0-pk,flat}$: 218 dB; $L_{E,p,PW,24h}$: 185 dB	Cell 8: $L_{E,p,PW,24h}$: 201 dB.
Otariid Pinnipeds (OW) (Underwater)	Cell 9: $L_{p,0-pk,flat}$: 232 dB; $L_{E,p,OW,24h}$: 203 dB	Cell 10: $L_{E,p,OW,24h}$: 219 dB.

*Dual metric thresholds for impulsive sounds: Use whichever results in the largest isopleth for calculating PTS onset. If a non-impulsive sound has the potential of exceeding the peak sound pressure level thresholds associated with impulsive sounds, these thresholds are recommended for consideration.

Note: Peak sound pressure level ($L_{p,0-pk}$) has a reference value of 1 μ Pa, and weighted cumulative sound exposure level ($L_{E,p}$) has a reference value of 1 μ Pa²s. In this Table, thresholds are abbreviated to be more reflective of International Organization for Standardization standards (ISO, 2017). The subscript "flat" is being included to indicate peak sound pressure are flat weighted or unweighted within the generalized hearing range of marine mammals (i.e., 7 Hz to 160 kHz). The subscript associated with cumulative sound exposure level thresholds indicates the designated marine mammal auditory weighting function (LF, MF, and HF cetaceans, and PW and OW pinnipeds) and that the recommended accumulation period is 24 hours. The weighted cumulative sound exposure level thresholds could be exceeded in a multitude of ways (i.e., varying exposure levels and durations, duty cycle). When possible, it is valuable for action proponents to indicate the conditions under which these thresholds will be exceeded.

Ensonified Area

Here, we describe operational and environmental parameters of the activity that are used in estimating the area ensonified above the acoustic thresholds, including source levels and transmission loss coefficient.

Pile driving activities, using an impact hammer as well as a vibratory hammer, will generate underwater noise that could result in disturbance to marine mammals near the project area. A review of underwater sound measurements for similar projects was

conducted to estimate the near-source sound levels for impact and vibratory pile driving and vibratory extraction. Source levels for removal and installation activities derived from this review are shown in Table 4.

TABLE 4—SOURCE LEVELS FOR PILE REMOVAL AND INSTALLATION ACTIVITIES

Method	Pile type	Source levels (dB)/source distance (m)			Reference
		Peak sound pressure (dB re 1 μ Pa)	Mean maximum RMS SPL (dB re 1 μ Pa)	SEL ¹ (dB re 1 μ Pa ² sec)	
Impact install ²	24-inch square concrete pile.	191/10	173/10	161/10	AECOM (2018, 2019).
Vibratory install/extract	36-inch steel shell pile	196/10	167/15	167	AECOM (2019).
Vibratory extract ³	18-inch concrete pile	N/A	163/10	150	NAVFAC SW (2022).

¹ Sound exposure level (SEL).

² Chevron will use a bubble curtain attenuation system for all impact pile driving. NMFS conservatively assumes that the bubble curtain will result in a 5 dB reduction in sound. These source levels incorporate the 5 dB reduction.

³ 20-inch concrete piles used as a proxy as vibratory data for 18-inch concrete piles was not available.

Level B Harassment Zones—
Transmission loss (TL) is the decrease in acoustic intensity as an acoustic pressure wave propagates out from a source. TL parameters vary with frequency, temperature, sea conditions, current, source and receiver depth, water depth, water chemistry, and bottom composition topography. The general formula for underwater TL is:

$$TL = B * \text{Log}_{10} (R_1/R_2),$$

Where

TL = transmission loss in dB;

B = transmission loss coefficient;

R₁ = the distance of the modeled SPL from the driven pile; and

R₂ = the distance from the driven pile of the initial measurement.

The recommended TL coefficient for most nearshore environments is the

practical spreading value of 15. This value results in an expected propagation environment that would lie between spherical and cylindrical spreading loss conditions, known as practical spreading. As is common practice in coastal waters, here we assume practical spreading (4.5 dB reduction in sound level for each doubling of distance) for vibratory extraction of concrete piles, as hydro-acoustic data for the same pile type was not available for this project site. Chevron conducted hydro-acoustic monitoring for prior projects at Long Wharf for the impact driving of 24-inch concrete piles and vibratory driving of 36-inch steel piles. Based upon hydro-acoustic monitoring conducted at Long Wharf in 2018 and 2019 (AECOM, 2018, 2019), Chevron calculated a transmission loss coefficient ranging

from 14 to 20 (~4.4 dB to 8 dB per doubling of distance). As this estimate represents a wide range of measured transmission loss, NMFS applied the standard value of 15 for impact driving of concrete piles. For vibratory driving of 36-inch steel piles, Chevron calculated a transmission loss coefficient of 20.8 to 25.0 (~8 dB to 9 dB per doubling of distance) from hydro-acoustic monitoring conducted at Long Wharf in 2019 (AECOM, 2019). Given that all available data suggested a higher transmission loss, NMFS found it appropriate to apply this to its analysis. NMFS applied the lower of these two values, 20.8 TL, to this analysis to be conservative. The Level B harassment zones and ensonified areas for Chevron's activities are shown in Table 5.

TABLE 5—DISTANCE TO LEVEL B HARASSMENT THRESHOLDS AND ENSONIFIED AREAS

Pile type	Source levels (dB)/source distance (m)		Distance to level B harassment thresholds (m)	Ensonified area (km ²)
	Peak	RMS		
Impact Installation: 24-inch square concrete pile	191/10	173/10	74	0.02
Vibratory Installation: 36-inch steel shell pile	196/10	167/15	2,727	23.36
Vibratory Extraction: 18-inch concrete pile	N/A	163/10	7,356	170
36-inch steel shell pile	196/10	167/15	2,727	17.24

Level A Harassment Thresholds—The ensonified area associated with Level A harassment is more technically challenging to predict due to the need to account for a duration component. Therefore, NMFS developed an optional User Spreadsheet tool to accompany the Technical Guidance that can be used to relatively simply predict an isopleth distance for use in conjunction with marine mammal density or occurrence to help predict potential takes. We note that because of some of the assumptions

included in the methods underlying the optional tool, we anticipate that the resulting isopleth estimates are typically going to be overestimates of some degree, which may result in an overestimate of potential take by Level A harassment. However, this optional tool offers the best way to estimate isopleth distances when more sophisticated modeling methods are not available or practical. For stationary sources, such as pile driving activities, the optional User Spreadsheet tool

predicts the closest distance at which a stationary animal would not be expected to incur PTS if the sound source traveled by the stationary animal in a straight line at a constant speed. The isopleths generated by the User Spreadsheet used the same TL coefficients as the Level B harassment zone calculations, as indicated above for each activity type. Inputs used in the User Spreadsheet (e.g., number of piles per day, duration and/or strikes per pile) are presented in Table 1 of the

Federal Register notice for the proposed IHA (88 FR 19247, March 31, 2023). The maximum RMS SPL/SEL SPL as well as peak SPL and resulting isopleths are

reported below in Table 6. The RMS SPL value was used to calculate Level A harassment isopleths for vibratory pile driving and extraction activities,

while the single strike SEL SPL value was used to calculate Level A isopleths for impact pile driving activity.

TABLE 6—DISTANCE TO LEVEL A HARASSMENT THRESHOLDS FOR EACH MARINE MAMMAL HEARING GROUP

Pile type	Source levels (dB)/source distance (m)		Distances to level A harassment threshold (m)				
	Peak	RMS/SEL	Lf cetaceans	Mf cetaceans	Hf cetaceans	Phocid pinnipeds	Otariid pinnipeds
Impact Installation: 24-inch square concrete pile.	191/10	161/10 SEL ..	31.3	1.1	37.3	16.8	1.2
Vibratory Installation: 36-inch steel shell pile.	196/10	167/15 RMS	15.9	2.8	21	11.1	1.6
Vibratory Extraction: 18-inch concrete pile.	N/A	163/10 RMS	3.4	0.3	5	2.1	0.1
36-inch steel shell pile.	196/10	167/15 RMS	15.9	2.8	21	11.1	1.6

Lf = low frequency, Mf = mid-frequency, Hf = high frequency.

Marine Mammal Occurrence

In this section, we provide information about the occurrence of marine mammals, including density or other relevant information that will inform the take calculations.

Harbor Seal—Limited at-sea densities are available for Pacific harbor seals in the Bay. To estimate the number of harbor seals potentially taken by Level B harassment, take estimates were developed based upon annual surveys of haulouts in the Bay conducted by the National Park Service (NPS) (Codde and Allen 2013, 2015, 2017, 2020; Codde, 2020). Harbor seals spend more time hauled out and enter the water later in the evening during molting season (NPS, 2014). The molting season occurs from June–July and overlaps with the construction period of June–November, therefore, haulout counts may provide the most accurate estimates of harbor seals in the area during that time. Due to the close proximity of Castro Rocks to the project area, Chevron used the highest mean value of harbor seals observed hauled out at Castro Rocks during the molting season in any recent NPS annual survey. The highest mean number of harbor seals was recorded in 2019 as 237 seals. There are no systematic counts available to estimate the number of seals that may be in the water near Long Wharf at any given time and the number of seals hauled out on Castro Rocks may vary based upon time of day, tide, and seal activity. Therefore, the analysis assumes that all 237 seals could swim into the Level B harassment zone each day that pile driving is occurring.

California sea lion—Although there are no haulout sites for California sea lions in close proximity to the project area, sea lions have consistently been sighted in the Bay while monitoring during past construction projects (AECOM, 2019, 2020, 2021, 2022; Caltrans, 2017). As limited data is available on the occurrences of California sea lions in the Bay, NMFS used PSO monitoring data from previous stages of the LWMEP (AECOM, 2019, 2020, 2021) and Year 1 of the Point Orient Wharf Removal (POWR) project (AECOM, 2022) to generate a daily occurrence rate. NMFS calculated daily occurrence rate using the following equation:

Daily occurrence rate = Total number of animals sighted/Total monitoring days.

From 2018–2022, a total of 73 days of monitoring occurred across all projects during the seasonal window of June through November. During this time, 13 sea lions were sighted. Based upon sightings and monitoring days, we calculated a daily occurrence rate of 0.18 sea lions per day.

San Francisco has received a record amount of rainfall since July 1, 2022 (Bay City News, 2023), indicating that increased freshwater inflow into the Bay could be expected this year. The Bay did not experience similar freshwater inflow during the LWMEP and POWR years of 2018–2022. As the impacts of increased freshwater flow into the project area on California sea lion occurrences are unclear, and this increased freshwater input did not occur during prior monitoring years, we conservatively used a daily occurrence

rate of California sea lions, one sea lion per day, to estimate take.

Harbor porpoise—The harbor porpoise population has been growing over time in the Bay (Stern *et al.*, 2017). Although commonly sighted in the vicinity of Angel Island and the Golden Gate Bridge, approximately 6 and 12 kilometers (3.7 and 7.5 miles, respectively) southwest of the Wharf, individuals may use other areas of central the Bay (Keener, 2011), as well as the project area. As limited data is available on the occurrences of harbor porpoises in the Bay, NMFS used PSO monitoring data from previous stages of the LWMEP (AECOM, 2019, 2020, 2021) and Year 1 of the Point Orient Wharf Removal (POWR) project (AECOM, 2022) to generate a daily occurrence rate. NMFS calculated the daily occurrence rate according to the same methods for calculating the daily occurrence rate for California sea lions, as described above. From 2018–2022, a total of 16 harbor porpoises were sighted on 73 monitoring days, resulting in a daily occurrence rate of 0.22 harbor porpoises per day. Due to the impacts of increased freshwater inflow into the Bay (Bay City News, 2023) resulting from elevated rainfall being unclear, we conservatively used a higher daily occurrence rate of harbor porpoises, one porpoise per day, to estimate take.

Gray whale—Gray whales are often sighted in the Bay during February and March, however, pile driving activities are not planned to occur during this time. Prior monitoring reports for similar projects occurring during the same work windows did not document gray whales in the area (AECOM, 2019,

2020, 2021). Limited sightings of gray whales in the Bay include strandings (Bartlett, 2022; TMMC, 2019) and whale watch reports (Bartlett, 2022). At-sea densities and regular observational data for gray whales in the Bay during the planned project time are not available. Although unlikely during the time planned for in-water construction activities, Chevron conservatively estimated that up to two gray whales may occur in the project area.

Bottlenose dolphin—The numbers of dolphins in the Bay have been increasing over the years (Perlman, 2017; Szczepaniak *et al.*, 2013), and a recent study determined that bottlenose dolphins have expanded their range to include coastal waters north and south of the Bay (Keener *et al.*, 2023). In the Bay, dolphins have been sighted in the vicinity of the Golden Gate Bridge, around Yerba Buena and Angel Islands, and in the central Bay as far east as Alameda and Point Richard (Keener *et al.*, 2023). Although dolphins may occur in the Bay year-round, occurrence estimates are limited. Chevron estimated that one group of dolphins may enter the Bay once per month. Weller *et al.* (2016) estimated an average group size for coastal bottlenose dolphins to be approximately 8.2 dolphins.

Northern elephant seal—Small numbers of elephant seals may haul out or strand within the central Bay (Hernández, 2020). Previous monitoring, however, has shown northern elephant seal densities to be very low in the area and, based upon seasonality of occurrences, northern elephant seals would be unlikely to occur in the project area during the project activities. Additionally, northern elephant seals were not observed during pile driving monitoring for the LWMEP from 2018–2021 (AECOM, 2018, 2019, 2020, 2021)

nor for the Point Orient Wharf Removal in 2022 (AECOM, 2022), which was located just north of the project area. While it is unlikely that northern elephant seals would occur in the project area during the months in which work is planned, Chevron conservatively estimated that 1 northern elephant seal could enter the project area once every 3 days during in-water construction activities resulting in a total of 10 northern elephant seals.

Northern fur seal—The presence of northern fur seals in depends upon oceanic conditions, as more fur seals are more likely to range in the Bay in search of food and strand during El Niño events (TMMC, 2016). Equatorial sea surface temperatures of the Pacific Ocean have been below average across most of the Pacific. La Niña conditions are likely to remain into the spring of 2023, after which conditions are expected to become more neutral. However, it is unlikely El Niño conditions will develop later in 2023 (NOAA, 2022). Northern fur seals were not observed during prior LWMEP monitoring (AECOM, 2019, 2020, 2021) nor during the POWRP monitoring (AECOM, 2022). While it is unlikely that northern fur seals would occur in the project areas during in-water activities, Chevron conservatively estimated that a maximum of 10 northern fur seals could occur enter the project area.

Take Estimation

Here, we describe how the information provided above is synthesized to produce a quantitative estimate of the take that is reasonably likely to occur.

Take estimate calculations vary by species. To calculate take by Level B harassment for harbor seals, California sea lions, and harbor porpoises, NMFS

multiplied the daily occurrence estimates described in the *Marine Mammal Occurrence* section by the number of project days (Table 7).

For bottlenose dolphins, Chevron estimated, and NMFS concurs, that one group of eight bottlenose dolphins may be taken by Level B harassment every month of the project. Therefore, Chevron requested, and NMFS has authorized, 32 takes of bottlenose dolphins by Level B harassment.

Chevron based requested take by Level B harassment for gray whales upon total daily occurrence estimates during the project period. Chevron conservatively estimated, and NMFS concurs, that two gray whales may enter the project area per year. Therefore, Chevron requested, and NMFS has authorized, two takes of gray whales by Level B harassment (Table 7).

For northern elephant seals, Chevron conservatively estimated, and NMFS concurs, that one northern elephant seal could enter the project area once every 3 days during in-water construction activities. Therefore, Chevron requested, and NMFS has authorized, 10 takes of northern elephant seals by Level B harassment (Table 7).

Based upon prior occurrences in the Bay, Chevron conservatively estimated, and NMFS concurs, that a maximum of 10 northern fur seals could occur in the project area during the in-water construction activity period. Therefore, Chevron requested, and NMFS has authorized 10 takes of northern fur seals by Level B harassment (Table 7).

Chevron did not request, nor has NMFS authorized, take by Level A harassment. For all pile driving activities, Chevron will to implement shutdown zones (described further in the Mitigation section) that are expected to effectively prevent take by Level A harassment.

TABLE 7—AUTHORIZED TAKE BY LEVEL B HARASSMENT AND ESTIMATED TAKE AS A PERCENTAGE OF THE POPULATION

Species	Expected occurrence	Authorized take by level B harassment			Estimated take as a percentage of population
		Impact install	Vibratory install/extract	Total	
Harbor seal	237 seals per day	4,977	2,133	7,110	23
Sea lion	1 sea lion per day ¹	21	9	30	0.012
Harbor porpoise	1 harbor porpoise per day ¹	21	9	30	0.39
Bottlenose dolphin	Up to 8 dolphins once per month	N/A	N/A	32	1.77
Gray whale	2 whales over project duration	N/A	N/A	2	0.007
Northern elephant seal	1 seal every 3 days	N/A	N/A	10	0.005
Northern fur seal	10 seals over project duration	N/A	N/A	10	0.071

¹ Rounded daily occurrence to one individual per day.

Mitigation

In order to issue an IHA under section 101(a)(5)(D) of the MMPA, NMFS must

set forth the permissible methods of taking pursuant to the activity, and other means of effecting the least

practicable impact on the species or stock and its habitat, paying particular attention to rookeries, mating grounds,

and areas of similar significance, and on the availability of the species or stock for taking for certain subsistence uses (latter not applicable for this action). NMFS regulations require applicants for incidental take authorizations to include information about the availability and feasibility (economic and technological) of equipment, methods, and manner of conducting the activity or other means of effecting the least practicable adverse impact upon the affected species or stocks, and their habitat (50 CFR 216.104(a)(11)).

In evaluating how mitigation may or may not be appropriate to ensure the least practicable adverse impact on species or stocks and their habitat, as well as subsistence uses where applicable, NMFS considers two primary factors:

(1) The manner in which, and the degree to which, the successful implementation of the measure(s) is expected to reduce impacts to marine mammals, marine mammal species or stocks, and their habitat. This considers the nature of the potential adverse impact being mitigated (likelihood, scope, range). It further considers the likelihood that the measure would be effective if implemented (probability of accomplishing the mitigating result if implemented as planned), the likelihood of effective implementation (probability implemented as planned), and;

(2) The practicability of the measures for applicant implementation, which may consider such things as cost, and impact on operations.

Chevron must follow mitigation measures as specified below.

Chevron must ensure that construction supervisors and crews, the monitoring team, and relevant Chevron staff are trained prior to the start of all pile driving activities, so that responsibilities, communication procedures, monitoring protocols, and operational procedures are clearly understood. New personnel joining during the project must be trained prior to commencing work.

Shutdown Zones

Chevron must establish shutdown zones for all pile driving activities. The purpose of a shutdown zone is generally to define an area within which shutdown of the activity will occur upon sighting of a marine mammal (or in anticipation of an animal entering the defined area). Shutdown zones will be based upon the Level A harassment zone for each pile size/type and driving method where applicable, as shown in Table 6. A minimum shutdown zone of 10 m will be required for all in-water construction activities to avoid physical interaction with marine mammals. For pile driving, the radii of the shutdown zones are rounded to the next largest 10 m interval in comparison to the Level A harassment zone for each activity type. If a marine mammal is observed entering or within a shutdown zone during pile driving activity, the activity must be stopped until there is visual confirmation that the animal has left the zone or the animal is not sighted for a period of 15 minutes. Shutdown zones

for each activity type are shown in Table 8.

All marine mammals will be monitored in the Level B harassment zones and throughout the area as far as visual monitoring can take place. If a marine mammal enters the Level B harassment zone, in-water activities will continue and PSOs will document the animal's presence within the estimated harassment zone.

Chevron will also establish shutdown zones for all marine mammals for which take has not been authorized or for which incidental take has been authorized but the authorized number of takes has been met. These zones will be equivalent to the Level B harassment zones for each activity. If a marine mammal species for which take is not authorized or a species for which incidental take has been authorized but the authorized number of takes has been met enters the shutdown zone, all in-water activities must cease until the animal leaves the zone or has not been observed for at least 1 hour, and NMFS will be notified about species and precautions taken. Pile removal will proceed if the animal is observed to leave the Level B harassment zone or if 1 hour has passed since the last observation.

If shutdown and/or clearance procedures will result in an imminent safety concern, as determined by Chevron or its designated officials, the in-water activity will be allowed to continue until the safety concern has been addressed, and the animal will be continuously monitored.

TABLE 8—SHUTDOWN ZONES BY ACTIVITY TYPE

Method	Pile type	Shutdown zones (m) ¹				
		LF	MF	HF	PW	OW
Pile removal activities:						
Vibratory extract	36-inch steel pile	20	10	30	20	10
	18-inch concrete pile	10	10	10	10	10
Pile installation activities:						
Impact install	24-inch square concrete pile.	40	10	40	20	10
Vibratory install	36-inch steel pile	20	10	30	20	10

¹ Observers will monitor as far as the eye can see.

Protected Species Observers

The placement of PSOs during all pile driving activities (described in the Monitoring and Reporting section) will ensure that the entire shutdown zone is visible. Should environmental conditions deteriorate such that the entire shutdown zone will not be visible (e.g., fog, heavy rain), pile driving will be delayed until the PSO is confident

marine mammals within the shutdown zone could be detected.

PSOs will monitor the full shutdown zones and the Level B harassment zones to the extent practicable. Monitoring zones provide utility for observing by establishing monitoring protocols for areas adjacent to the shutdown zones. Monitoring zones enable observers to be aware of and communicate the presence

of marine mammals in the project areas outside the shutdown zones and thus prepare for a potential cessation of activity should the animal enter the shutdown zone.

Pre-and Post-Activity Monitoring

Monitoring must take place from 30 minutes prior to initiation of pile driving activities (i.e., pre-clearance monitoring) through 30 minutes post-

completion of pile driving. Prior to the start of daily in-water construction activity, or whenever a break in pile driving of 30 minutes or longer occurs, PSOs will observe the shutdown and monitoring zones for a period of 30 minutes. The shutdown zone will be considered cleared when a marine mammal has not been observed within the zone for a 30-minute period. If a marine mammal is observed within the shutdown zones listed in Table 10, pile driving activity will be delayed or halted. If work ceases for more than 30 minutes, the pre-activity monitoring of the shutdown zones will commence. A determination that the shutdown zone is clear must be made during a period of good visibility (*i.e.*, the entire shutdown zone and surrounding waters must be visible to the naked eye).

Soft-Start Procedures

Soft-start procedures provide additional protection to marine mammals by providing warning and/or giving marine mammals a chance to leave the area prior to the hammer operating at full capacity. For impact pile driving, contractors will be required to provide an initial set of three strikes from the hammer at reduced energy, followed by a 30-second waiting period, then two subsequent reduced-energy strike sets. Soft-start will be implemented at the start of each day's impact pile driving and at any time following cessation of impact pile driving for a period of 30 minutes or longer.

Bubble Curtain

A bubble curtain must be employed during all impact pile installation of the 24-inch square concrete piles to interrupt the acoustic pressure and reduce impact on marine mammals. The bubble curtain must distribute air bubbles around 100 percent of the piling circumference for the full depth of the water column. The lowest bubble ring must be in contact with the mudline for the full circumference of the ring. The weights attached to the bottom ring must ensure 100 percent substrate contact. No parts of the ring or other objects may prevent full substrate contact. Air flow to the bubblers must be balanced around the circumference of the pile.

Based on our evaluation of the applicant's planned measures, NMFS has determined that the mitigation measures provide the means of effecting the least practicable impact on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance.

Monitoring and Reporting

In order to issue an IHA for an activity, section 101(a)(5)(D) of the MMPA states that NMFS must set forth requirements pertaining to the monitoring and reporting of such taking. The MMPA implementing regulations at 50 CFR 216.104(a)(13) indicate that requests for authorizations must include the suggested means of accomplishing the necessary monitoring and reporting that would result in increased knowledge of the species and of the level of taking or impacts on populations of marine mammals that are expected to be present while conducting the activities. Effective reporting is critical both to compliance as well as ensuring that the most value is obtained from the required monitoring.

Monitoring and reporting requirements prescribed by NMFS should contribute to improved understanding of one or more of the following:

- Occurrence of marine mammal species or stocks in the area in which take is anticipated (*e.g.*, presence, abundance, distribution, density);
- Nature, scope, or context of likely marine mammal exposure to potential stressors/impacts (individual or cumulative, acute or chronic), through better understanding of: (1) action or environment (*e.g.*, source characterization, propagation, ambient noise); (2) affected species (*e.g.*, life history, dive patterns); (3) co-occurrence of marine mammal species with the activity; or (4) biological or behavioral context of exposure (*e.g.*, age, calving or feeding areas);
- Individual marine mammal responses (behavioral or physiological) to acoustic stressors (acute, chronic, or cumulative), other stressors, or cumulative impacts from multiple stressors;
- How anticipated responses to stressors impact either: (1) long-term fitness and survival of individual marine mammals; or (2) populations, species, or stocks;
- Effects on marine mammal habitat (*e.g.*, marine mammal prey species, acoustic habitat, or other important physical components of marine mammal habitat); and,
- Mitigation and monitoring effectiveness.

Visual Monitoring

Marine mammal monitoring must be conducted in accordance with the conditions in this section, the Monitoring Plan, and this IHA. Marine mammal monitoring during pile driving activities will be conducted by PSO's

meeting NMFS' standards and in a manner consistent with the following:

- PSOs must be independent of the activity contractor (for example, employed by a subcontractor) and have no other assigned tasks during monitoring periods;
- At least one PSO will have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization;
- Other PSOs may substitute other relevant experience, education (degree in biological science or related field), or training for prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization;
- Where a team of three or more PSOs is required, a lead observer or monitoring coordinator must be designated. The lead observer must have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization; and
- PSOs must be approved by NMFS prior to beginning any activity subject to the IHA.

PSOs should have the following additional qualifications:

- Ability to conduct field observations and collect data according to assigned protocols;
- Experience or training in the field identification of marine mammals, including the identification of behaviors;
- Sufficient training, orientation, or experience with the construction operation to provide for personal safety during observations;
- Writing skills sufficient to prepare a report of observations including but not limited to the number and species of marine mammals observed; dates and times when in-water construction activities were conducted; dates, times, and reason for implementation of mitigation (or why mitigation was not implemented when required); and marine mammal behavior; and
- Ability to communicate orally, by radio or in person, with project personnel to provide real-time information on marine mammals observed in the area as necessary.

Chevron will have at least two PSOs stationed at the best possible vantage points in the project area to monitor during all pile driving activities. Monitoring will occur from elevated locations along the shoreline or on barges where the entire shutdown zones and monitoring zones are visible. PSOs will be equipped with high quality binoculars for monitoring and radios or cell phones for maintaining contact

with work crews. Monitoring will be conducted 30 minutes before, during, and 30 minutes after all in water construction activities. In addition, PSOs will record all incidents of marine mammal occurrence, regardless of distance from activity, and will document any behavioral reactions in concert with distance from piles being driven or removed. Pile driving activities include the time to install or remove a single pile or series of piles, as long as the time elapsed between uses of the pile driving equipment is no more than 30 minutes.

In addition to monitoring on days that construction will occur, as planned by the applicant, Chevron will conduct biological monitoring within 1 week ahead of the project's start date to establish baseline observation. These observation periods will encompass different tide levels at different hours of the day.

Data Collection

Chevron will record detailed information about implementation of shutdowns, counts and behaviors (if possible) of all marine mammal species observed, times of observations, construction activities that occurred, any acoustic and visual disturbances, and weather conditions. PSOs will use approved data forms to record the following information:

- Date and time that permitted construction activity begins and ends;
- Type of pile removal activities that take place;
- Weather parameters (*e.g.*, percent cloud cover, percent glare, visibility, air temperature, tide level, Beaufort sea state);
- Species counts, and, if possible, sex and age classes of any observed marine mammal species;
- Marine mammal behavior patterns, including bearing and direction of travel;
- Any observed behavioral reactions just prior to, during, or after construction activities;
- Location of marine mammal, distance from observer to the marine mammal, and distance from pile driving activities to marine mammals;
- Whether an observation required the implementation of mitigation measures, including shutdown procedures and the duration of each shutdown; and
- Any acoustic or visual disturbances that take place.

Reporting

Chevron must submit a draft marine mammal monitoring report to NMFS within 90 days after the completion of

pile driving activities, or 60 days prior to the requested issuance of any future IHAs for the project, or other projects at the same location, whichever comes first. A final report must be prepared and submitted within 30 calendar days following receipt of any NMFS comments on the draft report. If no comments are received from NMFS within 30 calendar days of receipt of the draft report, the report shall be considered final. The marine mammal report will include an overall description of work completed, a narrative regarding marine mammal sightings, and associated PSO data sheets and/or raw sighting data. Specifically, the report will include:

- Dates and times (begin and end) of all marine mammal monitoring;
- Construction activities occurring during each daily observation period, including: (a) How many and what type of piles were driven or removed and the method (*i.e.*, impact or vibratory); and (b) the total duration of time for each pile (vibratory driving) number of strikes for each pile (impact driving);
- PSO locations during marine mammal monitoring; and
- Environmental conditions during monitoring periods (at beginning and end of PSO shift and whenever conditions change significantly), including Beaufort sea state and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon, and estimated observable distance.

For each observation of a marine mammal, the following will be recorded:

- Name of PSO who sighted the animal(s) and PSO location and activity at time of sighting;
- Time of sighting;
- Identification of the animal(s) (*e.g.*, genus/species, lowest possible taxonomic level, or unidentified), PSO confidence in identification, and the composition of the group if there is a mix of species;
- Distance and location of each observed marine mammal relative to pile being driven or removed for each sighting;
- Estimated number of animals (min/max/best estimate);
- Estimated number of animals by cohort (adults, juveniles, neonates, group composition, *etc.*);
- Description of any marine mammal behavioral observations (*e.g.*, observed behaviors such as feeding or traveling), including an assessment of behavioral responses thought to have resulted from the activity (*e.g.*, no response or changes in behavioral state such as ceasing

feeding, changing direction, flushing, or breaching); and

- Animal's closest point of approach and estimated time spent within the harassment zone.

Additionally, Chevron must include the following information in the report:

- Number of marine mammals detected within the harassment zones, by species; and
- Detailed information about any implementation of any mitigation triggered (*e.g.*, shutdowns and delays), a description of specific actions that ensured, and resulting changes in behavior of the animal(s), if any.

In the event that personnel involved in the construction activities discover an injured or dead marine mammal, Chevron will report the incident to the Office of Protected Resources (OPR) (*PR.ITP.MonitoringReports@noaa.gov*), NMFS and to the West Coast regional stranding network (866-767-6114) as soon as feasible. If the death or injury was clearly caused by the specified activity, Chevron will immediately cease the specified activities until NMFS is able to review the circumstances of the incident and determine what, if any, additional measures are appropriate to ensure compliance with the terms of the IHAs. Chevron must not resume their activities until notified by NMFS.

The report will include the following information:

- Time, date, and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
- Species identification (if known) or description of the animal(s) involved;
- Condition of the animal(s) (including carcass condition if the animal is dead);
- Observed behaviors of the animal(s), if alive;
- If available, photographs or video footage of the animal(s); and
- General circumstances under which the animal was discovered.

Negligible Impact Analysis and Determination

NMFS has defined negligible impact as an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival (50 CFR 216.103). A negligible impact finding is based on the lack of likely adverse effects on annual rates of recruitment or survival (*i.e.*, population-level effects). An estimate of the number of takes alone is not enough information on which to base an impact

determination. In addition to considering estimates of the number of marine mammals that might be “taken” through harassment, NMFS considers other factors, such as the likely nature of any impacts or responses (e.g., intensity, duration), the context of any impacts or responses (e.g., critical reproductive time or location, foraging impacts affecting energetics), as well as effects on habitat, and the likely effectiveness of the mitigation. We also assess the number, intensity, and context of estimated takes by evaluating this information relative to population status. Consistent with the 1989 preamble for NMFS’ implementing regulations (54 FR 40338, September 29, 1989), the impacts from other past and ongoing anthropogenic activities are incorporated into this analysis via their impacts on the baseline (e.g., as reflected in the regulatory status of the species, population size and growth rate where known, ongoing sources of human-caused mortality, or ambient noise levels).

To avoid repetition, the discussion of our analysis applies to all the species listed in Table 2, given that the anticipated effects of this activity on these different marine mammal stocks are expected to be similar. There is little information about the nature or severity of the impacts, or the size, status, or structure of any of these species or stocks that would lead to a different analysis for this activity.

Level A harassment is extremely unlikely given the small size of the Level A harassment isopleths and the required mitigation measures designed to minimize the possibility of injury to marine mammals. No serious injury or mortality is anticipated given the nature of the activity.

Pile driving activities have the potential to disturb or displace marine mammals. Specifically, the project activities may result in take, in the form of Level B harassment from underwater sounds generated from impact and vibratory pile driving activities. Potential takes could occur if individuals move into the ensonified zones when these activities are underway.

The takes by Level B harassment will be due to potential behavioral disturbance. The potential for harassment is minimized through construction methods and the implementation of planned mitigation strategies (see Mitigation section).

Take will occur within a limited, confined area of each stock’s range. Further, the amount of take authorized is extremely small when compared to stock abundance.

No marine mammal stocks for which take is authorized are listed as threatened or endangered under the ESA or determined to be strategic or depleted under the MMPA. The relatively low marine mammal occurrences in the area, small shutdown zones, and planned monitoring make injury takes of marine mammals unlikely. The shutdown zones will be thoroughly monitored before the pile driving activities begin, and activities will be postponed if a marine mammal is sighted within the shutdown zone. There is a high likelihood that marine mammals will be detected by trained observers under environmental conditions described for the project. Limiting construction activities to daylight hours will also increase detectability of marine mammals in the area. Therefore, the mitigation and monitoring measures are expected to eliminate the potential for injury and Level A harassment as well as reduce the amount and intensity of Level B behavioral harassment. Furthermore, the pile driving activities analyzed here are similar to, or less impactful than, numerous construction activities conducted in other similar locations which have occurred with no reported injuries or mortality to marine mammals, and no known long-term adverse consequences from behavioral harassment.

Anticipated and authorized takes are expected to be limited to short-term Level B harassment (behavioral disturbance) as construction activities will occur intermittently over the course of 30 days. Effects on individuals taken by Level B harassment, based upon reports in the literature as well as monitoring from other similar activities, may include increased swimming speeds, increased surfacing time, increased haul out time by pinnipeds, or decreased foraging (e.g., Thorson and Reyff, 2006; NAVFAC SW, 2018b). Individual animals, even if taken multiple times, will likely move away from the sound source and be temporarily displaced from the area due to elevated noise level during pile removal. Marine mammals could also experience TTS if they move into the Level B harassment zone. TTS is a temporary loss of hearing sensitivity when exposed to loud sound, and the hearing threshold is expected to recover completely within minutes to hours. Thus, it is not considered an injury. While TTS could occur, it is not considered a likely outcome of this activity. Repeated exposures of individuals to levels of sounds that could cause Level B harassment are

unlikely to considerably significantly disrupt foraging behavior or result in significant decrease in fitness, reproduction, or survival for the affected individuals. In all, there will be no adverse impacts to the stock as a whole.

As previously described, an Unusual Mortality Event (UME) has been declared for Eastern Pacific gray whales. However, we do not expect authorized takes in this action to exacerbate the ongoing UME. As mentioned previously, no injury or mortality is authorized, and take by Level B harassment is limited (two takes over the duration of the project). Therefore, we do not expect the take authorization to compound the ongoing UME.

The project is not expected to have significant adverse effects on marine mammal habitat. There are no known Biologically Important Areas (BIAs) or ESA-designated critical habitat within the project area, and the activities will not permanently modify existing marine mammal habitat. Although harbor seal haulout sites are located in the Bay, hauled out seals are not likely to be impacted. PSOs during the seismic retrofit of the Richmond Bridge did not note any decline in use by harbor seals at Castro Rocks, a haulout site which is approximately 20 to 100 m from the bridge (Greene *et al.*, 2006) and 560 m from the project area. In addition, any pupping that may occur at Castro Rocks will take place outside of the work window for the pile driving activities. The activities may cause fish to leave the area temporarily. This could impact marine mammals’ foraging opportunities in a limited portion of the foraging range, however, due to the short duration of activities and the relatively small area of affected habitat, the impacts to marine mammal habitat are not expected to cause significant or long-term negative consequences.

In combination, these factors, as well as the available body of evidence from other similar activities, demonstrate that the potential effects of the specified activities will have only minor, short-term effects on individuals. The specified activities are not expected to impact reproduction or survival of any individual marine mammals, much less have impacts on annual rates of recruitment or survival.

In summary and as described above, the following factors primarily support our determination that the impacts resulting from this activity are not expected to adversely affect any of the species or stocks through effects on annual rates of recruitment or survival:

- No serious injury, mortality, or Level A harassment is anticipated or authorized;

- The specified activities and associated ensoufied areas are very small relative to the overall habitat ranges of all species;
- The project area does not overlap known BIAs or ESA-designated critical habitat;
- The lack of anticipated significant or long-term effects to marine mammal habitat;
- The presumed efficacy of the mitigation measures in reducing the effects of the specified activity; and
- Monitoring reports from similar work in the Bay have documented little to no effect on individuals of the same species impacted by the specified activities.

Based on the analysis contained herein of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the monitoring and mitigation measures, NMFS finds that the total marine mammal take from the activity will have a negligible impact on all affected marine mammal species or stocks.

Small Numbers

As noted previously, only take of small numbers of marine mammals may be authorized under sections 101(a)(5)(A) and (D) of the MMPA for specified activities other than military readiness activities. The MMPA does not define small numbers and so, in practice, where estimated numbers are available, NMFS compares the number of individuals taken to the most appropriate estimation of abundance of the relevant species or stock in our determination of whether an authorization is limited to small numbers of marine mammals. When the predicted number of individuals to be taken is fewer than one-third of the species or stock abundance, the take is considered to be of small numbers. Additionally, other qualitative factors may be considered in the analysis, such as the temporal or spatial scale of the activities.

The amount of take NMFS has authorized is below one-third of the estimated stock abundances for all seven stocks (refer back to Table 8). For most stocks, the authorized take of individuals is less than 2 percent of the abundance of the affected stock (with exception of harbor seals at 23 percent). This is likely a conservative estimate because it assumes all takes are of different individual animals, which is likely not the case for harbor seals, given the nearby haulout. Some individuals may return multiple times in a day, but PSOs will count them as

separate takes if they cannot be individually identified.

Based on the analysis contained herein of the activity (including the mitigation and monitoring measures) and the anticipated take of marine mammals, NMFS finds that small numbers of marine mammals will be taken relative to the population size of the affected species or stocks.

Unmitigable Adverse Impact Analysis and Determination

There are no relevant subsistence uses of the affected marine mammal stocks or species implicated by this action. Therefore, NMFS has determined that the total taking of affected species or stocks would not have an unmitigable adverse impact on the availability of such species or stocks for taking for subsistence purposes.

Endangered Species Act

Section 7(a)(2) of the Endangered Species Act of 1973 (ESA; 16 U.S.C. 1531 *et seq.*) requires that each Federal agency insure that any action it authorizes, funds, or carries out 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. To ensure ESA compliance for the issuance of IHAs, NMFS consults internally whenever we propose to authorize take for endangered or threatened species.

No incidental take of ESA-listed species is authorized or expected to result from this activity. Therefore, NMFS has determined that formal consultation under section 7 of the ESA is not required for this action.

National Environmental Policy Act

To comply with the National Environmental Policy Act of 1969 (NEPA; 42 U.S.C. 4321 *et seq.*) and NOAA Administrative Order (NAO) 216-6A, NMFS must review our proposed action (*i.e.*, the issuance of an IHA) with respect to potential impacts on the human environment.

This action is consistent with categories of activities identified in Categorical Exclusion B4 (IHAs with no anticipated serious injury or mortality) of the Companion Manual for NOAA Administrative Order 216-6A, which do not individually or cumulatively have the potential for significant impacts on the quality of the human environment and for which we have not identified any extraordinary circumstances that would preclude this categorical exclusion. Accordingly, NMFS has determined that the issuance of the IHA

qualifies to be categorically excluded from further NEPA review.

Authorization

NMFS has issued an IHA to Chevron for the potential harassment of small numbers of seven marine mammal species incidental to the LWMEP in San Francisco Bay, California, provided the previously mentioned mitigation, monitoring, and reporting requirements are followed.

Dated: May 15, 2023.

Shannon Bettridge,

Chief, Marine Mammal and Sea Turtle Conservation Division, Office of Protected Resources, National Marine Fisheries Service.

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648-XD010]

Taking and Importing Marine Mammals; Taking Marine Mammals Incidental to Geophysical Surveys Related to Oil and Gas Activities in the Gulf of Mexico

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of issuance of Letter of Authorization.

SUMMARY: In accordance with the Marine Mammal Protection Act (MMPA), as amended, its implementing regulations, and NMFS' MMPA Regulations for Taking Marine Mammals Incidental to Geophysical Surveys Related to Oil and Gas Activities in the Gulf of Mexico, notification is hereby given that a Letter of Authorization (LOA) has been issued to LLOG Exploration Company (LLOG) for the take of marine mammals incidental to geophysical survey activity in the Gulf of Mexico.

DATES: The LOA is effective from the date of issuance through December 31, 2024.

ADDRESSES: The LOA, LOA request, and supporting documentation are available online at: www.fisheries.noaa.gov/action/incidental-take-authorization-oil-and-gas-industry-geophysical-survey-activity-gulf-mexico. In case of problems accessing these documents, please call the contact listed below (see **FOR FURTHER INFORMATION CONTACT**).

FOR FURTHER INFORMATION CONTACT:
Jenna Harlacher, Office of Protected
Resources, NMFS, (301) 427-8401.

SUPPLEMENTARY INFORMATION:

Background

Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are issued or, if the taking is limited to harassment, a notice of a proposed authorization is provided to the public for review.

An authorization for incidental takings shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s), will not have an unmitigable adverse impact on the availability of the species or stock(s) for subsistence uses (where relevant), and if the permissible methods of taking and requirements pertaining to the mitigation, monitoring and reporting of such takings are set forth. NMFS has defined “negligible impact” in 50 CFR 216.103 as an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival.

Except with respect to certain activities not pertinent here, the MMPA defines “harassment” as: any act of pursuit, torment, or annoyance which (i) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment); or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment).

On January 19, 2021, we issued a final rule with regulations to govern the unintentional taking of marine mammals incidental to geophysical survey activities conducted by oil and gas industry operators, and those persons authorized to conduct activities on their behalf (collectively “industry operators”), in Federal waters of the U.S. Gulf of Mexico (GOM) over the course of 5 years (86 FR 5322, January 19, 2021). The rule was based on our findings that the total taking from the specified activities over the 5-year period will have a negligible impact on the affected species or stock(s) of marine mammals and will not have an

unmitigable adverse impact on the availability of those species or stocks for subsistence uses. The rule became effective on April 19, 2021.

Our regulations at 50 CFR 217.180 *et seq.* allow for the issuance of LOAs to industry operators for the incidental take of marine mammals during geophysical survey activities and prescribe the permissible methods of taking and other means of effecting the least practicable adverse impact on marine mammal species or stocks and their habitat (often referred to as mitigation), as well as requirements pertaining to the monitoring and reporting of such taking. Under 50 CFR 217.186(e), issuance of an LOA shall be based on a determination that the level of taking will be consistent with the findings made for the total taking allowable under these regulations and a determination that the amount of take authorized under the LOA is of no more than small numbers.

Summary of Request and Analysis

LLOG plans to conduct one of the following vertical seismic profile (VSP) survey types: Zero Offset, Offset, Walkaway VSP, and/or Checkshots within Keathley Canyon Block 829 and Keathley Canyon Block 785. LLOG plans to use either a 12-element, 2,400 cubic inch (in³) airgun array, or a 6-element, 1,500 in³ airgun array. Please see LLOG’s application for additional detail.

Consistent with the preamble to the final rule, the survey effort proposed by LLOG in its LOA request was used to develop LOA-specific take estimates based on the acoustic exposure modeling results described in the preamble (86 FR 5322, January 19, 2021). In order to generate the appropriate take number for authorization, the following information was considered: (1) survey type; (2) location (by modeling zone);¹ (3) number of days; and (4) season.² The acoustic exposure modeling performed in support of the rule provides 24-hour exposure estimates for each species, specific to each modeled survey type in each zone and season.

No VSP surveys were included in the modeled survey types, and use of existing proxies (*i.e.*, 2D, 3D NAZ, 3D WAZ, Coil) is generally conservative for use in evaluation of VSP survey effort. Summary descriptions of these modeled survey geometries are available in the

preamble to the proposed rule (83 FR 29212, June 22, 2018). Coil was selected as the best available proxy survey type because the spatial coverage of the planned survey is most similar to that associated with the coil survey pattern.

For the planned survey, the seismic source array will be deployed in one of the following forms: Zero Offset VSP—deployed from a drilling rig at or near the borehole, with the seismic receivers (*i.e.*, geophones) deployed in the borehole on wireline at specified depth intervals; Offset VSP—in a fixed position deployed from a supply vessel on an offset position; Walkaway VSP—attached to a line, or a series of lines, towed by a supply vessel; 3D VSP—moving along a spiral or line swaths towed by a supply vessel or using a source vessel; or Checkshots—similar to Zero Offset VSP, typically hung from a platform and a sensor placed at a few depths in the well, where only the first energy arrival is recorded. All possible source assemblages except for 3D VSP will be stationary. If 3D VSP is used as the survey design, the area that would be covered would be up to three times the total depth of the well centered around the well head. The coil survey pattern in the model was assumed to cover approximately 144 kilometers squared (km²) per day (compared with approximately 795 km², 199 km², and 845 km² per day for the 2D, 3D NAZ, and 3D WAZ survey patterns, respectively). Among the different parameters of the modeled survey patterns (*e.g.*, area covered, line spacing, number of sources, shot interval, total simulated pulses), NMFS considers area covered per day to be most influential on daily modeled exposures exceeding Level B harassment criteria. Because LLOG’s planned survey is expected to cover either no additional area as a stationary source, or at most up to three times the total depth of the well centered around the well head, the coil proxy is most representative of the effort planned by LLOG in terms of predicted Level B harassment.

In addition, all available acoustic exposure modeling results assume use of a 72 element, 8,000 in³ array. Thus, estimated take numbers for this LOA are considered conservative due to the differences in both the airgun array (12 or 6 elements; 2,400 or 1,500 in³), and in daily survey area planned by LLOG (as mentioned above), as compared to those modeled for the rule.

The survey is planned to occur for up to 5 days in Zone 7. The survey could take place in any season. Therefore, the take estimates for each species are based on the season that has the greater value for the species (*i.e.*, winter or summer).

¹ For purposes of acoustic exposure modeling, the GOM was divided into seven zones. Zone 1 is not included in the geographic scope of the rule.

² For purposes of acoustic exposure modeling, seasons include Winter (December–March) and Summer (April–November).

Additionally, for some species, take estimates based solely on the modeling yielded results that are not realistically likely to occur when considered in light of other relevant information available during the rulemaking process regarding marine mammal occurrence in the GOM. The approach used in the acoustic exposure modeling, in which seven modeling zones were defined over the U.S. GOM, necessarily averages fine-scale information about marine mammal distribution over the large area of each modeling zone. This can result in unrealistic projections regarding the likelihood of encountering particularly rare species and/or species not expected to occur outside particular habitats. Thus, although the modeling conducted for the rule is a natural starting point for estimating take, our rule acknowledged that other information could be considered (see, e.g., 86 FR 5322, (January 19, 2021), discussing the need to provide flexibility and make efficient use of previous public and agency review of other information and identifying that additional public review is not necessary unless the model or inputs used differ substantively from those that were previously reviewed by NMFS and the public). For this survey, NMFS has other relevant information reviewed during the rulemaking that indicates use of the acoustic exposure modeling to generate a take estimate for killer whales produces results inconsistent with what is known regarding their occurrence in the GOM. Accordingly, we have adjusted the calculated take estimates for that species as described below.

Killer whales are the most rarely encountered species in the GOM, typically in deep waters of the central GOM (Roberts *et al.*, 2015; Maze-Foley and Mullin, 2006). As discussed in the final rule, the density models produced by Roberts *et al.* (2016) provide the best available scientific information regarding predicted density patterns of cetaceans in the U.S. GOM. The predictions represent the output of models derived from multi-year observations and associated environmental parameters that incorporate corrections for detection bias. However, in the case of killer whales, the model is informed by few data, as indicated by the coefficient of variation associated with the abundance predicted by the model (0.41, the second-highest of any GOM species model; Roberts *et al.*, 2016). The model's authors noted the expected non-uniform distribution of this rarely-encountered species (as discussed above) and expressed that, due to the

limited data available to inform the model, it “should be viewed cautiously” (Roberts *et al.*, 2015).

NOAA surveys in the GOM from 1992–2009 reported only 16 sightings of killer whales, with an additional 3 encounters during more recent survey effort from 2017–18 (Waring *et al.*, 2013; www.boem.gov/gommapps). Two other species were also observed on fewer than 20 occasions during the 1992–2009 NOAA surveys (Fraser's dolphin and false killer whale).³ However, observational data collected by protected species observers (PSOs) on industry geophysical survey vessels from 2002–2015 distinguish the killer whale in terms of rarity. During this period, killer whales were encountered on only 10 occasions, whereas the next most rarely encountered species (Fraser's dolphin) was recorded on 69 occasions (Barkaszi and Kelly, 2019). The false killer whale and pygmy killer whale were the next most rarely encountered species, with 110 records each. The killer whale was the species with the lowest detection frequency during each period over which PSO data were synthesized (2002–2008 and 2009–2015). This information qualitatively informed our rulemaking process, as discussed at 86 FR 5322, 5334 (January 19, 2021), and similarly informs our analysis here.

The rarity of encounter during seismic surveys is not likely to be the product of high bias on the probability of detection. Unlike certain cryptic species with high detection bias, such as *Kogia* spp. or beaked whales, or deep-diving species with high availability bias, such as beaked whales or sperm whales, killer whales are typically available for detection when present and are easily observed. Roberts *et al.* (2015) stated that availability is not a major factor affecting detectability of killer whales from shipboard surveys, as they are not a particularly long-diving species. Baird *et al.* (2005) reported that mean dive durations for 41 fish-eating killer whales for dives greater than or equal to 1 minute in duration was 2.3–2.4 minutes, and Hooker *et al.* (2012) reported that killer whales spent 78 percent of their time at depths between 0–10 m. Similarly, Kvadsheim *et al.* (2012) reported data from a study of four killer whales, noting that the whales performed 20 times as many dives 1–30 m in depth than to deeper waters, with an average depth during those most common dives of approximately 3 m.

³ However, note that these species have been observed over a greater range of water depths in the GOM than have killer whales.

In summary, killer whales are the most rarely encountered species in the GOM and typically occur only in particularly deep water. This survey would take place in deep waters that would overlap with depths in which killer whales typically occur. While this information is reflected through the density model informing the acoustic exposure modeling results, there is relatively high uncertainty associated with the model for this species, and the acoustic exposure modeling applies mean distribution data over areas where the species is in fact less likely to occur. In addition, as noted above in relation to the general take estimation methodology, the assumed proxy source (72-element, 8,000-in³ array) results in a significant overestimate of the actual potential for take to occur. NMFS' determination in reflection of the information discussed above, which informed the final rule, is that use of the generic acoustic exposure modeling results for killer whales will generally result in estimated take numbers that are inconsistent with the assumptions made in the rule regarding expected killer whale take (86 FR 5322, 5403, January 19, 2021). In this case, use of the acoustic exposure modeling produces an estimate of four killer whale exposures. Given the foregoing, it is unlikely that any killer whales would be encountered during this 5-day survey, and accordingly no take of killer whales is authorized through this LOA.

In addition, in this case, use of the exposure modeling produces results that are smaller than average GOM group sizes for multiple species (Maze-Foley and Mullin, 2006). NMFS' typical practice in such a situation is to increase exposure estimates to the assumed average group size for a species in order to ensure that, if the species is encountered, exposures will not exceed the authorized take number. However, other relevant considerations here lead to a determination that increasing the estimated exposures to average group sizes would likely lead to an overestimate of actual potential take. In this circumstance, the very short survey duration (maximum of 5 days) and relatively small Level B harassment isopleths produced through use of the (at worst) 12-element, 2,400-in³ airgun array (compared with the modeled 72-element, 8,000 in³ array) mean that it is unlikely that certain species would be encountered at all, much less that the encounter would result in exposure of a greater number of individuals than is estimated through use of the exposure modeling results. As a result, in this case NMFS has not increased the

estimated exposure values to assumed average group sizes in authorizing take.

Based on the results of our analysis, NMFS has determined that the level of taking expected for this survey and authorized through the LOA is consistent with the findings made for the total taking allowable under the regulations for the affected species or stocks of marine mammals. See Table 1 in this notice and Table 9 of the rule (86 FR 5322, January 19, 2021).

Small Numbers Determination

Under the GOM rule, NMFS may not authorize incidental take of marine mammals in an LOA if it will exceed “small numbers.” In short, when an acceptable estimate of the individual marine mammals taken is available, if the estimated number of individual

animals taken is up to, but not greater than, one-third of the best available abundance estimate, NMFS will determine that the numbers of marine mammals taken of a species or stock are small. For more information please see NMFS’ discussion of the MMPA’s small numbers requirement provided in the final rule (86 FR 5322, 5438, January 19, 2021).

The take numbers for authorization, which are determined as described above, are used by NMFS in making the necessary small numbers determinations through comparison with the best available abundance estimates (see discussion at 86 FR 5322, 5391, January 19, 2021). For this comparison, NMFS’ approach is to use the maximum theoretical population,

determined through review of current stock assessment reports (SAR; www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments) and model-predicted abundance information (<https://seamap.env.duke.edu/models/Duke/GOM/>). For the latter, for taxa where a density surface model could be produced, we use the maximum mean seasonal (*i.e.*, 3-month) abundance prediction for purposes of comparison as a precautionary smoothing of month-to-month fluctuations and in consideration of a corresponding lack of data in the literature regarding seasonal distribution of marine mammals in the GOM. Information supporting the small numbers determinations is provided in Table 1.

TABLE 1—TAKE ANALYSIS

Species	Authorized take ¹	Abundance ²	Percent abundance
Rice’s whale	0	51	n/a
Sperm whale	26	2,207	1.2
<i>Kogia</i> spp	³ 15	4,373	0.3
Beaked whales	234	3,768	6.2
Rough-toothed dolphin	43	4,853	0.9
Bottlenose dolphin	⁴ 1	176,108	0
Clymene dolphin	115	11,895	1
Atlantic spotted dolphin	0	74,785	n/a
Pantropical spotted dolphin	1,139	102,361	1.1
Spinner dolphin	⁴ 27	25,114	0.1
Striped dolphin	60	5,229	1.1
Fraser’s dolphin	⁴ 19	1,665	1.1
Risso’s dolphin	18	3,764	0.5
Melon-headed whale	⁴ 74	7,003	1.1
Pygmy killer whale	36	2,126	1.7
False killer whale	41	3,204	1.3
Killer whale	0	267	n/a
Short-finned pilot whale	⁴ 6	1,981	0.3

¹ Scalar ratios were not applied in this case due to brief survey duration.

² Best abundance estimate. For most taxa, the best abundance estimate for purposes of comparison with take estimates is considered here to be the model-predicted abundance (Roberts *et al.*, 2016). For those taxa where a density surface model predicting abundance by month was produced, the maximum mean seasonal abundance was used. For those taxa where abundance is not predicted by month, only mean annual abundance is available. For Rice’s whale and killer whale, the larger estimated SAR abundance estimate is used.

³ Includes 1 take by Level A harassment and 14 takes by Level B harassment.

⁴ Modeled exposure estimate less than assumed average group size (Maze-Foley and Mullin, 2006).

Based on the analysis contained herein of LLOG’s proposed survey activity described in its LOA application and the anticipated take of marine mammals, NMFS finds that small numbers of marine mammals will be taken relative to the affected species or stock sizes (*i.e.*, less than one-third of the best available abundance estimate) and therefore the taking is of no more than small numbers.

Authorization

NMFS has determined that the level of taking for this LOA request is consistent with the findings made for the total taking allowable under the incidental take regulations and that the

amount of take authorized under the LOA is of no more than small numbers. Accordingly, we have issued an LOA to LLOG authorizing the take of marine mammals incidental to its geophysical survey activity, as described above.

Dated: May 12, 2023.

Catherine Marzin,

Deputy Director, Office of Protected Resources, National Marine Fisheries Service.

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC871]

Takes of Marine Mammals Incidental to Specified Activities; Taking Marine Mammals Incidental to Marine Site Characterization Surveys in the New York Bight and Central Atlantic

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of an incidental harassment authorization.

SUMMARY: In accordance with the regulations implementing the Marine Mammal Protection Act (MMPA) as amended, notification is hereby given that NMFS has issued an Incidental Harassment Authorization (IHA) to TerraSond Limited (TerraSond) to incidentally harass marine mammals during marine site characterization surveys in the New York Bight (off of New York and New Jersey) and in the Central Atlantic (from Delaware to North Carolina).

DATES: This authorization is effective from April 1, 2024, through March 31, 2025.

FOR FURTHER INFORMATION CONTACT: Ben Laws, Office of Protected Resources, NMFS, (301) 427–8401. Electronic copies of the application and supporting documents, as well as a list of the references cited in this document, may be obtained online at: www.fisheries.noaa.gov/national/marine-mammal-protection/incidental-take-authorizations-other-energy-activities-renewable. In case of problems accessing these documents, please call the contact listed above.

SUPPLEMENTARY INFORMATION:

Background

The MMPA prohibits the “take” of marine mammals, with certain exceptions. Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce (as delegated to NMFS) to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are proposed or, if the taking is limited to harassment, a notice of a proposed IHA is provided to the public for review.

Authorization for incidental takings shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s) and will not have an unmitigable adverse impact on the availability of the species or stock(s) for taking for subsistence uses (where relevant). Further, NMFS must prescribe the permissible methods of taking and other “means of effecting the least practicable adverse impact” on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stocks for taking for certain subsistence uses

(referred to in shorthand as “mitigation”); and requirements pertaining to the mitigation, monitoring and reporting of the takings are set forth. The definitions of all applicable MMPA statutory terms cited above are included in the relevant sections below.

Summary of Request

On May 19, 2022, NMFS received a request from TerraSond for an IHA to take marine mammals incidental to site characterization surveys in the New York Bight. Following NMFS’ review of the application, TerraSond submitted a revised version on July 11, 2022, adding additional planned survey activity in the Central Atlantic. This revised application was deemed adequate and complete. TerraSond’s request is for take of 21 species of marine mammals, by Level B harassment only. Neither TerraSond nor NMFS expect serious injury or mortality to result from this activity and, therefore, an IHA is appropriate. There are no changes from the proposed IHA to the final IHA.

Description of Activity

Overview

TerraSond plans to conduct marine site characterization surveys, including high-resolution geophysical (HRG) surveys, off the coasts of New Jersey and New York (New York Bight) and from Delaware to North Carolina (Central Atlantic). The former portion of survey effort would be conducted on Bureau of Ocean Energy Management (BOEM) Lease Areas OCS–A 0539, 0541, and 0542, while the latter portion of survey effort would be conducted in continental shelf waters of BOEM’s Central Atlantic Call Area. The planned survey effort would be conducted in support of wind energy development.

NMFS notes that, on November 16, 2022, BOEM announced eight draft Wind Energy Areas (WEAs), covering approximately 1.7 million acres (688,000 hectares), in the Central Atlantic for public review and comment. The eight draft WEAs represent a subset of the original 3.9 million acres of the Call Area that the Department of the Interior announced for public comment in April 2022. Therefore, TerraSond’s actual survey effort in the Central Atlantic, which would be dictated by commercial interest, is likely to be less than that described in its application.

The planned marine site characterization survey effort is designed to obtain data sufficient to meet BOEM guidelines for providing geophysical, geotechnical, and geohazard information for site

assessment plan surveys and/or construction and operations plan development. The objective of the surveys is to acquire data on bathymetry, seafloor morphology, subsurface geology, environmental/biological sites, seafloor obstructions, soil conditions, and locations of any man-made, historical or archaeological resources within the respective survey areas. Underwater sound resulting from TerraSond’s potential site characterization survey activities, specifically HRG surveys, has the potential to result in incidental take of marine mammals in the form of Level B behavioral harassment.

Dates and Duration

The potential duration of Central Atlantic HRG survey activity is expected to include a maximum of 1,052 survey days (minimum 661 survey days, depending on final survey plan) over the course of the 1-year period of effectiveness for the IHA, with a “survey day” defined as a 24-hour (hr) activity period in which active acoustic sound sources are used. The potential duration of New York Bight survey activity is expected to include a maximum of 385 survey days. Therefore, the potential total survey days would range from 1,046 to a maximum of 1,437. For both components of the activity, survey activities are anticipated to occur over a minimum of 6–8 months using multiple vessels concurrently and likely throughout most of a year. TerraSond plans to start survey activity as soon as possible, with the IHA effective for a period of 1 year.

Specific Geographic Region

The planned survey activities will occur within the aforementioned BOEM Central Atlantic Call Area and within BOEM’s Lease Areas OCS–A 0539, 0541, and 0542 in the New York Bight. Please see Figures 1 and 2 below or, for color versions, see the same figures in TerraSond’s application. The Central Atlantic survey area comprises approximately 11,500 square kilometers (km²), covering water depths from 20–60 meters (m), and the New York Bight survey area comprises approximately 1,171 km², covering water depths from 30–65 m. As mentioned above, based on BOEM’s contraction of the likely wind energy development area (relative to the initial proposed Call Area), it is likely that actual survey effort in the Central Atlantic may be less than that described in TerraSond’s application.

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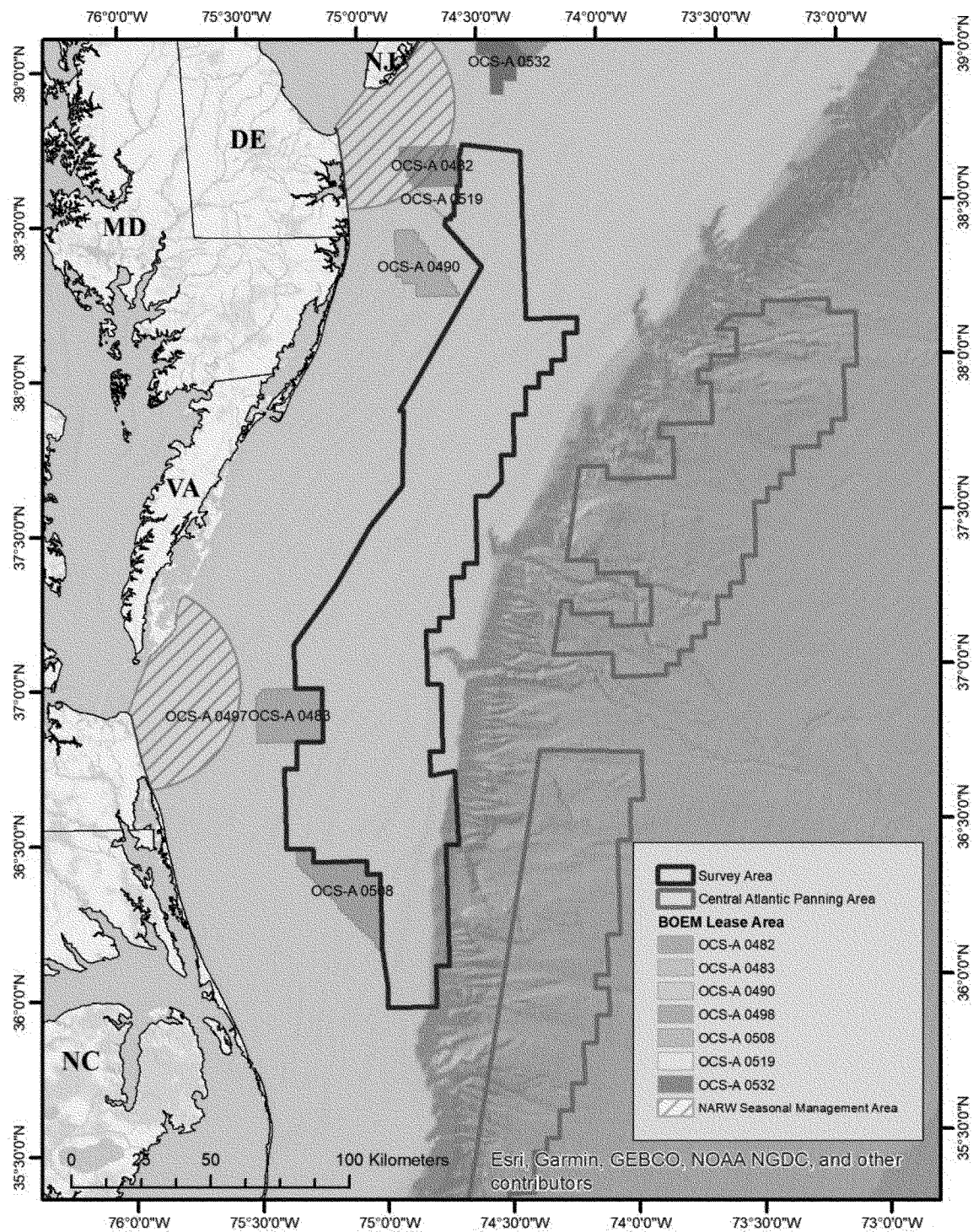


Figure 1 -- Central Atlantic Site Characterization Survey Location

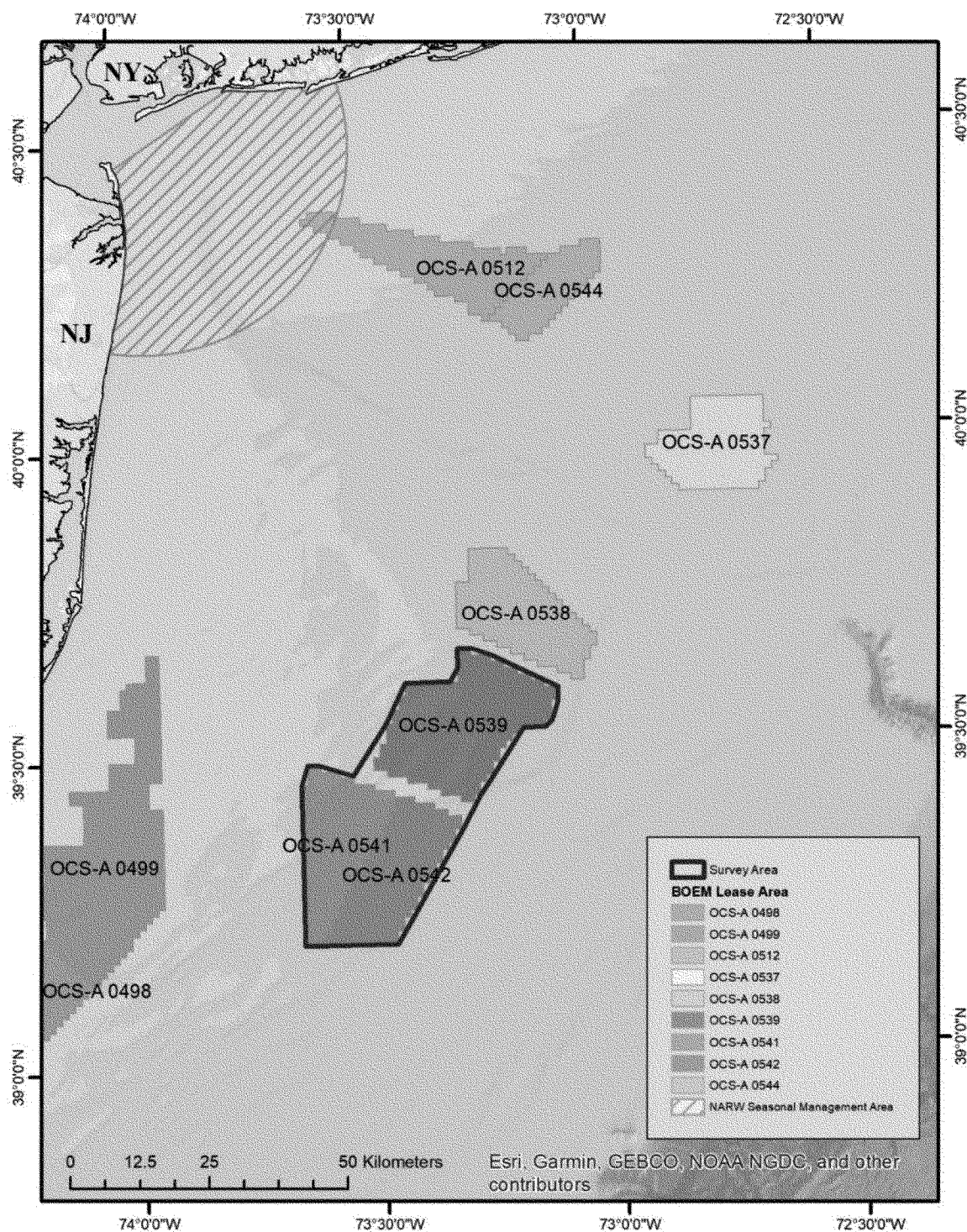


Figure 2 -- New York Bight Site Characterization Survey Location

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Detailed Description of Specific Activity

TerraSond plans to conduct HRG survey operations, including multibeam depth sounding, seafloor imaging, and shallow and medium penetration sub-bottom profiling. The HRG surveys may be conducted using any or all of the

following equipment types: side scan sonar, multibeam echosounder, gradiometers, parametric sub-bottom profiler, or sparkers. TerraSond assumes that HRG survey operations would be conducted 24 hours per day, with an assumed daily survey distance of 100 km. This average distance per day was

calculated by TerraSond from the maximum achievable survey distance assuming 24-hour survey operations and an average vessel speed of 3.5 knots (kn) (6.5 km/hour), and then reducing from there based on prior experience to account for expected downtime related

to weather, equipment malfunction, and other factors.

The only acoustic source planned for use during HRG survey activities planned by TerraSond with expected potential to cause incidental take of marine mammals is the sparker. Sparkers are medium penetration, impulsive sources used to map deeper subsurface stratigraphy, and which may be operated with different numbers of electrode tips to allow tuning of the acoustic waveform for specific applications. Sparkers create omnidirectional acoustic pulses from 50 Hz to 4 kHz, and are typically towed behind the vessel. The sparker system planned for use is the Applied Acoustics Dura-Spark Ultra-High Resolution Seismic (UHRS) 400 + 400 (electrode tips) source, which is essentially two of the same Applied Acoustics Dura-Spark sources stacked on top of each other creating two “decks” to the sparker. However, the decks will not be discharged simultaneously, but will be used in an alternating “flip-flop” pattern (as discussed below). Thus, for all source configurations below, the maximum power expected when discharging the sparker source (single deck) will be 800 joules (J). Crocker and Fratantonio (2016) measured the Applied Acoustics Dura-Spark, but did not provide data for an energy setting near 800 J (for a 400-tip configuration, Crocker and Fratantonio (2016) provide measurements at 500 and 2,000 J). Therefore, TerraSond uses a similar alternative system, which was measured with an input voltage of 750 J, as a surrogate for purposes of analysis. NMFS concurs with this selection, which is described in Table 1.

TABLE 1—SUMMARY OF REPRESENTATIVE HRG EQUIPMENT

Equipment	Operating frequency (kHz)	SL _{rms} (dB re 1 μPa m)	SL _{0-pk} (dB re 1 μPa m)	Pulse duration (width) (millisecond)	Repetition rate (second)	Beamwidth (degrees)
SIG ELC 820 sparker (750 J) ¹	0.3–1.2	203	213	1.1	0.25	Omni

μPa = micropascal; dB = decibel; Omni = omnidirectional source; re = referenced to; PK = zero-to-peak sound pressure level; SL = source level; SPL = root-mean-square sound pressure level.
¹ Proxy for Applied Acoustics Dura-Spark UHRS (800 J).

Central Atlantic—The Central Atlantic activity component includes two different survey phases that may occur involving different survey line spacing and potential survey equipment tow configurations. There are two possible survey methods that may be used during Phase 1, which the applicant refers to as Alternative 1 and Alternative 2. Alternative 1 would involve the use of a single source vessel towing one sparker source composed of two “decks” of 400 electrode tips each stacked on top of each other. The two decks would be discharged in alternating fashion such that only one deck is discharged at a time. Alternative 2 would involve the use of a single source vessel towing 3 of the same sparker sources with a horizontal separation between the sources of 150 m. Alternative 1 describes acquisition along 58,607 km of trackline, while Alternative 2 describes acquisition along 19,536 km of trackline. Only one of these two methods will be used for survey acquisition. Phase 2 will involve a single vessel towing two of the same sparker sources with a horizontal separation between the sources of 30 m, and includes acquisition along 46,573 km of trackline. At an assumed 100 km per day, Phase 1 would require approximately 586 or 195 days, depending on which alternative is ultimately used, and Phase 2 will require approximately 466 days. Therefore, based on the description provided by TerraSond, the Central Atlantic portion of the survey effort is

expected to require either 661 or 1,052 survey days. Up to a total of four source vessels may be active concurrently to accomplish this.

New York Bight—The New York Bight activity component includes three different survey phases that may occur involving different survey line spacing and potential survey equipment tow configurations. Phase 1 involves the use of a single source vessel towing one sparker source composed of two “decks” of 400 electrode tips each stacked on top of each other. As discussed above, the two decks will typically be discharged in alternating fashion such that only one deck is discharged at a time. Phases 2 and 3 involve a single vessel towing two of the same sparker sources with a horizontal separation between the sources of 30 m. These Phases involve acquisition along 14,833, 200, and 23,311 km of trackline, respectively, requiring a total of approximately 385 days. Up to a total of three source vessels may be active concurrently to accomplish this.

Further detail regarding the planned HRG surveys is provided in the **Federal Register** notice for the proposed IHA (87 FR 66658; November 4, 2022). Since that time, no changes have been made to the planned HRG survey activities. Required mitigation, monitoring, and reporting measures are described in detail later in this document (please see Mitigation and Monitoring and Reporting).

Comments and Responses

A notice of NMFS’ proposal to issue an IHA to TerraSond was published in the **Federal Register** on November 4, 2022 (87 FR 66658) for a 30-day comment period. That notice described, in detail, TerraSond’s planned activities, the marine mammal species that may be affected by the activities, and the anticipated effects on marine mammals. In that notice, we requested public input on the request for authorization described therein, our analyses, the proposed authorization, and other aspects of the notice of proposed IHA, and requested that interested persons submit relevant information, suggestions, and comments.

NMFS received two comment letters from private citizens, expressing general opposition to issuance of the IHA or to the underlying associated activities. The comments received suggested that NMFS should not issue the IHA, but without providing information relevant to NMFS’ decision. We reiterate here that NMFS’ proposed action concerns only the authorization of marine mammal take incidental to the planned surveys—NMFS’ authority under the MMPA does not extend to the surveys themselves, or to wind energy development more generally. Further, NMFS does not have discretion regarding issuance of requested incidental take authorizations pursuant to the MMPA, assuming: (1) the total taking associated with a specified activity will have a negligible impact on

the affected species or stock(s); (2) the total taking associated with a specified activity will not have an unmitigable adverse impact on the availability of the species or stock(s) for subsistence uses (not relevant here); (3) the total taking associated with a specified activity is small numbers of marine mammals of any species or stock; and (4) appropriate mitigation, monitoring, and reporting of such takings are set forth, including mitigation measures sufficient to meet the standard of least practicable adverse impact on the affected species or stocks. In addition, one commenter suggested that issuance of the proposed IHA could result in the death of “whales.” We reiterate here that no mortality is anticipated or authorized, and note that the commenter did not provide any specific information supporting this concern.

NMFS also received letters from two non-governmental organizations, Oceana and the Southern Environmental Law Center (SELC), and from the Delaware Department of Natural Resources and Environmental Control (DNREC). SELC's comments were submitted on behalf of an additional nine organizations. All substantive comments, and NMFS' responses, are provided below, and all letters are available online at: <https://www.fisheries.noaa.gov/action/incidental-take-authorization-terrasond-limited-marine-site-characterization-surveys-new>. Please review the letters for full details regarding the comments and underlying justification.

Comment: Oceana raised objections to NMFS' proposed renewal process for potential extension of the 1-year IHA with an abbreviated 15-day public comment period. Oceana recommended that an additional 30-day public comment period is necessary for any IHA renewal request.

Response: NMFS' IHA renewal process meets all statutory requirements. In prior responses to comments about IHA renewals (e.g., 84 FR 52464, October 2, 2019 and 85 FR 53342, August 28, 2020), NMFS explained the IHA renewal process is consistent with the statutory requirements contained in section 101(a)(5)(D) of the MMPA, and further, promotes NMFS' goals of improving conservation of marine mammals and increasing efficiency in the MMPA compliance process. Therefore, we intend continue to implement the existing renewal process.

All IHAs issued, whether an initial IHA or a renewal, are valid for a period of not more than one year. And the public has 30 days to comment on proposed IHAs, with a cumulative total

of 45 days for IHA renewals. The notice of the proposed IHA published in the **Federal Register** on November 4, 2022 (87 FR 66658) provided a 30-day public comment period and made clear that NMFS was seeking comment on the proposed IHA and the potential issuance of a renewal for this survey. As detailed in the **Federal Register** notice for the proposed IHA and on the agency's website, eligibility for renewal is determined on a case-by-case basis, renewals are subject to an additional 15-day public comment period, and the renewal is limited to up to another year of identical or nearly identical activities as described in the Description of Proposed Activities section of the proposed IHA notice or the activities described in the Description of Proposed Activities section of the proposed IHA notice would not be completed by the time the IHA expires and a renewal would allow for completion of the activities beyond that described in the *Dates and Duration* section of this notice. NMFS' analysis of the anticipated impacts on marine mammals caused by the applicant's activities covers both the initial IHA period and the possibility of a 1-year renewal. Therefore, a member of the public considering commenting on a proposed initial IHA also knows exactly what activities (or subset of activities) would be included in a proposed renewal IHA, the potential impacts of those activities, the maximum amount and type of take that could be caused by those activities, the mitigation and monitoring measures that would be required, and the basis for the agency's negligible impact determinations, least practicable adverse impact findings, small numbers findings, and (if applicable) the no unmitigable adverse impact on subsistence use finding—all the information needed to provide complete and meaningful comments on a possible renewal at the time of considering the proposed initial IHA. Reviewers have the information needed to meaningfully comment on both the immediate proposed IHA and a possible 1-year renewal, should the IHA holder choose to request one.

While there would be additional documents submitted with a renewal request, for a qualifying renewal these would be limited to documentation that NMFS would make available and use to verify that the activities are identical to those in the initial IHA, are nearly identical such that the changes would have either no effect on impacts to marine mammals or decrease those impacts, or are a subset of activities already analyzed and authorized but not

completed under the initial IHA. NMFS would also need to confirm, among other things, that the activities would occur in the same location; involve the same species and stocks; provide for continuation of the same mitigation, monitoring, and reporting requirements; and that no new information has been received that would alter the prior analysis. The renewal request would also contain a preliminary monitoring report, in order to verify that effects from the activities do not indicate impacts of a scale or nature not previously analyzed. The additional 15-day public comment period, which includes NMFS' direct notice to anyone who commented on the proposed initial IHA, provides the public an opportunity to review these few documents, provide any additional pertinent information, and comment on whether they think the criteria for a renewal have been met. Combined together, the 30-day public comment period on the initial IHA and the additional 15-day public comment period on the renewal of the same or nearly identical activities, provides the public with a total of 45 days to comment on the potential for renewal of the IHA.

In addition to the IHA renewal process being consistent with all requirements under section 101(a)(5)(D), it is also consistent with Congress' intent for issuance of IHAs to the extent reflected in statements in the legislative history of the MMPA. Through the description of the process and express invitation to comment on specific potential renewals in the Request for Public Comments section of each proposed IHA, the description of the process on NMFS' website, further elaboration on the process through responses to comments such as these, posting of substantive documents on the agency's website, and provision of 30 or 45 days for public review and comment on all proposed initial IHAs and renewals respectively, NMFS has ensured that the public is “invited and encouraged to participate fully in the agency's decision-making process,” as Congress intended.

Comment: Oceana stated that NMFS must utilize the best available scientific evidence, and suggested that NMFS has not done so, specifically referencing information regarding the North Atlantic right whale (NARW) such as updated population estimates, habitat usage in the survey area, and seasonality information. Oceana specifically asserted that NMFS is not using the best available scientific evidence with regards to the NARW population estimate.

Response: NMFS agrees the best available scientific evidence should be used for assessing NARW abundance estimates. Following the recent publication of NMFS' draft 2022 Stock Assessment Reports (SAR), NMFS updated the information relied upon herein accordingly. In prior responses to comments, NMFS has found that the SAR is the best available scientific evidence with respect to NARW population estimates (see *e.g.*, 87 FR 25452). We find no reason to reconsider or depart from this.

Moreover, the draft 2022 SARs report the same NARW abundance estimate (336) cited by Oceana in its public comment. We further note that this change in abundance estimate does not change the estimated take of NARWs or authorized take numbers, nor does it affect our ability to make the required findings under the MMPA for TerraSond's survey activities.

In sum, NMFS considered the best available scientific evidence regarding both recent habitat usage patterns for the study area and up-to-date seasonality information in the notice of the proposed IHA, including consideration of existing biologically important areas (BIAs) and densities provided by Roberts and Halpin (2022). While the commenter has suggested that NMFS consider best available scientific evidence for recent habitat usage patterns and seasonality, the commenter has not offered any additional scientific information that it suggests should be considered best available scientific evidence.

Comment: Oceana noted that chronic stressors are an emerging concern for NARW conservation and recovery, and stated that chronic stress may result in energetic effects for NARWs. Oceana suggested that NMFS has not fully considered both the use of the area and the effects of both acute and chronic stressors on the health and fitness of NARWs, as disturbance responses in NARWs could lead to chronic stress or habitat displacement, leading to an overall decline in their health and fitness.

Response: NMFS agrees with Oceana that both acute and chronic stressors are of concern for NARW conservation and recovery. We recognize that acute stress from acoustic exposure is one potential impact of these surveys, and that chronic stress can have fitness, reproductive, *etc.* impacts at the population-level scale. NMFS has carefully reviewed the best available scientific information in assessing impacts to marine mammals, and recognizes that the surveys have the potential to impact marine mammals

through behavioral effects, stress responses, and auditory masking. However, NMFS does not expect that the generally short-term, intermittent, and transitory marine site characterization survey activities planned by TerraSond will create conditions of acute or chronic acoustic exposure leading to long-term physiological stress responses in marine mammals. NMFS has prescribed a robust suite of mitigation measures, including extended distance shutdowns for NARW, that are expected to further reduce the duration and intensity of acoustic exposure, while limiting the potential severity of any possible behavioral disruption. The potential for chronic stress was evaluated in making the determinations presented in NMFS' negligible impact analyses. Because NARW generally use this location in a transitory manner, specifically for migration, any potential impacts from these surveys are lessened for other behaviors due to the brief periods where exposure is possible. Thus, the transitory nature of occurrence of NARWs as they migrate means it is unlikely for any exposure to cause chronic effects, as TerraSond's planned survey area and ensonified zones are small relative to the overall migratory corridor. As such, NMFS does not expect acute or cumulative stress to be a detrimental factor to NARWs from TerraSond's described survey activities.

Lastly, NMFS does not find that the effects of TerraSond's survey may contribute to stunted growth rates as suggested by Oceana's comments. The activities associated with TerraSond's survey are outside the scope of activities described in the Stewart et al. (2021) paper, which finds that entanglements in fishing gear are associated with shorter whales. There is no evidence suggesting that the survey activities considered herein could have energetic effects similar to those caused by entanglement in fishing gear. Therefore, NMFS does not expect stunted growth rates to result from TerraSond's described survey activities.

Comment: Oceana suggests that all vessels associated with the proposed survey should be required to carry and use protected species observers (PSOs), and that PSOs complement their survey efforts using additional technologies, such as infrared detection devices when in low-light conditions.

Response: NMFS finds that it is unnecessary for all survey vessels to use PSOs. PSOs are generally reserved for use onboard acoustic source vessels, where PSOs are responsible for conducting observations, notifying the crew of the need to implement

mitigation measures, and recording data. In circumstances similar to those associated with TerraSond's proposed activities, watchstanders are fully capable of conducting watch for purposes of avoiding vessel strike of any objects, including marine mammals. NMFS does, however, agree with Oceana about the use of night vision devices. As such, a requirement to utilize at least one thermal (infrared) imaging device during low-light conditions was included in the proposed **Federal Register** notice. That requirement is included as a requirement of the issued IHA.

Comment: Oceana recommends that NMFS restrict all vessels of all sizes associated with the proposed survey activities to speeds less than 10 kn (18.5 km/hour) at all times due to the risk of vessel strikes to NARWs and other large whales.

Response: While NMFS acknowledges that vessel strikes can result in injury or mortality, we have analyzed the potential for vessel strike resulting from TerraSond's activity and have determined that based on the nature of the activity and the required mitigation measures specific to vessel strike avoidance included in the IHA, potential for vessel strike is so low as to be discountable. The required mitigation measures, all of which were included in the proposed IHA and are now required in the final IHA, include: (1) a requirement that all vessel operators comply with 10 kn (18.5 km/hour) or less speed restrictions in any SMA, DMA or Slow Zone while underway, and check daily for information regarding the establishment of mandatory or voluntary vessel strike avoidance areas (SMAs, DMAs, Slow Zones) and information regarding NARW sighting locations; (2) a requirement that all vessels greater than or equal to 19.8 m in overall length operating from November 1 through April 30 operate at speeds of 10 kn (18.5 km/hour) or less; (3) a requirement that all vessel operators reduce vessel speed to 10 kn (18.5 km/hour) or less when any large whale, any mother/calf pairs, pods, or large assemblages of non-delphinid cetaceans are observed near the vessel; (4) a requirement that all survey vessels maintain a separation distance of 500 m or greater from any Endangered Species Act (ESA)-listed whales or other unidentified large marine mammals visible at the surface while underway; (5) a requirement that, if underway, vessels must steer a course away from any sighted ESA-listed whale at 10 kn or less until the 500 m minimum separation distance has been established; (6) a requirement that, if an

ESA-listed whale is sighted in a vessel's path, or within 500 m of an underway vessel, the underway vessel must reduce speed and shift the engine to neutral; (7) a requirement that all vessels underway must maintain a minimum separation distance of 100 m from all non-ESA-listed baleen whales; and, (8) a requirement that all vessels underway must, to the maximum extent practicable, attempt to maintain a minimum separation distance of 50 m from all other marine mammals, with an understanding that at times this may not be possible (e.g., for animals that approach the vessel). We have determined that the vessel strike avoidance measures in the IHA are sufficient to ensure the least practicable adverse impact on species or stocks and their habitat. Furthermore, no documented vessel strikes have occurred for any marine site characterization surveys, which were issued IHAs from NMFS during the survey activities themselves or while transiting to and from survey sites.

Comment: Oceana suggests that NMFS require vessels maintain a separation distance of at least 500 m from NARWs at all times.

Response: NMFS agrees with Oceana regarding this suggestion and a requirement to maintain a separation distance of at least 500 m from NARWs at all times was included in the proposed **Federal Register** notice and was included as a requirement in the issued IHA.

Comment: Oceana recommended that the IHA should require all vessels supporting site characterization to be equipped with and use Class A Automatic Identification System (AIS) devices at all times while on the water. Oceana suggested this requirement should apply to all vessels, regardless of size, associated with the survey.

Response: NMFS is generally supportive of the idea that vessels involved with survey activities be equipped with and use Class A AIS devices at all times while on the water. Indeed, there is a precedent for NMFS requiring such a stipulation for geophysical surveys in the Atlantic Ocean (83 FR 63268, December 7, 2018); however, these seismic surveys carried the potential for much more significant impacts than the marine site characterization surveys planned by TerraSond. Given the comparatively small footprint of potential effects and correspondingly low level of concern regarding HRG survey activities, NMFS has determined that the operational costs associated with a requirement to so equip vessels not otherwise required to carry AIS are not warranted under the

MMPA's least practicable adverse impact standard.

Comment: Oceana asserts that the IHA must include requirements to hold all vessels associated with site characterization surveys accountable to the IHA requirements, including vessels owned by the developer, contractors, employees, and others regardless of ownership, operator, and contract. They state that exceptions and exemptions will create enforcement uncertainty and incentives to evade regulations through reclassification and redesignation. They recommend that NMFS simplify this by requiring all vessels to abide by the same requirements, regardless of size, ownership, function, contract, or other specifics.

Response: NMFS agrees with Oceana and the proposed IHA and final IHA has general conditions to hold TerraSond and its designees (including vessel operators and other personnel) accountable while performing operations under the authority of the IHA. The plain language of the IHA indicates that the conditions contained therein apply to TerraSond and its designees. The IHA requires that a copy of the IHA must be in the possession of TerraSond, the vessel operators, the lead PSO, and any other relevant designees of TerraSond operating under the authority of this IHA. The IHA also states that TerraSond must ensure that the vessel operator and other relevant vessel personnel, including the PSO team, are briefed on all responsibilities, communication procedures, marine mammal monitoring protocols, operational procedures, and IHA requirements prior to the start of survey activity, and when relevant new personnel join the survey operations.

Comment: Oceana stated that the IHA must include a requirement for all phases of the survey to subscribe to the highest level of transparency, including frequent reporting to federal agencies. Oceana recommends requirements to report all visual and acoustic detections of NARWs and any dead, injured, or entangled marine mammals to NMFS or the Coast Guard as soon as possible and no later than the end of the PSO shift, and also states that to foster stakeholder relationships and allow public engagement and oversight of the permitting, the IHA should require all reports and data to be accessible on a publicly available website.

Response: NMFS agrees with the need for reporting and, indeed, the MMPA calls for IHAs to incorporate reporting requirements. As included in the proposed IHA, the final IHA includes requirements for reporting that supports Oceana's recommendations. TerraSond

is required to submit a monitoring report to NMFS within 90 days after completion of survey activities that fully documents the methods and monitoring protocols, summarizes the data recorded during monitoring. PSO datasheets or raw sightings data must also be provided with the draft and final monitoring report.

Further, the draft IHA and final IHA stipulate that if a NARW is observed at any time by any survey vessels, during surveys or during vessel transit, TerraSond must immediately report sighting information to the NMFS North Atlantic Right Whale Sighting Advisory System within two hours of occurrence, when practicable, or no later than 24 hours after occurrence. TerraSond may also report the sighting to the U.S. Coast Guard. Additionally, TerraSond must report any discoveries of injured or dead marine mammals to the Office of Protected Resources, NMFS, and to the New England/Mid-Atlantic Regional Stranding Coordinator as soon as feasible. This includes entangled animals. All reports and associated data submitted to NMFS are included on the website for public inspection.

Daily visual and acoustic detections of NARWs and other large whale species along the Eastern Seaboard, as well as Slow Zone locations, are publicly available on WhaleMap (<https://whalemap.org/WhaleMap/>). Further, recent acoustic detections of NARWs and other large whale species are available to the public on NOAA's Passive Acoustic Cetacean Map website <https://apps-nefsc.fisheries.noaa.gov/pacm/#/narw>.

Comment: Oceana recommended that NMFS require a visual clearance zone of at least 1,000 m for NARWs around each vessel, and also require an acoustic clearance and exclusion zone of at least 1,000 m for NARWs. In contrast, DNREC commended the use of exclusion zones as proposed by NMFS, but also noted its support for the use of passive acoustic monitoring (PAM) as a supplementary monitoring technique.

Response: NMFS notes that the 500 m shutdown zone for NARWs exceeds the modeled distance to the largest 160 dB Level B harassment isopleth (141 m during sparker use) by a substantial margin. Oceana does not provide a compelling rationale for why the shutdown zone should be even larger. Given that these surveys are relatively low impact and that, regardless, NMFS has prescribed a NARW shutdown zone that is significantly larger (500 m) than the conservatively estimated largest harassment zone (141 m), NMFS has determined that the shutdown zone is appropriate. Further, Level A

harassment is not expected to result even in the absence of mitigation, given the characteristics of the sources planned for use.

Regarding the use of acoustic monitoring to implement the exclusion zones, NMFS does not anticipate that acoustic monitoring would be effective for a variety of reasons discussed below and therefore has not required it in this IHA. As described in the Mitigation section, NMFS has determined that the prescribed mitigation requirements are sufficient to effect the least practicable adverse impact on all affected species or stocks.

The commenters do not explain why they expect that PAM would be effective in detecting vocalizing mysticetes, nor does NMFS agree that this measure is warranted, as it is not expected to be effective for use in detecting the species of concern. It is generally accepted that, even in the absence of additional acoustic sources, using a towed passive acoustic sensor to detect baleen whales (including NARWs) is not typically effective because the noise from the vessel, the flow noise, and the cable noise are in the same frequency band and will mask the vast majority of baleen whale calls. Vessels produce low-frequency noise, primarily through propeller cavitation, with main energy in the 5–300 hertz (Hz) frequency range. Source levels range from about 140 to 195 decibel (dB) referenced to 1 micropascal (re 1 μ Pa) at 1 m (NRC, 2003; Hildebrand, 2009), depending on factors such as ship type, load, and speed, and ship hull and propeller design. Studies of vessel noise show that it appears to increase background noise levels in the 71–224 Hz range by 10–13 dB (Hatch *et al.* 2012; McKenna *et al.* 2012; Rolland *et al.* 2012). PAM systems employ hydrophones towed in streamer cables approximately 500 m behind a vessel. Noise from water flow around the cables and from strumming of the cables themselves is also low frequency and typically masks signals in the same range. Experienced PAM operators participating in a recent workshop (Thode *et al.*, 2017) emphasized that a PAM operation could easily report no acoustic encounters, depending on species present, simply because background noise levels rendered any acoustic detection impossible. The same workshop report stated that a typical eight-element array towed 500 m behind a vessel could be expected to detect delphinids, sperm whales, and beaked whales at the required range, but not baleen whales, due to expected background noise levels (including seismic noise, vessel noise, and flow noise).

Given that the effects to marine mammals from the types of surveys authorized in this IHA are expected to be limited to low level behavioral harassment even in the absence of mitigation, the limited additional benefit anticipated by adding this detection method (especially for NARWs and other low frequency cetaceans, species for which PAM has limited efficacy), and the cost and impracticability of implementing a full-time PAM program, we have determined the current requirements for visual monitoring are sufficient to ensure the least practicable adverse impact on the affected species or stocks and their habitat. NMFS has previously provided discussions on why PAM is not a required monitoring measure during HRG survey IHAs in past **Federal Register** notices (see 86 FR 21289, April 22, 2021, and 87 FR 13975, March 11, 2022, for examples).

Comment: SELC noted that, subsequent to NMFS' publication of the notice of proposed IHA, BOEM made available for public comment eight draft WEAs, and that these draft WEAs, and that these draft WEAs represent a smaller subset of the BOEM Central Atlantic Call Area that formed the basis for TerraSond's planned survey activity. SELC expressed concern regarding the potential that TerraSond's planned survey activity covers an area larger than the draft WEAs. Relatedly, SELC asserted that the same area could be subject to repeated survey efforts by different companies (characterizing these hypothetical repeated surveys as "redundant") and expressed concern regarding the potential for cumulative impacts of the activities on NARW.

Response: We first note that BOEM has not yet finalized its draft WEAs following closure of the public comment period on December 16, 2022. Therefore, it is possible that the draft WEAs may yet be expanded to an area more closely approaching the initial Call Area, and NMFS cannot make any judgment regarding the need for, or likelihood of, TerraSond's proposed survey efforts within the Central Atlantic portion of its planned efforts. As noted previously, however, NMFS expects that the amount of survey effort ultimately conducted by TerraSond will be dictated by commercial interest. As such, NMFS considers it unlikely that TerraSond would in fact conduct survey effort over a significantly larger area than would be available for wind energy development. Regardless, it is not within NMFS' purview to judge the merits of an applicant's specified activity. NMFS cannot arbitrarily limit planned effort and has no legitimate

means of changing the specified activity absent a conclusion that the activity would have more than a negligible impact. However, NMFS has made the necessary findings under the MMPA for issuance of this IHA.

Regarding the suggestion that future surveys could be conducted over the same area by other entities, NMFS declines to speculate as to the likelihood that such survey effort may be conducted. Neither the MMPA nor NMFS' codified implementing regulations call for consideration of other unrelated activities and their impacts on populations. Regardless, while NMFS shares the commenter's concerns regarding NARW, the potential additional surveys described by SELC cannot at this time be considered to be reasonably foreseeable activities.

Comment: SELC expresses concern regarding what it characterizes as inadequate protections for NARW, and reiterates prior recommendations for NMFS to reinstate its 2021 ESA Programmatic Informal Consultation.

Response: NMFS disagrees with SELC's assertion that existing mitigation protections for NARW are inadequate. SELC does not provide specific recommendations for requirements that it would deem adequate. However, we note that TerraSond is required to implement clearance and exclusion zones of 500 m for NARW. This 500 m zone exceeds the modeled distance to the largest 160 dB Level B harassment isopleth (141 m during sparker use) by a substantial margin. Further, Level A harassment (auditory injury) is not expected to result even in the absence of mitigation, given the characteristics of the sources planned for use. We further note that reinstitution of ESA section 7 consultation is not warranted, as none of the reinstitution triggers listed in NMFS' 2021 programmatic consultation have been met.

Comment: DNREC recommended that TerraSond consider adopting NMFS' proposed changes to the NARW vessel speed rule to further reduce the likelihood of vessel collisions.

Response: As discussed in a previous comment response, NMFS requires substantial measures towards minimizing the risk of vessel strike and has determined that no vessel strike is anticipated to occur.

Description of Marine Mammals in the Area of Specified Activities

Sections 3 and 4 of the application summarize available information regarding status and trends, distribution and habitat preferences, and behavior and life history of the potentially affected species. NMFS fully considered

all of this information, and we refer the reader to these descriptions, incorporated here by reference, instead of reprinting the information.

Additional information regarding population trends and threats may be found in NMFS' Stock Assessment Reports (SARs; www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments) and more general information about these species (e.g., physical and behavioral descriptions) may be found on NMFS' website (<https://www.fisheries.noaa.gov/find-species>).

Table 2 lists all species or stocks for which take is expected and authorized for this activity, and summarizes information related to the population or stock, including regulatory status under

the MMPA and Endangered Species Act (ESA) and potential biological removal (PBR), where known. PBR is defined by the MMPA as the maximum number of animals, not including natural mortalities, that may be removed from a marine mammal stock while allowing that stock to reach or maintain its optimum sustainable population (as described in NMFS' SARs). While no serious injury or mortality is expected to occur, PBR and annual serious injury and mortality from anthropogenic sources are included here as gross indicators of the status of the species or stocks and other threats.

Marine mammal abundance estimates presented in this document represent the total number of individuals that make up a given stock or the total

number estimated within a particular study or survey area. NMFS' stock abundance estimates for most species represent the total estimate of individuals within the geographic area, if known, that comprises that stock. For some species, this geographic area may extend beyond U.S. waters. All stocks managed under the MMPA in this region are assessed in NMFS' U.S. Atlantic and Gulf of Mexico SARs. All values presented in Table 2 are the most recent available at the time of publication (draft 2022 SARs) and are available online at: <https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessment-reports>.

TABLE 2—SPECIES LIKELY IMPACTED BY THE SPECIFIED ACTIVITIES

Common name	Scientific name	Stock	ESA/ MMPA status; strategic (Y/N) ¹	Stock abundance (CV, N _{min} , most recent abundance survey) ²	PBR	Annual M/SI ³
Order Artiodactyla—Infraorder Cetacea—Mysticeti (baleen whales)						
Family Balaenidae: North Atlantic right whale	<i>Eubalaena glacialis</i>	Western North Atlantic (WNA)	E/D; Y	338 (0; 332; 2020)	0.7	8.1
Family Balaenopteridae (rorquals):						
Humpback whale	<i>Megaptera novaeangliae</i>	Gulf of Maine	-/-; Y	1,393 (0; 1,380; 2016)	22	12.15
Minke whale	<i>Balaenoptera acutorostrata</i>	Canadian East Coast	-/-; N	21,968 (0.31; 17,002; 2016) ..	170	10.6
Sei whale	<i>Balaenoptera borealis</i>	Nova Scotia	E/D; Y	6,292 (1.02; 3,098; 2016)	6.2	0.8
Fin whale	<i>Balaenoptera physalus</i>	WNA	E/D; Y	6,802 (0.24; 5,573; 2016)	11	1.8
Odontoceti (toothed whales, dolphins, and porpoises)						
Family Ziphiidae (beaked whales):						
Cuvier's beaked whale	<i>Ziphius cavirostris</i>	WNA	-/-; N	5,744 (0.36; 4,282; 2016)	43	0.2
Mesoplodont beaked whales ⁵ .	<i>Mesoplodon</i> spp.	WNA	-/-; N	10,107 (0.27; 8,085; 2016)	81	0.4
Family Physeteridae: Sperm whale	<i>Physeter macrocephalus</i>	North Atlantic	E/D; Y	4,349 (0.28; 3,451; 2016)	3.9	0
Family Delphinidae:						
Rough-toothed dolphin	<i>Steno bredanensis</i>	WNA	-/-; N	136 (1.0; 67; 2016)	0.7	0
Bottlenose dolphin	<i>Tursiops truncatus</i>	WNA Offshore	-/-; N	62,851 (0.23; 51,914; 2016) ..	519	28
		WNA Northern Migratory Coastal.	-D;Y	6,639 (0.41; 4,759; 2016)	48	12.2–21.5
Atlantic spotted dolphin ...	<i>Stenella frontalis</i>	WNA	-/-; N	39,921 (0.27; 32,032; 2016) ..	320	0
Common dolphin	<i>Delphinus delphis</i>	WNA	-/-; N	172,974 (0.21; 145,216; 2016)	1,452	390
Atlantic white-sided dol- phin.	<i>Lagenorhynchus acutus</i>	WNA	-/-; N	93,233 (0.71; 54,443; 2016) ..	544	27
Risso's dolphin	<i>Grampus griseus</i>	WNA	-/-; N	35,215 (0.19; 30,051; 2016) ..	301	34
Short finned pilot whale ...	<i>Globicephala macrorhynchus</i>	WNA	-/-; N	28,924 (0.24; 23,637; 2016) ..	236	136
Long-finned pilot whale ...	<i>G. melas</i>	WNA	-/-; N	39,215 (0.30; 30,627; 2016) ..	306	9
Family Phocoenidae (por- poises):						
Harbor porpoise	<i>Phocoena phocoena</i>	Gulf of Maine/Bay of Fundy ...	-/-; N	95,543 (0.31; 74,034; 2016) ..	851	164
Order Carnivora—Pinnipedia						
Family Phocidae (earless seals):						
Gray seal ⁴	<i>Halichoerus grypus</i>	WNA	-/-; N	27,300 (0.22; 22,785; 2016) ..	1,458	4,452
Harbor seal	<i>Phoca vitulina</i>	WNA	-/-; N	61,336 (0.08; 57,637; 2018) ..	1,729	339

¹ ESA status: Endangered (E), Threatened (T)/MMPA status: Depleted (D). A dash (-) indicates that the species is not listed under the ESA or designated as depleted under the MMPA. Under the MMPA, a strategic stock is one for which the level of direct human-caused mortality exceeds PBR or which is determined to be declining and likely to be listed under the ESA within the foreseeable future. Any species or stock listed under the ESA is automatically designated under the MMPA as depleted and as a strategic stock.

² NMFS marine mammal stock assessment reports online at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments. CV is coefficient of variation; N_{min} is the minimum estimate of stock abundance. In some cases, CV is not applicable.

³ These mortality and serious injury (M/SI) values, found in NMFS' SARs, represent annual levels of human-caused mortality plus serious injury from all sources combined (e.g., commercial fisheries, ship strike).

⁴ NMFS' stock abundance estimate (and associated PBR value) applies to U.S. population only. Total stock abundance (including animals in Canada) is approximately 451,600. The annual M/SI value given is for the total stock.

⁵ Mesoplodont beaked whales in the U.S. Atlantic include the Gervais beaked whale (*M. europaeus*), Blainville's beaked whale (*M. densirostris*), Sowerby's beaked whale (*M. bidens*), and True's beaked whale (*M. mirus*). These species are difficult to identify to the species level at sea; therefore, much of the available characterization for beaked whales is to genus level only and the species are managed together as a stock.

A detailed description of the species likely to be affected by TerraSond's activities, including information regarding population trends, threats, and local occurrence, was provided in the **Federal Register** notice for the proposed IHA (87 FR 66658; November 4, 2022); since that time, we are not aware of any changes in the status of these species and stocks; therefore, detailed descriptions are not provided here. Please refer to that **Federal Register** notice for these descriptions. Please also refer to NMFS' website (<https://www.fisheries.noaa.gov/find-species>) for generalized species accounts.

Marine Mammal Hearing

Hearing is the most important sensory modality for marine mammals underwater, and exposure to anthropogenic sound can have deleterious effects. To appropriately assess the potential effects of exposure to sound, it is necessary to understand the frequency ranges marine mammals are able to hear. Not all marine mammal species have equal hearing capabilities (e.g., Richardson *et al.*, 1995; Wartok and Ketten, 1999; Au and Hastings, 2008). To reflect this, Southall *et al.* (2007, 2019) recommended that marine mammals be divided into hearing groups based on directly measured (behavioral or auditory evoked potential techniques) or estimated hearing ranges

(behavioral response data, anatomical modeling, *etc.*). Note that no direct measurements of hearing ability have been successfully completed for mysticetes (*i.e.*, low-frequency cetaceans). Subsequently, NMFS (2018) described generalized hearing ranges for these marine mammal hearing groups. Generalized hearing ranges were chosen based on the approximately 65 dB threshold from the normalized composite audiograms, with the exception for lower limits for low-frequency cetaceans where the lower bound was deemed to be biologically implausible and the lower bound from Southall *et al.* (2007) retained. Marine mammal hearing groups and their associated hearing ranges are provided in Table 3.

TABLE 3—MARINE MAMMAL HEARING GROUPS (NMFS, 2018)

Hearing group	Generalized hearing range *
Low-frequency (LF) cetaceans (baleen whales)	7 Hz to 35 kHz.
Mid-frequency (MF) cetaceans (dolphins, toothed whales, beaked whales, bottlenose whales)	150 Hz to 160 kHz.
High-frequency (HF) cetaceans (true porpoises, <i>Kogia</i> , river dolphins, Cephalorhynchid, <i>Lagenorhynchus cruciger</i> & <i>L. australis</i>)	275 Hz to 160 kHz.
Phocid pinnipeds (PW) (underwater) (true seals)	50 Hz to 86 kHz.
Otariid pinnipeds (OW) (underwater) (sea lions and fur seals)	60 Hz to 39 kHz.

* Represents the generalized hearing range for the entire group as a composite (*i.e.*, all species within the group), where individual species' hearing ranges are typically not as broad. Generalized hearing range chosen based on ~65 dB threshold from normalized composite audiogram, with the exception for lower limits for LF cetaceans (Southall *et al.* 2007) and PW pinniped (approximation).

The pinniped functional hearing group was modified from Southall *et al.* (2007) on the basis of data indicating that phocid species have consistently demonstrated an extended frequency range of hearing compared to otariids, especially in the higher frequency range (Hemilä *et al.*, 2006; Kastelein *et al.*, 2009; Reichmuth and Holt, 2013).

For more detail concerning these groups and associated frequency ranges, please see NMFS (2018) for a review of available information.

Potential Effects of Specified Activities on Marine Mammals and Their Habitat

The effects of underwater noise from the deployed acoustic sources have the potential to result in behavioral harassment of marine mammals in the vicinity of the study area. The **Federal Register** notice for the proposed IHA (87 FR 66658; November 4, 2022) included a discussion of the effects of anthropogenic noise on marine mammals and their habitat, therefore that information is not repeated here; please refer to the **Federal Register** notice for that information.

Estimated Take

This section provides an estimate of the number of incidental takes authorized through the IHA, which will inform both NMFS' consideration of "small numbers," and the negligible impact determinations.

Harassment is the only type of take expected to result from these activities. Except with respect to certain activities not pertinent here, section 3(18) of the MMPA defines "harassment" as any act of pursuit, torment, or annoyance, which (i) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment); or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment).

Authorized takes are by Level B harassment only, in the form of disruption of behavioral patterns for individual marine mammals resulting from exposure to sound produced by the sparker. Based primarily on the

characteristics of the signals produced by the acoustic sources planned for use, Level A harassment is neither anticipated (even absent mitigation), nor authorized. Consideration of the anticipated effectiveness of the mitigation measures (*i.e.*, shutdown zones and shutdown measures), discussed in detail below in the Mitigation section, further strengthens the conclusion that Level A harassment is not a reasonably anticipated outcome of the survey activity. As described previously, no serious injury or mortality is anticipated or authorized for this activity. Below we describe how the take numbers are estimated.

For acoustic impacts, generally speaking, we estimate take by considering: (1) acoustic thresholds above which NMFS believes the best available science indicates marine mammals will be behaviorally harassed or incur some degree of permanent hearing impairment; (2) the area or volume of water that will be ensonified above these levels in a day; (3) the density or occurrence of marine mammals within these ensonified areas;

and, (4) the number of days of activities. We note that while these factors can contribute to a basic calculation to provide an initial prediction of potential takes, additional information that can qualitatively inform take estimates is also sometimes available (e.g., previous monitoring results or average group size). Below, we describe the factors considered here in more detail and present the take estimates.

Acoustic Thresholds

NMFS recommends the use of acoustic thresholds that identify the received level of underwater sound above which exposed marine mammals would be reasonably expected to be behaviorally harassed (equated to Level B harassment) or to incur PTS of some degree (equated to Level A harassment).

Level B Harassment—Though significantly driven by received level, the onset of behavioral disturbance from anthropogenic noise exposure is also informed to varying degrees by other factors related to the source or exposure context (e.g., frequency, predictability, duty cycle, duration of the exposure, signal-to-noise ratio, distance to the source), the environment (e.g., bathymetry, other noises in the area, predators in the area), and the receiving animals (hearing, motivation, experience, demography, life stage, depth) and can be difficult to predict (e.g., Southall *et al.*, 2007, 2021, Ellison *et al.*, 2012). Based on what the available science indicates and the practical need to use a threshold based on a metric that is both predictable and measurable for most activities, NMFS typically uses a generalized acoustic threshold based on received level to estimate the onset of behavioral harassment. NMFS generally predicts that marine mammals are likely to be behaviorally harassed in a manner considered to be Level B harassment when exposed to underwater anthropogenic noise above root-mean-squared pressure received levels (RMS SPL) of 160 dB (re 1 μ Pa) for impulsive (e.g., seismic airguns) or intermittent (e.g., scientific sonar) sources. Generally speaking, Level B harassment take estimates based on these behavioral harassment thresholds are expected to include any likely takes by temporary threshold shift (TTS) as, in most cases, the likelihood of TTS occurs at distances from the source less than those at which behavioral harassment is likely. TTS of a sufficient degree can manifest as behavioral harassment, as reduced hearing sensitivity and the potential reduced opportunities to detect important signals (conspecific communication, predators, prey) may

result in changes in behavior patterns that would not otherwise occur.

TerraSond's planned activity includes the use of impulsive (sparker) sources, and therefore the RMS SPL threshold of 160 dB re 1 μ Pa is applicable.

Level A harassment—NMFS' Technical Guidance for Assessing the Effects of Anthropogenic Sound on Marine Mammal Hearing (Version 2.0) (Technical Guidance, 2018) identifies dual criteria to assess auditory injury (Level A harassment) to five different marine mammal groups (based on hearing sensitivity) as a result of exposure to noise from two different types of sources (impulsive or non-impulsive). The references, analysis, and methodology used in the development of the thresholds are described in NMFS' 2018 Technical Guidance, which may be accessed at: www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-acoustic-technical-guidance.

TerraSond's planned activity includes the use of impulsive (i.e., sparkers) sources. However, as discussed above, NMFS has concluded that Level A harassment is not a reasonably likely outcome for marine mammals exposed to noise through use of the sources planned for use here, and the potential for Level A harassment is not evaluated further in this document. Please see TerraSond's application for details of a quantitative exposure analysis exercise, i.e., calculated Level A harassment isopleths and estimated Level A harassment exposures. TerraSond did not request authorization of take by Level A harassment, and no take by Level A harassment is authorized by NMFS.

Ensonified Area

Here, we describe operational and environmental parameters of the activity that are used in estimating the area ensonified above the acoustic thresholds, including source levels and transmission loss coefficient.

NMFS has developed a user-friendly methodology for estimating the extent of the Level B harassment isopleths associated with relevant HRG survey equipment (NMFS, 2020). This methodology incorporates frequency and directionality (when relevant) to refine estimated ensonified zones. For acoustic sources that operate with different beamwidths, the maximum beamwidth is used, and the lowest frequency of the source is used when calculating the frequency-dependent absorption coefficient (Table 1). The sparkers planned for use by TerraSond are omnidirectional and, therefore,

beamwidth does not factor into the calculations.

NMFS considers the data provided by Crocker and Fratantonio (2016) to represent the best available information on source levels associated with HRG equipment and, therefore, recommends that source levels provided by Crocker and Fratantonio (2016) be incorporated in the method described above to estimate isopleth distances to harassment thresholds. In cases when the source level for a specific type of HRG equipment is not provided in Crocker and Fratantonio (2016), NMFS recommends that either the source levels provided by the manufacturer be used, or, in instances where source levels provided by the manufacturer are unavailable or unreliable, a proxy from Crocker and Fratantonio (2016) be used instead. Table 1 provides relevant source parameters used in the calculations. Results of modeling using the methodology described above produced an estimated Level B harassment isopleth of 141 m.

Central Atlantic—Phase 1, Alternative 1 would involve a single towed source, and daily ensonified area was calculated as follows: $(100 \text{ km} \times 2 \times 0.141 \text{ km}) + (\pi \times (0.141^2 \text{ km}))$. Distributing the 58,607 km of Phase 1, Alternative 1 survey activity across the 12-month period of anticipated activity results in approximately 48.8 survey days per month, which was multiplied by the daily ensonified area to give a monthly ensonified area of 1,380 km. Phase 1, Alternative 2 would involve three towed sources with 150 m horizontal separation between them. Daily ensonified area was calculated as follows: $(100 \text{ km} \times 2 \times (0.141 \text{ km} + 0.15 \text{ km}) + (\pi \times (0.291^2 \text{ km})))$. Distributing the 19,536 km of Phase 1, Alternative 2 survey activity across the 12-month period of anticipated activity results in approximately 16.3 survey days per month, which was multiplied by the daily ensonified area to give a monthly ensonified area of 952 km². Because only one of the alternatives would ultimately be selected, the monthly ensonified area associated with Alternative 1 was used to estimate potential marine mammal take for Phase 1.

Phase 2 involves two towed sources with 30 m horizontal separation between them. Daily ensonified area was calculated as follows: $(100 \text{ km} \times 2 \times (0.141 \text{ km} + 0.015 \text{ km}) + (\pi \times (0.156^2 \text{ km})))$. Distributing the 46,573 km of Phase 2 survey activity across the 12-month period of anticipated activity results in approximately 38.8 survey days per month, which was multiplied

by the daily ensonified area to give a monthly ensonified area of 1,214 km².

New York Bight—Phase 1 involves a single towed source, and ensonified area was calculated in the same manner as described above for Central Atlantic Phase 1, Alternative 1. Distributing the 14,833 km of Phase 1 survey activity across the 12-month period of anticipated activity results in approximately 12.4 survey days per month, which was multiplied by the daily ensonified area to give a monthly ensonified area of 349 km². Phases 2 and 3 each use a dual source configuration with a horizontal separation distance of 30 m between the sources, and ensonified area was calculated in the same manner as described above for Central Atlantic Phase 2. For Phase 2, TerraSond assumes that there would be two days of survey activity, giving a total ensonified area of 62.6 km². Distributing the combined 23,311 km of Phase 3 survey activity across the 12-month period of anticipated activity results in approximately 19.4 survey days per month, which was multiplied by the daily ensonified area to give a monthly ensonified area of 608 km².

Marine Mammal Occurrence

In this section we provide information about the occurrence of marine mammals, including density or other relevant information, that will inform the take calculations.

Habitat-based density models produced by the Duke University Marine Geospatial Ecology Laboratory (Roberts and Halpin, 2022) represent the best available information regarding marine mammal densities in the survey area. These density data incorporate aerial and shipboard line-transect survey data from NMFS and other

organizations and incorporate data from numerous physiographic and dynamic oceanographic and biological covariates, and control for the influence of sea state, group size, availability bias, and perception bias on the probability of making a sighting. These density models were originally developed for all cetacean taxa in the U.S. Atlantic (Roberts *et al.*, 2016). In subsequent years, the models have been updated based on additional data as well as certain methodological improvements. More information is available online at <https://seamap.env.duke.edu/models/Duke/EC/>. Marine mammal density estimates in the survey area (animals/km²) were obtained using the most recent model results for all taxa.

In order to select a representative sample of grid cells in and near each survey area, TerraSond created a 10-km wide perimeter around each area (Figures 1 and 2) in a Geographic Information System (GIS). The perimeter was then used to select grid cells in and around each area containing the monthly or annual estimates for each species. The average monthly abundance for each species in each area was calculated as the mean value of the selected grid cells in each month. See Tables 10 and 11 in TerraSond's application for density values used in the analysis.

Density information is presented for seals generically. In order to generate species-specific density values, TerraSond multiplied seal density values by the proportion of total SAR-estimated seal abundance attributed to each species. Roberts and Halpin (2022) similarly provide generic density information for pilot whales and bottlenose dolphins. In the Central Atlantic survey area, where both species of pilot whales could be encountered,

TerraSond requested that the density-based take estimate be divided equally across the two species. In the New York Bight survey area, only the long-finned pilot whale is expected to be present, and all estimated takes are attributed to that species. For bottlenose dolphins, although the northern coastal migratory stock could be present in the region, all survey effort is in sufficiently deep water (20–65 m) that we assume all potential bottlenose dolphin takes are appropriately assigned to the offshore stock.

Take Estimation

Here we describe how the information provided above is synthesized to produce a quantitative estimate of the take that is reasonably likely to occur and is authorized.

Estimates of the potential number of takes by Level B harassment were calculated by multiplying the monthly density for each species in the respective survey areas (Central Atlantic and New York Bight) by the respective monthly ensonified area for each Phase and then summing across the 12 months. TerraSond evaluated monitoring reports from the vicinity of the survey areas, finding that the common dolphin estimated take number for the New York Bight survey area may be underestimated. Based on these observational data, TerraSond assumes that 16 common dolphins may be encountered within the harassment zone on each survey data. Based on the planned 385 survey days in the New York Bight survey area, this produces an estimate of 6,160 takes. This larger value is substituted for the density-based take estimate for common dolphins. Table 4 provides information about the take estimates and authorized take.

TABLE 4—ESTIMATED TAKE NUMBERS AND TOTAL AUTHORIZED TAKE

Species	Estimated take— Central Atlantic		Estimated take— New York Bight			Authorized take	Percent abundance
	Phase 1	Phase 2	Phase 1	Phase 2	Phase 3		
North Atlantic right whale	5.1	4.5	1.9	0.0	3.3	15	4.4
Humpback whale	21.6	19.0	4.0	0.1	7.0	52	3.7
Minke whale	30.7	27.0	14.7	0.2	25.5	98	0.4
Sei whale	4.9	4.3	1.2	0.0	2.2	13	0.2
Fin whale	44.1	38.8	8.0	0.1	14.0	105	1.5
Cuvier's beaked whale	29.1	25.6	0	0	0	55	1.0
Mesoplodont beaked whales	5.7	5.0	0	0	0	11	0.1
Sperm whale	16.0	14.1	0.6	0	1.1	32	0.7
Rough-toothed dolphin ¹	2.0	1.6	0	0	0	10	7.4
Bottlenose dolphin	1,427.7	1,255.6	116.6	1.8	202.8	3,005	4.8
Atlantic spotted dolphin	605.6	532.6	20.9	0.3	36.3	1,196	3.0
Common dolphin ²	5,097.1	4,482.4	597.5	8.9	1,039.1	11,225	6.5
Atlantic white-sided dolphin	117.6	103.4	45.1	0.7	78.4	345	0.4
Risso's dolphin	171.9	151.2	5.7	0.1	9.9	339	1.0
Short-finned pilot whale	238.8	210.1	0	0	0	449	1.6
Long-finned pilot whale	238.9	210.0	11.1	0.2	19.3	480	1.2
Harbor porpoise	124.0	109.1	102.1	1.5	177.6	514	0.5
Gray seal	439.7	386.7	60.6	0.9	105.4	993	0.2

TABLE 4—ESTIMATED TAKE NUMBERS AND TOTAL AUTHORIZED TAKE—Continued

Species	Estimated take— Central Atlantic		Estimated take— New York bight			Authorized take	Percent abundance
	Phase 1	Phase 2	Phase 1	Phase 2	Phase 3		
Harbor seal	237.5	208.9	136.2	2.0	236.9	822	1.3

¹ For rough-toothed dolphin, we authorize take in the form of one encounter with a group of average size, as assumed average group size (10) is larger than the total estimated take number (4). Mean group sizes were calculated from regional sightings data (Whitt *et al.*, 2015; Kraus *et al.*, 2016; Palka *et al.*, 2017).

² For common dolphin, estimated take numbers for the New York Bight survey area were calculated based on an assumption (based on monitoring data from the area) that 16 dolphins per day could be encountered within the harassment zone. These values were larger than and used instead of the results of density-based calculations.

Mitigation

In order to issue an IHA under section 101(a)(5)(D) of the MMPA, NMFS must set forth the permissible methods of taking pursuant to the activity, and other means of effecting the least practicable impact on the species or stock and its habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stock for taking for certain subsistence uses (latter not applicable for this action). NMFS regulations require applicants for incidental take authorizations to include information about the availability and feasibility (economic and technological) of equipment, methods, and manner of conducting the activity or other means of effecting the least practicable adverse impact upon the affected species or stocks, and their habitat (50 CFR 216.104(a)(11)).

In evaluating how mitigation may or may not be appropriate to ensure the least practicable adverse impact on species or stocks and their habitat, as well as subsistence uses where applicable, NMFS considers two primary factors:

(1) The manner in which, and the degree to which, the successful implementation of the measure(s) is expected to reduce impacts to marine mammals, marine mammal species or stocks, and their habitat, as well as subsistence uses. This considers the nature of the potential adverse impact being mitigated (likelihood, scope, range). It further considers the likelihood that the measure will be effective if implemented (probability of accomplishing the mitigating result if implemented as planned), the likelihood of effective implementation (probability implemented as planned); and

(2) The practicability of the measures for applicant implementation, which may consider such things as cost, and impact on operations.

NMFS requires that the following mitigation measures be implemented during TerraSond's planned marine site characterization surveys. Pursuant to section 7 of the ESA, TerraSond is also

required to adhere to relevant Project Design Criteria (PDC) of the NMFS' Greater Atlantic Regional Fisheries Office (GARFO) programmatic consultation (specifically PDCs 4, 5, and 7) regarding geophysical surveys along the U.S. Atlantic coast (www.fisheries.noaa.gov/new-england-mid-atlantic/consultations/section-7-take-reporting-programmatics-greater-atlantic#offshore-wind-site-assessment-and-site-characterization-activities-programmatic-consultation).

Visual Monitoring and Shutdown Zones

During survey operations (e.g., any day on which use of the sparker source is planned to occur, and whenever the sparker source is in the water, whether activated or not), a minimum of one visual PSO must be on duty on each source vessel and conducting visual observations at all times during daylight hours (*i.e.*, from 30 minutes prior to sunrise through 30 minutes following sunset). A minimum of two PSOs must be on duty on each source vessel during nighttime hours. Visual monitoring must begin no less than 30 minutes prior to ramp-up (described below) and must continue until one hour after use of the sparker source ceases.

Visual PSOs shall coordinate to ensure 360° visual coverage around the vessel from the most appropriate observation posts and shall conduct visual observations using binoculars and the naked eye while free from distractions and in a consistent, systematic, and diligent manner. PSOs shall establish and monitor applicable shutdown zones (see below). These zones shall be based upon the radial distance from the sparker source (rather than being based around the vessel itself).

Two shutdown zones are defined, depending on the species and context. Here, an extended shutdown zone encompassing the area at and below the sea surface out to a radius of 500 m from the sparker source (0–500 m) is defined for NARWs. For all other marine mammals, the shutdown zone encompasses a standard distance of 100 m (0–100 m). Any observations of

marine mammals by crew members aboard any vessel associated with the survey shall be relayed to the PSO team.

Visual PSOs may be on watch for a maximum of four consecutive hours followed by a break of at least one hour between watches and may conduct a maximum of 12 hours of observation per 24-hr period.

Pre-Start Clearance and Ramp-Up

A ramp-up procedure, involving a gradual increase in source level output, is required at all times as part of the activation of the sparker source when technically feasible. Operators should ramp up sparkers to half power for 5 minutes and then proceed to full power. A 30-minute pre-start clearance observation period must occur prior to the start of ramp-up. The intent of pre-start clearance observation (30 minutes) is to ensure no marine mammals are within the shutdown zones prior to the beginning of ramp-up. The intent of ramp-up is to warn marine mammals of pending operations and to allow sufficient time for those animals to leave the immediate vicinity. All operators must adhere to the following pre-start clearance and ramp-up requirements:

- The operator must notify a designated PSO of the planned start of ramp-up as agreed upon with the lead PSO; the notification time should not be less than 60 minutes prior to the planned ramp-up in order to allow the PSOs time to monitor the shutdown zones for 30 minutes prior to the initiation of ramp-up (pre-start clearance). During this 30 minute pre-start clearance period the entire shutdown zone must be visible, except as indicated below.

- Ramp-ups shall be scheduled so as to minimize the time spent with the source activated.

- A visual PSO conducting pre-start clearance observations must be notified again immediately prior to initiating ramp-up procedures and the operator must receive confirmation from the PSO to proceed.

- Any PSO on duty has the authority to delay the start of survey operations if a marine mammal is detected within the applicable pre-start clearance zone.

- The operator must establish and maintain clear lines of communication directly between PSOs on duty and crew controlling the acoustic source to ensure that mitigation commands are conveyed swiftly while allowing PSOs to maintain watch.

- The pre-start clearance requirement is waived for small delphinids and pinnipeds. Detection of a small delphinid (individual belonging to the following genera of the Family Delphinidae: *Steno*, *Delphinus*, *Lagenorhynchus*, *Stenella*, and *Tursiops*) or pinniped within the shutdown zone does not preclude beginning of ramp-up, unless the PSO confirms the individual to be of a genus other than those listed, in which case normal pre-clearance requirements apply.

- If there is uncertainty regarding identification of a marine mammal species (*i.e.*, whether the observed marine mammal(s) belongs to one of the delphinid genera for which the pre-clearance requirement is waived), PSOs may use best professional judgment in making the decision to call for a shutdown.

- Ramp-up may not be initiated if any marine mammal to which the pre-start clearance requirement applies is within the shutdown zone. If a marine mammal is observed within the shutdown zone during the 30 minute pre-start clearance period, ramp-up may not begin until the animal(s) has been observed exiting the zones or until an additional time period has elapsed with no further sightings (30 minutes for all baleen whale species and sperm whales and 15 minutes for all other species).

- PSOs must monitor the shutdown zones 30 minutes before and during ramp-up, and ramp-up must cease and the source must be shut down upon observation of a marine mammal within the applicable shutdown zone.

- Ramp-up may occur at times of poor visibility, including nighttime, if appropriate visual monitoring has occurred with no detections of marine mammals in the 30 minutes prior to beginning ramp-up. Sparker activation may only occur at night where operational planning cannot reasonably avoid such circumstances.

- If the acoustic source is shut down for brief periods (*i.e.*, less than 30 minutes) for reasons other than implementation of prescribed mitigation (*e.g.*, mechanical difficulty), it may be activated again without ramp-up if PSOs have maintained constant visual observation and no detections of marine mammals have occurred within the applicable shutdown zone. For any

longer shutdown, pre-start clearance observation and ramp-up are required.

Shutdown

All operators must adhere to the following shutdown requirements:

- Any PSO on duty has the authority to call for shutdown of the sparker source if a marine mammal is detected within the applicable shutdown zone.

- The operator must establish and maintain clear lines of communication directly between PSOs on duty and crew controlling the source to ensure that shutdown commands are conveyed swiftly while allowing PSOs to maintain watch.

- When the sparker source is active and a marine mammal appears within or enters the applicable shutdown zone, the source must be shut down. When shutdown is instructed by a PSO, the source must be immediately deactivated and any dispute resolved only following deactivation.

- The shutdown requirement is waived for small delphinids and pinnipeds. If a small delphinid (individual belonging to the following genera of the Family Delphinidae: *Steno*, *Delphinus*, *Lagenorhynchus*, *Stenella*, and *Tursiops*) or pinniped is visually detected within the shutdown zone, no shutdown is required unless the PSO confirms the individual to be of a genus other than those listed, in which case a shutdown is required.

- If there is uncertainty regarding identification of a marine mammal species (*i.e.*, whether the observed marine mammal(s) belongs to one of the delphinid genera for which shutdown is waived or one of the species with a larger shutdown zone), PSOs may use best professional judgment in making the decision to call for a shutdown.

- Upon implementation of shutdown, the source may be reactivated after the marine mammal has been observed exiting the applicable shutdown zone or following a clearance period (30 minutes for all baleen whale species and sperm whales and 15 minutes for all other species) with no further detection of the marine mammal.

If a species for which authorization has not been granted, or a species for which authorization has been granted but the authorized number of takes have been met, approaches or is observed within the Level B harassment zone, shutdown would occur.

Vessel Strike Avoidance

Crew and supply vessel personnel should use an appropriate reference guide that includes identifying information on all marine mammals that may be encountered. Vessel operators

must comply with the below measures except under extraordinary circumstances when the safety of the vessel or crew is in doubt or the safety of life at sea is in question. These requirements do not apply in any case where compliance would create an imminent and serious threat to a person or vessel or to the extent that a vessel is restricted in its ability to maneuver and, because of the restriction, cannot comply.

- Vessel operators and crews must maintain a vigilant watch for all marine mammals and slow down, stop their vessel, or alter course, as appropriate and regardless of vessel size, to avoid striking any marine mammal. A single marine mammal at the surface may indicate the presence of submerged animals in the vicinity of the vessel; therefore, precautionary measures should always be exercised. A visual observer aboard the vessel must monitor a vessel strike avoidance zone around the vessel (species-specific distances detailed below). Visual observers monitoring the vessel strike avoidance zone may be third-party observers (*i.e.*, PSOs) or crew members, but crew members responsible for these duties must be provided sufficient training to: (1) distinguish marine mammal from other phenomena and (2) broadly to identify a marine mammal as a right whale, other whale (defined in this context as sperm whales or baleen whales other than right whales), or other marine mammals.

- All vessels, regardless of size, must observe a 10-kn speed restriction in specific areas designated by NMFS for the protection of North Atlantic right whales from vessel strikes. These include all Seasonal Management Areas (SMA) (when in effect), any dynamic management areas (DMA) (when in effect), and Slow Zones. See www.fisheries.noaa.gov/national/ endangered-species-conservation/ reducing-ship-strikes-north-atlantic-right-whales for specific detail regarding these areas.

- Vessel speeds must also be reduced to 10 kn or less when mother/calf pairs, pods, or large assemblages of cetaceans are observed near a vessel.

- All vessels must maintain a minimum separation distance of 500 m from right whales. If a right whale is sighted within the relevant separation distance, the vessel must steer a course away at 10 kn or less until the 500-m separation distance has been established. If a whale is observed but cannot be confirmed as a species other than a right whale, the vessel operator must assume that it is a right whale and take appropriate action.

- All vessels must maintain a minimum separation distance of 100 m from sperm whales and all other baleen whales.
- All vessels must, to the maximum extent practicable, attempt to maintain a minimum separation distance of 50 m from all other marine mammals, with an understanding that at times this may not be possible (*e.g.*, for animals that approach the vessel).
- When marine mammals are sighted while a vessel is underway, the vessel shall take action as necessary to avoid violating the relevant separation distance (*e.g.*, attempt to remain parallel to the animal's course, avoid excessive speed or abrupt changes in direction until the animal has left the area, reduce speed and shift the engine to neutral). This does not apply to any vessel towing gear or any vessel that is navigationally constrained.

Members of the PSO team will consult NMFS' North Atlantic right whale reporting system and Whale Alert, daily and as able, for the presence of NARWs throughout survey operations, and for the establishment of DMAs and/or Slow Zones. It is TerraSond's responsibility to maintain awareness of the establishment and location of any such areas and to abide by these requirements accordingly.

Based on our evaluation of the required measures, as well as other measures considered by NMFS, NMFS has determined that the mitigation measures provide the means of effecting the least practicable impact on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance.

Monitoring and Reporting

In order to issue an IHA for an activity, section 101(a)(5)(D) of the MMPA states that NMFS must set forth requirements pertaining to the monitoring and reporting of such taking. The MMPA implementing regulations at 50 CFR 216.104(a)(13) indicate that requests for authorizations must include the suggested means of accomplishing the necessary monitoring and reporting that will result in increased knowledge of the species and of the level of taking or impacts on populations of marine mammals that are expected to be present while conducting the activities. Effective reporting is critical both to compliance as well as ensuring that the most value is obtained from the required monitoring.

Monitoring and reporting requirements prescribed by NMFS should contribute to improved

understanding of one or more of the following:

- Occurrence of marine mammal species or stocks in the area in which take is anticipated (*e.g.*, presence, abundance, distribution, density);
- Nature, scope, or context of likely marine mammal exposure to potential stressors/impacts (individual or cumulative, acute or chronic), through better understanding of: (1) action or environment (*e.g.*, source characterization, propagation, ambient noise); (2) affected species (*e.g.*, life history, dive patterns); (3) co-occurrence of marine mammal species with the activity; or (4) biological or behavioral context of exposure (*e.g.*, age, calving or feeding areas);
- Individual marine mammal responses (behavioral or physiological) to acoustic stressors (acute, chronic, or cumulative), other stressors, or cumulative impacts from multiple stressors;
- How anticipated responses to stressors impact either: (1) long-term fitness and survival of individual marine mammals; or (2) populations, species, or stocks;
- Effects on marine mammal habitat (*e.g.*, marine mammal prey species, acoustic habitat, or other important physical components of marine mammal habitat); and,
- Mitigation and monitoring effectiveness.

TerraSond must use independent, dedicated, trained PSOs, meaning that the PSOs must be employed by a third-party observer provider, must have no tasks other than to conduct observational effort, collect data, and communicate with and instruct relevant vessel crew with regard to the presence of marine mammal and mitigation requirements (including brief alerts regarding maritime hazards), and must have successfully completed an approved PSO training course for geophysical surveys. Visual monitoring must be performed by qualified, NMFS-approved PSOs. PSO resumes must be provided to NMFS for review and approval prior to the start of survey activities.

PSO names must be provided to NMFS by the operator for review and confirmation of their approval for specific roles prior to commencement of the survey. For prospective PSOs not previously approved, or for PSOs whose approval is not current, NMFS must review and approve PSO qualifications. Resumes should include information related to relevant education, experience, and training, including dates, duration, location, and description of prior PSO experience.

Resumes must be accompanied by relevant documentation of successful completion of necessary training.

NMFS may approve PSOs as conditional or unconditional. A conditionally-approved PSO may be one who is trained but has not yet attained the requisite experience. An unconditionally-approved PSO is one who has attained the necessary experience. For unconditional approval, the PSO must have a minimum of 90 days at sea performing the role during a geophysical survey, with the conclusion of the most recent relevant experience not more than 18 months previous.

At least one of the visual PSOs aboard the vessel must be unconditionally-approved. One unconditionally-approved visual PSO shall be designated as the lead for the entire PSO team. This lead should typically be the PSO with the most experience, who would coordinate duty schedules and roles for the PSO team and serve as primary point of contact for the vessel operator. To the maximum extent practicable, the duty schedule shall be planned such that unconditionally-approved PSOs are on duty with conditionally-approved PSOs.

PSOs must successfully complete relevant training, including completion of all required coursework and passing (80 percent or greater) a written and/or oral examination developed for the training program.

PSOs must have successfully attained a bachelor's degree from an accredited college or university with a major in one of the natural sciences, a minimum of 30 semester hours or equivalent in the biological sciences, and at least one undergraduate course in math or statistics. The educational requirements may be waived if the PSO has acquired the relevant skills through alternate experience. Requests for such a waiver shall be submitted to NMFS and must include written justification. Alternate experience that may be considered includes, but is not limited to (1) secondary education and/or experience comparable to PSO duties; (2) previous work experience conducting academic, commercial, or government-sponsored marine mammal surveys; and (3) previous work experience as a PSO (PSO must be in good standing and demonstrate good performance of PSO duties).

TerraSond must work with the selected third-party PSO provider to ensure PSOs have all equipment (including backup equipment) needed to adequately perform necessary tasks, including accurate determination of distance and bearing to observed marine

mammals, and to ensure that PSOs are capable of calibrating equipment as necessary for accurate distance estimates and species identification. Such equipment, at a minimum, shall include:

- At least one thermal (infrared) image device suited for the marine environment;
- Reticule binoculars (*e.g.*, 7 x 50) of appropriate quality (at least one per PSO, plus backups);
- Global Positioning Units (GPS) (at least one plus backups);
- Digital cameras with a telephoto lens that is at least 300-mm or equivalent on a full-frame single lens reflex (SLR) (at least one plus backups). The camera or lens should also have an image stabilization system;
- Equipment necessary for accurate measurement of distances to marine mammal;
- Compasses (at least one plus backups);
- Means of communication among vessel crew and PSOs; and
- Any other tools deemed necessary to adequately and effectively perform PSO tasks.

The equipment specified above may be provided by an individual PSO, the third-party PSO provider, or the operator, but TerraSond is responsible for ensuring PSOs have the proper equipment required to perform the duties specified in the IHA.

The PSOs will be responsible for monitoring the waters surrounding the survey vessel to the farthest extent permitted by sighting conditions, including shutdown zones, during all HRG survey operations. PSOs will visually monitor and identify marine mammals, including those approaching or entering the established shutdown zones during survey activities. It will be the responsibility of the PSO(s) on duty to communicate the presence of marine mammals as well as to communicate the action(s) that are necessary to ensure mitigation and monitoring requirements are implemented as appropriate.

PSOs must be equipped with binoculars and have the ability to estimate distance and bearing to detect marine mammals, particularly in proximity to shutdown zones. Reticulated binoculars must also be available to PSOs for use as appropriate based on conditions and visibility to support the sighting and monitoring of marine mammals. During nighttime operations, night-vision goggles with thermal clip-ons and infrared technology must be available for use. Position data would be recorded using hand-held or vessel GPS units for each sighting.

During good conditions (*e.g.*, daylight hours; Beaufort sea state (BSS) 3 or less), to the maximum extent practicable, PSOs should also conduct observations when the acoustic source is not operating for comparison of sighting rates and behavior with and without use of the active acoustic sources. Any observations of marine mammals by crew members aboard the vessel associated with the survey would be relayed to the PSO team.

Data on all PSO observations would be recorded based on standard PSO collection requirements (see *Reporting Measures*). This would include dates, times, and locations of survey operations; dates and times of observations, location and weather; details of marine mammal sightings (*e.g.*, species, numbers, behavior); and details of any observed marine mammal behavior that occurs (*e.g.*, noted behavioral disturbances).

Reporting Measures

TerraSond shall submit a draft summary report on all activities and monitoring results within 90 days of the completion of the survey or expiration of the IHA, whichever comes sooner. The report must describe all activities conducted and sightings of marine mammals, must provide full documentation of methods, results, and interpretation pertaining to all monitoring, and must summarize the dates and locations of survey operations and all marine mammals sightings (dates, times, locations, activities, associated survey activities). The draft report shall also include geo-referenced, time-stamped vessel tracklines for all time periods during which acoustic sources were operating. Tracklines should include points recording any change in acoustic source status (*e.g.*, when the sources began operating, when they were turned off, or when they changed operational status such as from full array to single gun or vice versa). GIS files shall be provided in ESRI shapefile format and include the UTC date and time, latitude in decimal degrees, and longitude in decimal degrees. All coordinates shall be referenced to the WGS84 geographic coordinate system. In addition to the report, all raw observational data shall be made available. The report must summarize the information. A final report must be submitted within 30 days following resolution of any comments on the draft report. All draft and final marine mammal monitoring reports must be submitted to PR.ITP.MonitoringReports@noaa.gov and nmfs.gar.incidental-take@noaa.gov.

PSOs must use standardized electronic data forms to record data. PSOs shall record detailed information about any implementation of mitigation requirements, including the distance of marine mammal to the acoustic source and description of specific actions that ensued, the behavior of the animal(s), any observed changes in behavior before and after implementation of mitigation, and if shutdown was implemented, the length of time before any subsequent ramp-up of the acoustic source. If required mitigation was not implemented, PSOs should record a description of the circumstances. At a minimum, the following information must be recorded:

1. Vessel name (source vessel), vessel size and type, maximum speed capability of vessel;
2. Dates of departures and returns to port with port name;
3. PSO names and affiliations;
4. Date and participants of PSO briefings;
5. Visual monitoring equipment used;
6. PSO location on vessel and height of observation location above water surface;
7. Dates and times (Greenwich Mean Time) of survey on/off effort and times corresponding with PSO on/off effort;
8. Vessel location (decimal degrees) when survey effort begins and ends and vessel location at beginning and end of visual PSO duty shifts;
9. Vessel location at 30-second intervals if obtainable from data collection software, otherwise at practical regular interval
10. Vessel heading and speed at beginning and end of visual PSO duty shifts and upon any change;
11. Water depth (if obtainable from data collection software);
12. Environmental conditions while on visual survey (at beginning and end of PSO shift and whenever conditions change significantly), including BSS and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon;
13. Factors that may contribute to impaired observations during each PSO shift change or as needed as environmental conditions change (*e.g.*, vessel traffic, equipment malfunctions); and
14. Survey activity information (and changes thereof), such as acoustic source power output while in operation, number and volume of airguns operating in an array, tow depth of an acoustic source, and any other notes of significance (*i.e.*, pre-start clearance, ramp-up, shutdown, testing, shooting,

ramp-up completion, end of operations, streamers, etc.).

15. Upon visual observation of any marine mammal, the following information must be recorded:

- a. Watch status (sighting made by PSO on/off effort, opportunistic, crew, alternate vessel/platform);
- b. Vessel/survey activity at time of sighting (*e.g.*, deploying, recovering, testing, shooting, data acquisition, other);
- c. PSO who sighted the animal;
- d. Time of sighting;
- e. Initial detection method;
- f. Sightings cue;
- g. Vessel location at time of sighting (decimal degrees);
- h. Direction of vessel's travel (compass direction);
- i. Speed of the vessel(s) from which the observation was made;
- j. Identification of the animal (*e.g.*, genus/species, lowest possible taxonomic level or unidentified); also note the composition of the group if there is a mix of species;
- k. Species reliability (an indicator of confidence in identification);
- l. Estimated distance to the animal and method of estimating distance;
- m. Estimated number of animals (high/low/best);
- n. Estimated number of animals by cohort (adults, yearlings, juveniles, calves, group composition, etc.);
- o. Description (as many distinguishing features as possible of each individual seen, including length, shape, color, pattern, scars, or markings, shape and size of dorsal fin, shape of head, and blow characteristics);
- p. Detailed behavior observations (*e.g.*, number of blows/breaths, number of surfaces, breaching, spyhopping, diving, feeding, traveling; as explicit and detailed as possible; note any observed changes in behavior before and after point of closest approach);
- q. Mitigation actions; description of any actions implemented in response to the sighting (*e.g.*, delays, shutdowns, ramp-up, speed or course alteration, etc.) and time and location of the action;
- r. Equipment operating during sighting;
- s. Animal's closest point of approach and/or closest distance from the center point of the acoustic source; and
- t. Description of any actions implemented in response to the sighting (*e.g.*, delays, shutdown, ramp-up) and time and location of the action.

If a NARW is observed at any time by PSOs or personnel on the project vessel, during surveys or during vessel transit, TerraSond must report the sighting information to the NMFS North Atlantic Right Whale Sighting Advisory System

(866-755-6622) within 2 hours of occurrence, when practicable, or no later than 24 hours after occurrence. North Atlantic right whale sightings in any location may also be reported to the U.S. Coast Guard via channel 16 and through the WhaleAlert app (www.whalealert.org).

In the event that personnel involved in the survey activities discover an injured or dead marine mammal, the incident must be reported to NMFS as soon as feasible by phone (866-755-6622) and by email (nmfs.gar.incidental-take@noaa.gov and PR.ITP.MonitoringReports@noaa.gov). The report must include the following information:

1. Time, date, and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
2. Species identification (if known) or description of the animal(s) involved;
3. Condition of the animal(s) (including carcass condition if the animal is dead);
4. Observed behaviors of the animal(s), if alive;
5. If available, photographs or video footage of the animal(s); and
6. General circumstances under which the animal was discovered.

In the event of a ship strike of a marine mammal by any vessel involved in the activities, TerraSond must report the incident to NMFS by phone (866-755-6622) and by email (nmfs.gar.incidental-take@noaa.gov and PR.ITP.MonitoringReports@noaa.gov) as soon as feasible. The report must include the following information:

1. Time, date, and location (latitude/longitude) of the incident;
2. Species identification (if known) or description of the animal(s) involved;
3. Vessel's speed during and leading up to the incident;
4. Vessel's course/heading and what operations were being conducted (if applicable);
5. Status of all sound sources in use;
6. Description of avoidance measures/requirements that were in place at the time of the strike and what additional measures were taken, if any, to avoid strike;
7. Environmental conditions (*e.g.*, wind speed and direction, BSS, cloud cover, visibility) immediately preceding the strike;
8. Estimated size and length of animal that was struck;
9. Description of the behavior of the marine mammal immediately preceding and/or following the strike;
10. If available, description of the presence and behavior of any other marine mammals immediately preceding the strike;

11. Estimated fate of the animal (*e.g.*, dead, injured but alive, injured and moving, blood or tissue observed in the water, status unknown, disappeared); and

12. To the extent practicable, photographs or video footage of the animal(s).

Negligible Impact Analysis and Determination

NMFS has defined negligible impact as an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival (50 CFR 216.103). A negligible impact finding is based on the lack of likely adverse effects on annual rates of recruitment or survival (*i.e.*, population-level effects). An estimate of the number of takes alone is not enough information on which to base an impact determination. In addition to considering estimates of the number of marine mammals that might be "taken" through harassment, NMFS considers other factors, such as the likely nature of any impacts or responses (*e.g.*, intensity, duration), the context of any impacts or responses (*e.g.*, critical reproductive time or location, foraging impacts affecting energetics), as well as effects on habitat, and the likely effectiveness of the mitigation. We also assess the number, intensity, and context of estimated takes by evaluating this information relative to population status. Consistent with the 1989 preamble for NMFS' implementing regulations (54 FR 40338, September 29, 1989), the impacts from other past and ongoing anthropogenic activities are incorporated into this analysis via their impacts on the baseline (*e.g.*, as reflected in the regulatory status of the species, population size and growth rate where known, ongoing sources of human-caused mortality, or ambient noise levels).

To avoid repetition, the majority of our analysis applies to all the species listed in Table 2, given that the anticipated effects of this project on different marine mammal stocks are expected to be relatively similar in nature. Where there are meaningful differences between species or stocks, or groups of species, in anticipated individual responses to activities, impact of expected take on the population due to differences in population status, or impacts on habitat, they are included as a separate subsections. Specifically, we provide additional discussion related to NARWs and to other species currently

experiencing unusual mortality events (UME).

NMFS does not anticipate that serious injury or mortality would occur as a result of HRG surveys, even in the absence of mitigation, and no serious injury or mortality is authorized. As discussed in the Potential Effects of Specified Activities on Marine Mammals and their Habitat section of the proposed **Federal Register** notice (87 FR 66658, November 4, 2022), non-auditory physical effects and vessel strike are not expected to occur. NMFS expects that all potential takes would be in the form of short-term Level B behavioral harassment, *e.g.*, temporary avoidance of the area or decreased foraging (if such activity was occurring), reactions that are considered to be of low severity and with no lasting biological consequences (*e.g.*, Southall *et al.*, 2007, Ellison *et al.*, 2012). As described above, Level A harassment is not expected to occur given the nature of the operations, the estimated size of the Level A harassment zones, and the required shutdown zones for certain activities.

In addition to being temporary, the maximum expected harassment zone around a survey vessel is 141 m. Therefore, the ensonified area surrounding each vessel is relatively small compared to the overall distribution of the animals in the area and their use of the habitat. Feeding behavior is not likely to be significantly impacted as prey species are mobile and are broadly distributed throughout the survey area; therefore, marine mammals that may be temporarily displaced during survey activities are expected to be able to resume foraging once they have moved away from areas with disturbing levels of underwater noise. Because of the temporary nature of the disturbance and the availability of similar habitat and resources in the surrounding area, the impacts to marine mammals and the food sources that they utilize are not expected to cause significant or long-term consequences for individual marine mammals or their populations.

There are no rookeries, mating or calving grounds known to be biologically important to marine mammals within the survey area and there are no feeding areas known to be biologically important to marine mammals within the survey area. There is no designated critical habitat for any ESA-listed marine mammals in the survey area.

North Atlantic Right Whales

The status of the NARW population is of heightened concern and, therefore,

merits additional analysis. As noted previously, elevated NARW mortalities began in 2017 and there is an active UME. Overall, preliminary findings support human interactions, specifically vessel strikes and entanglements, as the cause of death for the majority of right whales. The survey area overlaps a migratory corridor BIA for NARWs that extends from Massachusetts to Florida and from the coast to beyond the shelf break. Due to the fact that the survey activities are temporary and the spatial extent of sound produced by the survey would be small relative to the spatial extent of the available migratory habitat in the BIA, right whale migration is not expected to be impacted by the planned survey. Given the relatively small size of the ensonified area, it is unlikely that prey availability would be adversely affected by HRG survey operations. Required vessel strike avoidance measures will also decrease risk of ship strike during migration; no ship strike is expected to occur during TerraSond's activities. Additionally, only very limited take by Level B harassment of NARWs has been requested and is being authorized by NMFS as HRG survey operations are required to maintain and implement a 500 m shutdown zone. The 500 m shutdown zone for right whales is conservative, considering the Level B harassment isopleth for the acoustic source (*i.e.*, sparker) is estimated to be 141 m, and thereby minimizes the potential for behavioral harassment of this species. As noted previously, Level A harassment is not expected due to the small estimated zones in conjunction with the aforementioned shutdown requirements. NMFS does not anticipate North Atlantic right whales takes that would result from TerraSond's activities would impact annual rates of recruitment or survival. Thus, any takes that occur would not result in population level impacts.

Other Marine Mammal Species With Active UMEs

As noted previously, there are several active UMEs occurring in the vicinity of TerraSond's survey areas. Elevated humpback whale mortalities have occurred along the Atlantic coast from Maine through Florida since 2016. Of the cases examined, approximately half had evidence of human interaction (ship strike or entanglement). The UME does not yet provide cause for concern regarding population-level impacts. Despite the UME, the relevant population of humpback whales (the West Indies breeding population, or DPS) remains stable at approximately 12,000 individuals.

Beginning in 2017, elevated minke whale strandings have occurred along the Atlantic coast from Maine through South Carolina, with highest numbers in Massachusetts, Maine, and New York. This event does not provide cause for concern regarding population level impacts, as the likely population abundance is greater than 20,000 whales.

Elevated numbers of harbor seal and gray seal mortalities were first observed between 2018–2020 and, as part of a separate UME, again in 2022. These have occurred across Maine, New Hampshire, and Massachusetts. Based on tests conducted so far, the main pathogen found in the seals is phocine distemper virus (2018–2020) and avian influenza (2022), although additional testing to identify other factors that may be involved in the UMEs is underway. The UMEs do not provide cause for concern regarding population-level impacts to any of these stocks. For harbor seals, the population abundance is over 60,000 and annual M/SI (339) is well below PBR (1,729) (Hayes *et al.*, 2021). The population abundance for gray seals in the United States is over 27,000, with an estimated abundance, including seals in Canada, of approximately 450,000. In addition, the abundance of gray seals is likely increasing in the U.S. Atlantic as well as in Canada (Hayes *et al.*, 2021).

The required mitigation measures are expected to reduce the number and/or severity of takes for all species listed in Table 2, including those with active UMEs, to the level of least practicable adverse impact. In particular, they would provide animals the opportunity to move away from the sound source before HRG survey equipment reaches full energy, thus preventing them from being exposed to more severe Level B harassment. No Level A harassment is anticipated, even in the absence of mitigation measures, or authorized.

NMFS expects that takes would be in the form of short-term Level B behavioral harassment by way of brief startling reactions and/or temporary vacating of the area, or decreased foraging (if such activity was occurring)—reactions that (at the scale and intensity anticipated here) are considered to be of low severity, with no lasting biological consequences. Since both the sources and marine mammals are mobile, animals would only be exposed briefly to a small ensonified area that might result in take. Required mitigation measures, such as shutdown zones and ramp up, would further reduce exposure to sound that could result in more severe behavioral harassment.

In summary and as described above, the following factors primarily support our determination that the impacts resulting from this activity are not expected to adversely affect the species or stock through effects on annual rates of recruitment or survival:

- No mortality or serious injury is anticipated or authorized;
- No Level A harassment (PTS) is anticipated, even in the absence of mitigation measures, or authorized;
- Foraging success is not likely to be significantly impacted as effects on species that serve as prey species for marine mammals from the survey are expected to be minimal;
- The availability of alternate areas of similar habitat value for marine mammals to temporarily vacate the ensonified areas during the planned survey to avoid exposure to sounds from the activity;
- Take is anticipated to be primarily Level B behavioral harassment consisting of brief startle reactions and/or temporary avoidance of the ensonified area;
- While the survey area is within areas noted as a migratory BIA for NARWs, avoidance of the survey area due to the activities is not anticipated and would not likely affect migration. In addition, mitigation measures require shutdown at 500 m (almost four times the size of the Level B harassment isopleth of 141 m) to minimize the effects of any Level B harassment take of the species; and
- The required mitigation measures, including visual monitoring and shutdowns, are expected to minimize potential impacts to other marine mammals.

Based on the analysis contained herein of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the required monitoring and mitigation measures, NMFS finds that the total marine mammal take from the activity will have a negligible impact on all affected marine mammal species or stocks.

Small Numbers

As noted previously, only small numbers of incidental take may be authorized under sections 101(a)(5)(A) and (D) of the MMPA for specified activities other than military readiness activities. The MMPA does not define small numbers and so, in practice, where estimated numbers are available, NMFS compares the number of individuals taken to the most appropriate estimation of abundance of the relevant species or stock in our

determination of whether an authorization is limited to small numbers of marine mammals. When the predicted number of individuals to be taken is fewer than one-third of the species or stock abundance, the take is considered to be of small numbers. Additionally, other qualitative factors may be considered in the analysis, such as the temporal or spatial scale of the activities.

The amount of take NMFS proposes to authorize is below one-third of the estimated stock abundance for all species (total take is less than 7.5 percent of the abundance of the affected stocks for all species, see Table 4). The figures presented in Table 4 are considered conservative estimates for purposes of the small numbers determination as they assume all takes represent different individual animals, which is unlikely to be the case.

Based on the analysis contained herein of the activity (including the mitigation and monitoring measures) and the anticipated take of marine mammals, NMFS finds that small numbers of marine mammals would be taken relative to the population size of the affected species or stocks.

Unmitigable Adverse Impact Analysis and Determination

There are no relevant subsistence uses of the affected marine mammal stocks or species implicated by this action. Therefore, NMFS has determined that the total taking of affected species or stocks would not have an unmitigable adverse impact on the availability of such species or stocks for taking for subsistence purposes.

Endangered Species Act

Section 7(a)(2) of the Endangered Species Act of 1973 (ESA; 16 U.S.C. 1531 *et seq.*) requires that each Federal agency insure that any action it authorizes, funds, or carries out 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. To ensure ESA compliance for the issuance of IHAs, NMFS consults internally whenever we propose to authorize take for endangered or threatened species.

NMFS has authorized the incidental take of four species of marine mammals which are listed under the ESA, including the North Atlantic right, fin, sei, and sperm whale, and has determined that these activities fall within the scope of activities analyzed in GARFO's programmatic consultation regarding geophysical surveys along the U.S. Atlantic coast in the three Atlantic

Renewable Energy Regions (completed June 29, 2021; revised September 2021).

Authorization

As a result of these determinations, NMFS has issued an IHA to TerraSond for conducting marine site characterization surveys in the New York Bight and Central Atlantic for a period of 1 year, provided the previously mentioned mitigation, monitoring, and reporting requirements are incorporated. The IHA can be found at: <https://www.fisheries.noaa.gov/action/incidental-take-authorization-terrasond-limited-marine-site-characterization-surveys-new>.

Dated: May 15, 2023.

Kimberly Damon-Randall,

*Director, Office of Protected Resources,
National Marine Fisheries Service.*

[FR Doc. 2023–10639 Filed 5–17–23; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XD003]

Marine Mammals and Endangered Species

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of permits and permit amendments.

SUMMARY: Notice is hereby given that permits and permit amendments have been issued to the following entities under the Marine Mammal Protection Act (MMPA) and the Endangered Species Act (ESA), as applicable.

ADDRESSES: The permits and related documents are available for review upon written request via email to NMFS.Pr1Comments@noaa.gov.

FOR FURTHER INFORMATION CONTACT: Erin Markin, Ph.D., (Permit Nos. 25686 and 27027), Shasta McClenahan, Ph.D., (Permit No. 26919), Carrie Hubard (Permit No. 27077), Jennifer Skidmore (Permit Nos. 27225 and 27267), Courtney Smith, Ph.D. (Permit Nos. 24378–01, 27099), and Sara Young (Permit No. 27272); at (301) 427–8401.

SUPPLEMENTARY INFORMATION: Notices were published in the **Federal Register** on the dates listed below that requests for a permit or permit amendment had been submitted by the below-named applicants. To locate the **Federal Register** notice that announced our receipt of the application and a

complete description of the activities, go to <https://www.federalregister.gov> and search on the permit number provided in Table 1 below.

TABLE 1—ISSUED PERMITS

Permit No.	RTID	Applicant	Previous Federal Register notice	Issuance date
24378–01	0648–XC630	The University of Alaska Southeast, 1332 Seward Ave, Sitka, AK 99835 (Responsible Party: Jan Straley).	87 FR 80527, December 30, 2022.	April 28, 2023.
25686	0648–XB542	NMFS Southeast Fisheries Science Center, 75 Virginia Beach, Miami, FL (Responsible Party: Lisa Desfosse, Ph.D.).	86 FR 59997, October 29, 2021	April 5, 2023.
26919	0648–XC724	Georgia Department of Natural Resources, 2070 U.S. Highway 278 Southeast, Social Circle, GA 30025 (Responsible Party: Matt Elliott).	88 FR 7080, February 2, 2023 ...	April 14, 2023.
27027	0648–XC718	Glacier Bay National Park and Preserve, P.O. Box 140, Gustavus, AK 99826 (Responsible Party: Thomas Schaff).	88 FR 4975, January 26, 2023 ...	April 28, 2023.
27077	0648–XC750	WSP Wild Water Productions Limited, St Stephen's Avenue, Bristol, BS1 1YL, United Kingdom (Responsible Party: Joanna Barwick).	88 FR 8408, February 9, 2023 ...	April 11, 2023.
27099	0648–XC782	Pacific Whale Foundation (Responsible Party: Jens Curie), 300 Ma'alaea Rd. Ste. 211, Wailuku, Hawaii 96793.	88 FR 10294, February 17, 2023	April 28, 2023.
27225	0648–XC783	Sea Research Foundation, Inc. dba Mystic Aquarium, 55 Coogan Boulevard, Mystic, CT 06355 (Responsible Party: Katie Cubina).	88 FR 10299, February 17, 2023	April 20, 2023.
27267	0648–XC816	The Maryland Zoo in Baltimore, 1876 Mansion House Drive, Baltimore, MD 21217 (Responsible Party: Ellen Bronson, DVM).	88 FR 15681, March 14, 2023	April 28, 2023.
27272	0648–XC768	Stellwagen Bank National Marine Sanctuary, 175 Edward Foster Road, Scituate, MA 02066 (Responsible Party: David Wiley, Ph.D.).	88 FR 9870, February 15, 2023	April 20, 2023.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), a final determination has been made that the activities proposed are categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

As required by the ESA, as applicable, issuance of these permit was based on a finding that such permits: (1) were applied for in good faith; (2) will not operate to the disadvantage of such endangered species; and (3) are consistent with the purposes and policies set forth in Section 2 of the ESA.

Authority: The requested permits have been issued under the MMPA 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 ESA 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), as applicable.

Dated: May 12, 2023.

Julia M. Harrison,
Chief, Permits and Conservation Division,
Office of Protected Resources, National
Marine Fisheries Service.

[FR Doc. 2023–10561 Filed 5–17–23; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF DEFENSE

Department of the Army, Corps of Engineers

Notice of Intent To Prepare a Draft Environmental Impact Statement for the Pearl River Flood Risk Management Project, Pearl River Watershed, Rankin and Hinds Counties, Mississippi

AGENCY: U.S. Army Corps of Engineers, Department of the Army, DoD.

ACTION: Notice of intent to prepare a draft environmental impact statement for the Pearl River Flood Risk Management Project, Pearl River Watershed, Rankin and Hinds Counties, Mississippi.

SUMMARY: The U.S. Army Corps of Engineers (USACE) intends to prepare a draft environmental impact statement (DEIS) for the Pearl River Flood Risk Management Project in Rankin and Hinds Counties, Mississippi to analyze flood risk management plans that can be implemented under section 3104 of the Water Resources Development Act (WRDA) of 2007. This notice updates the original Notice of Intent declaring the Rankin-Hinds Pearl River Flood and Drainage Control District, the non-Federal interest (NFI) and USACE's intent to conduct a Feasibility Study

and EIS process, which was published in the **Federal Register** on July 25, 2013. USACE is now preparing a DEIS to identify the national economic development (NED) plan by comparing the level of flood protection provided by the alternatives presented in the NFI's section 211 Study (Alternatives A and C) and two new USACE alternatives (Alternative A1 and Combination/Hybrid Plan, as allowed for by section 3104); assess the environmental acceptability and technical feasibility of the alternatives; and provide the Secretary the necessary information to choose a plan to implement. Additionally, consistent with section 1176 of WRDA 2018, the DEIS will assess potential downstream impacts to the Pearl River Basin.

DATES: All comments and suggestions must be submitted by June 20, 2023.

ADDRESSES: To ensure the Corps has sufficient time to consider public input in the preparation of the Draft EIS, scoping comments should be submitted by email at PearlRiverFRM@usace.army.mil, by surface mail to U.S. Army Corps of Engineers, CEMVK–PMP, 4155 Clay Street, Vicksburg, Mississippi 39183–3435, or at the Scoping Meeting(s).

FOR FURTHER INFORMATION CONTACT:

Questions and comments regarding the proposed project should reference “the

Pearl River Flood Risk Management Project” and be directed to Eric Williams at eric.m.williams@usace.army.mil or (504) 862–2862.

SUPPLEMENTARY INFORMATION:

Background: Section 3104 of WRDA 2007 modified the “Pearl River Basin Project” originally authorized by section 401(e)(3) of WRDA 1986 to authorize the Secretary to “construct the project generally in accordance with the plan described in the ‘Pearl River Watershed, Mississippi, Feasibility Study Main Report, Preliminary Draft’, dated February 2007” subject to subsection (c). Section 3104(c) provides that “[i]f the Secretary determines under subsection (b) that the locally preferred plan provides a level of flood damage reduction that is equal to or greater than the level of flood damage reduction provided by the national economic development plan and that the locally preferred plan is environmentally acceptable and technically feasible, the Secretary may construct the project identified as the national economic development plan, or the locally preferred plan, or some combination thereof.”

The NFI prepared a draft feasibility study/environmental impact statement (Study) under section 211 of the Water Resources Development Act (WRDA) of 1996 and submitted it to the Office of the Assistant Secretary of the Army for Civil Works (OASACW) in July 2022 for review. Since then, OASACW and USACE have been working with the NFI on resolving identified issues with the NFI section 211 Study.

For the past 100 years, headwater flooding of the Pearl River has caused disruption to citizens and businesses throughout the Jackson, Mississippi, metropolitan area, putting over 5,000 commercial and residential structures at risk of flood damage. Five of the highest river stages on record have occurred in the past 20 years. The greatest flood risk is borne by minority and low-income communities. Jackson has struggled with population loss and lost economic opportunity.

In 1996, local interests proposed the LeFleur Lakes Flood Control Plan, consisting of upper and lower lakes along the Pearl River south of the Ross Barnett Reservoir as an alternative to the comprehensive levee plan consisting of new levees, levee enlargements, water control structures, and culverts. USACE later prepared a preliminary feasibility study and draft environmental impact statement (FS/DEIS) evaluating the local interest plan and the comprehensive levee plan, dated February 2007, which was not noticed in the **Federal Register**,

but is referenced in the current DEIS. The levee plan was determined to be non-implementable.

In March of 2012, the NFI prepared a Preliminary Hydraulic and Hydrologic Report for a channel improvement concept along with some initial inquiries of a locally preferred plan with a smaller footprint. The flood risk management effort was continued in 2013 when the NFI team began rescoping the project with input from USACE, input from additional agencies and the public, and a review of previous alternatives. To efficiently and effectively consider as many measures as possible, the previous reports were utilized where possible, reevaluating the flood risk management measures studied and considering over 60 plans previously studied. During the review of plans examined in prior reports, plans were updated in some cases with current cost estimates; in other cases, plans were updated with continued modeling for updated and thorough analysis. Using this information, the USACE is conducting a reanalysis of engineering, economic, and environmental factors relative to prospective flood alleviation measures in the Pearl River Watershed study area (Metropolitan Jackson area) for Alternatives A, A1, C, and a Combination/Hybrid Plan by employing Department of the Army criteria and guidelines. The DEIS will examine the reasonably foreseeable environmental impacts of all reasonable alternatives that may be proposed.

Proposed Action: The purpose of the proposed action is to reduce flood risk in the Jackson metropolitan area; reduce the flood risk of critical infrastructure, including the Savanna Street Wastewater Treatment Facility; and to improve access to transportation routes, evacuation routes, and critical care facilities during flood events. For the past 100 years, headwater flooding of the Pearl River (greater than 10 feet deep in some areas) has caused disruption to businesses and industry throughout the Jackson, MS, metropolitan area. This area of increased flood risk includes 5,000 commercial and residential structures and effects a population of over 500,000. There have been numerous flood events that have affected the Study Area, most notably the Easter Flood of 1979 and the May Flood of 1983. Most recently, the Pearl River crested at 36.67 feet in Jackson on February 17, 2020, the third highest crest ever recorded.

Alternatives: Alternatives being considered include the following. Alternative A consists of relocating structures (buy out) and buying the land

upon which the structures were located. The total number of structures to be relocated in this alternative is more than 3,000, including residential structures, commercial structures, government and public buildings, schools, and hospitals. Alternative A1 will be for both residential and nonresidential structures receiving residual damages in the base year with the project in place. Nonstructural measures of acquisition, elevation, and floodproofing may be applied to several with-project floodplains and will be optimized by reach to the annual exceedance probability (AEP) event floodplain providing the highest net benefits. Alternative C consists of the construction of channel improvements, demolition of the existing weir near the J. H. Fewell Water Treatment Plant (WTP) site and construction of a new weir with a low-flow gate structure further downstream to enlarge the existing river channel, Federal levee improvements (excavated material plan), and upgrading an existing non-Federal levee into a federalized ring levee around the Savannah Street WWTP. The NFI's preferred alternative is a Channel Improvements Plan, Alternative C. Consideration of an alternative that is a combination, or hybrid, of these plans is authorized. The Combination/Hybrid Plan may consist of features that demonstrate effectiveness and efficiency in Alternatives A, A1, and C. Through this Notice, the public is invited to identify potential alternatives, information, and analyses relevant to the proposed action.

Summary of Expected Effects: It is anticipated that Alternatives A and A1 would have minimal impacts on natural resources but could have significant effects to the human environment. These alternatives propose the buyout of up to approximately 3,100 structures, including homes and businesses. Implementation of Alternative A or A1 would impact population and housing, employment and business activity, tax revenues, community cohesiveness and growth.

Alternative C's environmental effects will be further determined during the upcoming analyses. Based on the information available now approximately 2,069 acres of terrestrial habitat would be converted to aquatic habitat. Approximately 1,861 acres of wetlands and “other waters of the U.S.” and approximately 487 acres of existing surface water bodies, including the Pearl River channel and its tributaries, would be impacted. Additionally, impacts on threatened and endangered species by converting the portion of the

Pearl River within the project area from a riverine system to a lake system will be further reviewed. Water quality and quantity impacts downstream of the project area will also be reviewed pursuant to Section 1176.

Environmental Reviews and Consultation Requirements: The alternatives are being coordinated with federal, state, regional, and local agencies. In accordance with relevant environmental laws and regulations, USACE will engage at least the following agencies, some of which may also serve as cooperating or participating agencies in the EIS preparation: U. S. Fish and Wildlife Service (USFWS) under the Fish and Wildlife Coordination Act; USFWS under the Endangered Species Act; U.S. Environmental Protection Agency and the Mississippi Department of Environment Quality under the Clean Air Act and the Clean Water Act; Mississippi Department of Wildlife Fisheries and Parks, Mississippi Department of Marine Resources, Mississippi Department of Archives and History, Louisiana Department of Environmental Quality, Louisiana Department of Natural Resources, Louisiana Department of Wildlife and Fisheries, Louisiana Coastal Protection and Restoration Authority, and the Advisory Council on Historic Preservation and Federally-recognized Indian Tribes under the National Historic Preservation Act.

NEPA Schedule: The draft EIS is presently scheduled to be available for public review and comment in September 2023. A 45-day public review period will be provided for interested parties and agencies to review and comment on this draft document. All interested parties are encouraged to respond to this notice and provide a current address if they wish to be notified of the Draft EIS circulation. A Record of Decision would be approved and signed no earlier than 30 days after the final EIS is published.

Public Involvement and Scoping: USACE invites all affected federal, state, and local agencies, affected Federally-recognized Indian Tribes, other interested parties, and the general public to participate in the National Environmental Policy Act (NEPA) process during development of the DEIS. Besides providing information, this notice requests input on alternatives and issues of concern.

To ensure that public comments are considered in the DEIS preparation process, members of the public, interested persons and entities must submit their comments to USACE by mail, email, or at the Scoping

Meeting(s). All comments and suggestions must be submitted by June 20, 2023. All personally identifiable information (for example, name, address, etc.) voluntarily submitted by a commenter may be publicly accessible. Do not submit confidential business information or otherwise sensitive or protected information.

Scoping meeting(s) will be held at various locations (Slidell, Louisiana, and Jackson, Mississippi) during the scoping period which extends to June 20, 2023, to present information and receive comments from the public. Notification of the meeting(s) will be publicly announced in advance by USACE through press releases, special public notices, USACE social media platforms, and the project website <http://www.mvk.usace.army.mil/Missions/Programs-and-Project-Management/Project-Management/Pearl-River/>.

James A. Bodron,

Programs Director, Mississippi Valley Division.

[FR Doc. 2023-10599 Filed 5-17-23; 8:45 am]

BILLING CODE 3720-58-P

DEPARTMENT OF DEFENSE

Department of the Navy

Certificate of Alternate Compliance for USS George Washington (CVN 73)

AGENCY: Department of the Navy (DoN), Department of Defense (DoD).

ACTION: Notice of issuance of certificate of alternate compliance.

SUMMARY: The U.S. Navy hereby announces that a Certificate of Alternate Compliance has been issued for USS GEORGE WASHINGTON (CVN 73). Due to the special construction and purpose of this vessel, the Admiralty Counsel of the Navy has determined it is a vessel of the Navy which, due to its special construction and purpose, cannot comply fully with the navigation lights provisions of the International Regulations for Preventing Collisions at Sea, 1972 (72 COLREGS) without interfering with its special function as a naval ship. The intended effect of this notice is to warn mariners in waters where 72 COLREGS apply.

DATES: This Certificate of Alternate Compliance is effective May 18, 2023 and is applicable beginning May 4, 2023.

FOR FURTHER INFORMATION CONTACT: Lieutenant Commander J. Martin Bunt, JAGC, U.S. Navy, Admiralty Attorney, Office of the Judge Advocate General,

Admiralty and Claims Division (Code 15), 1322 Patterson Ave. SE, Suite 3000, Washington Navy Yard, DC 20374-5066, 202-685-5040, or admiralty@navy.mil.

SUPPLEMENTARY INFORMATION:

Background and Purpose. Executive Order (E.O.) 11964 of January 19, 1977 and 33 U.S.C. 1605 provide that the requirements of the International Regulations for Preventing Collisions at Sea, 1972 (72 COLREGS), as to the number, position, range, or arc of visibility of lights or shapes, as well as to the disposition and characteristics of sound-signaling appliances, shall not apply to a vessel or class of vessels of the Navy where the Secretary of the Navy shall find and certify that, by reason of special construction or purpose, it is not possible for such vessel(s) to comply fully with the provisions without interfering with the special function of the vessel(s). Notice of issuance of a Certificate of Alternate Compliance must be made in the **Federal Register**.

In accordance with 33 U.S.C. 1605, the Admiralty Counsel of the Navy, under authority delegated by the Secretary of the Navy, hereby finds and certifies that USS GEORGE WASHINGTON (CVN 73) is a vessel of special construction or purpose, and that, with respect to the position of the following navigational lights, it is not possible to comply fully with the requirements of the provisions enumerated in the 72 COLREGS without interfering with the special function of the vessel:

Rule 21(a), pertaining to the placement of the masthead lights over the fore and aft centerline of the ship; Annex I, paragraph 2(g), pertaining to the placement of the sidelights above the hull; Rule 21(b) pertaining to the visibility of the sidelights; Annex I, paragraph 3(a), pertaining to the placement of the forward masthead light in the forward quarter of the ship; and Annex I, Paragraph (2)(i)(iii) pertaining to the placement of the task lights.

The Admiralty Counsel of the Navy further finds and certifies that these navigational lights are in closest possible compliance with the applicable provision of the 72 COLREGS.

Authority: 33 U.S.C. 1605(c), E.O. 11964.

Dated: May 15, 2023.

A.R. Holt,

Lieutenant Commander, Judge Advocate General's Corps, U.S. Navy, Federal Register Liaison Officer.

[FR Doc. 2023-10630 Filed 5-17-23; 8:45 am]

BILLING CODE 3810-FF-P

DEPARTMENT OF EDUCATION**Applications for New Awards;
Transitioning Gang-Involved Youth to
Higher Education Program**

AGENCY: Office of Postsecondary Education, Department of Education.

ACTION: Notice.

SUMMARY: The Department of Education (Department) is issuing a notice inviting applications (NIA) for fiscal year (FY) 2023 for the Transitioning Gang-Involved Youth to Higher Education Program, Assistance Listing Number 84.116Y. This notice relates to the approved information collection under OMB control number 1894-0006.

DATES:

Applications Available: May 18, 2023.

Deadline for Transmittal of

Applications: July 17, 2023.

Deadline for Intergovernmental Review: September 15, 2023.

ADDRESSES: For the addresses for obtaining and submitting an application, please refer to our Common Instructions for Applicants to Department of Education Discretionary Grant Programs, published in the **Federal Register** on December 7, 2022 (87 FR 75045), and available at www.federalregister.gov/d/2022-26554. Please note that these Common Instructions supersede the version published on December 27, 2021.

FOR FURTHER INFORMATION CONTACT: Jymece Seward, U.S. Department of Education, 400 Maryland Avenue SW, 5th floor, Washington, DC 20202-4260. Telephone: 202-453-6138. Email: Jymece.Seward@ed.gov.

If you are deaf, hard of hearing, or have a speech disability and wish to access telecommunications relay services, please dial 7-1-1.

SUPPLEMENTARY INFORMATION:**Full Text of Announcement****I. Funding Opportunity Description**

Purpose of Program: The purpose of the Transitioning Gang-Involved Youth to Higher Education Program (TGIY) is to provide a funding opportunity for organizations that work directly with gang-involved youth to help such youth pursue higher education opportunities that will lead to certification or credentials. Such programs can include apprenticeships or other workforce preparation programs that promote job readiness upon completion of the program, while simultaneously providing essential wraparound services that include culturally competent social and emotional support.

Background: Recent research indicates that more than 1 million youth

are estimated to be involved in some type of gang, crew, or other group.¹ Youth gang involvement can negatively impact behavioral and mental health. Evidence suggests that exposure to adverse childhood experiences (ACEs), which are described as potentially traumatic events that can have negative lasting effects on health and well-being, can have a cumulative effect on later behavior, including potential future criminal justice system involvement. The greater the number of ACEs experienced in adolescence, the greater the impact on mental health into adulthood.² Furthermore, Frisby-Osman and Wood found that a range of ACEs, such as familial experiences, exposure to delinquency and violent victimization, and mental health difficulties, have been linked to a risk of gang involvement.

Gang involvement has almost immediate negative effects on educational achievement. According to the research, gang-involved youth are 30 percent less likely to complete high school compared with their gang-avoiding peers. However, regarding postsecondary matriculation, gang-affiliated youth who earn a GED went to college at twice the rate of their gang-avoiding peers with a GED.³ In interviews, gang-involved youth enrolled in community colleges reported that low expectations and negative stereotypes were part of their schooling experience.⁴ Accordingly, through this grant opportunity, the Department seeks to improve access to postsecondary education and outcomes for gang-involved youth.

College access is a multistep process for all students, but is especially difficult for students from low-income, non-college-educated families. These families typically do not possess the valued forms of social or cultural capital needed to access the networks that help students prepare for college.⁵ Most schools that serve primarily low-income students are unable to provide adequate

college advising or information about financial aid or to place students in the appropriate courses to increase their college readiness level.⁶ When college information is not available or frequently shared with high school students, their ability to build the necessary college knowledge and form a college-going identity is significantly weakened.

Youth who are gang-involved may benefit from holistic support systems through which their schools provide culturally competent social and emotional support, their families are included in their educational efforts, and they receive employment and resources and support for accessing financial assistance.⁷ Because prior research has suggested that stable employment can reduce the potential for future criminal justice system involvement, this program encourages applicants to collaborate with other organizations to build and support pathways to education and careers for gang-involved youth.

Community-based organizations are increasingly looking for institutional partners with which to collaborate.⁸ Community-academic partnerships are formed to work together toward shared goals to better reach and serve traditionally underserved populations. Partnerships can be expanded to include not only service delivery but also research and education. There can be many benefits to cross-sector partnerships relating to the shared work, including diverse perspectives and the combined expertise of academic partners and community knowledge.

The intent of this program is to support partnerships of institutions of higher education and other organizations that are best prepared to provide the supports and services necessary, to enable underserved youth, including youth with disabilities, to transition into postsecondary programs that will allow them to pursue a certificate, degree, or other credential, and, in doing so, reduce the risk of future criminal justice system involvement.

¹ Pyrooz, D. and Sweeten, G. (2015). Gang Membership Between Ages 5 and 17 Years in the United States. *Journal of Adolescent Health*, 1-6.

² Frisby-Osman, S. and Wood, J. (2020). Rethinking How We View Gang Members: An Examination into Affective, Behavioral, and Mental Health Predictors of UK Gang-Involved Youth. *Youth Justice* (20) 1, 93-112.

³ Pyrooz, D.C. (2014). From colors and guns to caps and gowns? The effect of gang membership on educational attainment. *Journal of Research in Crime and Delinquency*, 51(1), 56-87.

⁴ Gardenhire-Crooks, A., Collado, H., Martin, K., & Castro, A. (2010). *Terms of engagement: Men of color discuss their experiences in community college*. Oakland, CA: MDRC. Retrieved from: <http://files.eric.ed.gov/fulltext/ED508982.pdf>.

⁵ Tierney, W.G. (2009). Applying to college. *Qualitative Inquiry*, 15(1), 79-95.

⁶ Corwin, Z.B., Venegas, K.M., Olivarez, P.M., and Colyar, J.E. (2004). School counsel: How appropriate guidance affects college going. *Urban Education*, 39(4), 442-457.

⁷ Sharkey, J. (2015). How to Help Me Get Out of a Gang: Youth Recommendations to Family, School, Community, and Law Enforcement Systems. *Research Gate*, 64-100.

⁸ Liederman, S., Furco, A., Zapf, J., and Gross, M. (2003). Building partnerships with college campuses: Community perspectives. Washington, DC: Council for Independent Colleges/The Consortium for the Advancement of Private Higher Education's Engaging Communities and Campuses Grant Program.

Priorities: This notice contains one absolute priority, two competitive preference priorities, and two invitational priorities. The absolute priority and competitive preference priorities are from the Secretary's Supplemental Priorities and Definitions for Discretionary Grant Programs, published in the **Federal Register** on December 10, 2021 (86 FR 70612) (Supplemental Priorities).

Absolute Priority: For FY 2023 and any subsequent year in which we make awards from the list of unfunded applications from this competition, this priority is an absolute priority. Under 34 CFR 75.105(c)(3) we consider only applications that meet this priority.

The priority is:

Increasing Postsecondary Education Access, Affordability, Completion, and Post-Enrollment Success.

Projects that are designed to increase postsecondary access, affordability, completion, and success for underserved students by addressing one or more of the following priority areas:

(a) Increasing the number and proportion of underserved students who enroll in and complete postsecondary education programs, which may include strategies related to college preparation, awareness, application, selection, advising, counseling, and enrollment.

(b) Supporting the development and implementation of student success programs that integrate multiple comprehensive and evidence-based services or initiatives, such as academic advising, structured/guided pathways, career services, credit-bearing academic undergraduate courses focused on career, and programs to meet basic needs, such as housing, childcare and transportation, student financial aid, and access to technological devices.

(c) Increasing the number of individuals who return to the educational system and obtain a regular high school diploma, or its recognized equivalent for adult learners; enroll in and complete community college, college, or career and technical training; or obtain basic and academic skills, including English language learning, that they need to succeed in college—including community college—as well as career and technical education and/or the workforce.

Competitive Preference Priorities: For FY 2023 and any subsequent year in which we make awards from the list of unfunded applications from this competition, these priorities are competitive preference priorities. Under 34 CFR 75.105(c)(2)(i), we award up to an additional 10 points to an application for each competitive preference priority, depending on how

well the application meets these priorities. Applicants may respond to one or both competitive preference priorities, for a total of up to 20 additional points.

These priorities are:

Competitive Preference Priority 1—Meeting Student Social, Emotional, and Academic Needs (Up to 10 points).

Projects that are designed to improve students' social, emotional, academic, and career development, with a focus on underserved students, through one or more of the following priority areas:

(a) Creating a positive, inclusive, and identity-safe climate at institutions of higher education through one or more of the following activities:

(1) Fostering a sense of belonging and inclusion for underserved students. (Up to 2 points)

(2) Implementing evidence-based practices for advancing student success for underserved students. (Up to 2 points)

(3) Providing evidence-based professional development opportunities designed to build asset-based mindsets for faculty and staff on campus and that are inclusive with regard to race, ethnicity, culture, language, and disability status. (Up to 2 points)

(b) Fostering partnerships, including across government agencies (e.g., housing, human services, employment agencies), local educational agencies, community-based organizations, adult learning providers, and postsecondary education institutions, to provide comprehensive services to students and families that support students' social, emotional, mental health, and academic needs, and that are inclusive with regard to race, ethnicity, culture, language, and disability status. (Up to 4 points)

Competitive Preference Priority 2—Strengthening Cross-Agency Coordination and Community Engagement To Advance Systemic Change (Up to 10 points).

Projects that are designed to take a systemic evidence-based approach to improving outcomes for underserved students by coordinating efforts with Federal, State, or local agencies, or community-based organizations, that support students, to address one or both of the following:

(a) Justice policy. (Up to 5 points)

(b) College readiness. (Up to 5 points)

Invitational Priorities: For FY 2023 and any subsequent year in which we make awards from the list of unfunded applications from this competition, these priorities are invitational priorities. Under 34 CFR 75.105(c)(1), we do not give an application that meets these invitational priorities a

competitive or absolute preference over other applications.

These priorities are:

Invitational Priority 1—Organizations With a Demonstrated Record of Helping Gang-involved Youth Access Postsecondary Education.

Projects proposed by entities with prior experience working directly with gang-involved youth to help such youth pursue higher education opportunities. For the purpose of the invitational priorities, gang-involved youth means an individual, between the ages 14 and 24, who may participate in activities of a violent gang or who may face an increased risk of gang exposure due to proximity to communities with gang activity and/or gang-related conditions (e.g., community violence, vandalism, assault, gun violence, illegal drug trade, homicide) or other risk factors (e.g., domestic violence, child physical and sexual abuse, academic failure, low educational aspirations).

Invitational Priority 2—Promoting Equity in Student Access to Educational Resources and Opportunities.

Projects that are designed to promote educational equity and adequacy in resources and opportunity for gang-involved youth—

(a) In one or more of the following educational settings:

(1) High school.

(2) Career and technical education programs.

(3) Alternative schools and programs.

(4) Juvenile justice system or correctional facilities.

(b) That examines the sources of inequity and inadequacy and implement responses, and that may include one or more of the following:

(1) Improving the quality of educational and other evidence-based rehabilitative programs in juvenile justice facilities (such as detention facilities and secure and non-secure placements) or adult correctional facilities.

(2) Supporting re-entry of, and improving long-term outcomes for, youth and adults after release from juvenile justice system or correctional facilities by linking youth and adults to appropriate support, education, vocational rehabilitation, or workforce training programs.

Definitions: These definitions apply to the priorities and the selection criteria for this competition. The definitions of “demonstrates a rationale,” “evidence-based,” “logic model,” “project component,” and “relevant outcome” are from 34 CFR 77.1. The definition of “underserved student” is from the Supplemental Priorities.

Demonstrates a rationale means a key project component included in the project's logic model is informed by research or evaluation findings that suggest the project component is likely to improve relevant outcomes.

Disconnected youth means an individual, between the ages 14 and 24, who may be from a low-income background, experiences homelessness, is in foster care, is involved in the justice system, or is not working or not enrolled in (or at risk of dropping out of) an educational institution.

Evidence-based means the proposed project component is supported by evidence that demonstrates a rationale.

Logic model (also referred to as theory of action) means a framework that identifies key project components of the proposed project (*i.e.*, the active "ingredients" that are hypothesized to be critical to achieving the relevant outcomes) and describes the theoretical and operational relationships among the key project components and relevant outcomes.

Note: In developing logic models, applicants may want to use resources such as the Regional Educational Laboratory Program's (REL Pacific) Education Logic Model Application User Guide, available at <https://ies.ed.gov/ncee/rel/regions/pacific/pdf/ELMUserGuideJune2014.pdf>.

Other sources include: <https://ies.ed.gov/ncee/edlabs/regions/pacific/pdf/REL2014025.pdf>, <https://ies.ed.gov/ncee/edlabs/regions/pacific/pdf/REL2014007.pdf>, and https://ies.ed.gov/ncee/edlabs/regions/northeast/pdf/REL_2015057.pdf.

Project component means an activity, strategy, intervention, process, product, practice, or policy included in a project. Evidence may pertain to an individual project component or to a combination of project components (*e.g.*, training teachers on instructional practices for English learners and follow-on coaching for these teachers).

Relevant outcome means the student outcome(s) or other outcome(s) the key project component is designed to improve, consistent with the specific goals of the program.

Underserved student means a student (which may include students in postsecondary education or career and technical education, and adult learners, as appropriate) in one or both of the following subgroups:

- (a) A disconnected youth.
- (b) A student impacted by the justice system, including a formerly incarcerated student.

Program Authority: 20 U.S.C. 1138–1138d; the Explanatory Statement accompanying Division H of the

Consolidated Appropriations Act, 2023 (Pub. L. 117–328).

Note: Projects will be awarded and must be operated in a manner consistent with the nondiscrimination requirements contained in Federal civil rights laws.

Applicable Regulations: (a) The Education Department General Administrative Regulations in 34 CFR parts 75, 77, 79, 82, 84, 86, 97, 98, and 99. (b) The Office of Management and Budget Guidelines to Agencies on Governmentwide Debarment and Suspension (Nonprocurement) in 2 CFR part 180, as adopted and amended as regulations of the Department in 2 CFR part 3485. (c) The Uniform Administrative Requirements, Cost Principles, and Audit Requirements for Federal Awards in 2 CFR part 200, as adopted and amended as regulations of the Department in 2 CFR part 3474. (d) The Supplemental Priorities.

Note: The regulations in 34 CFR part 86 apply to institutions of higher education only.

II. Award Information

Type of Award: Discretionary grant.

Estimated Available Funds: \$4,950,000.

Contingent upon the availability of funds and the quality of applications, we may make additional awards in subsequent years from the list of unfunded applications from this competition.

Estimated Range of Awards: \$900,000 to \$990,000.

Estimated Average Size of Awards: \$990,000.

Maximum Award: We will not make an award exceeding \$990,000 for a single budget period of 36 months.

Note: The maximum award is based on a 3-year budget period. Applicants will need to prepare a multiyear budget request for up to 3 years.

Estimated Number of Awards: 5.

Note: The Department is not bound by any estimates in this notice.

Project Period: Up to 36 months.

III. Eligibility Information

1. *Eligible Applicants:* Eligible applicants are IHEs (as defined in section 101 of the Higher Education Act of 1965, as amended (20 U.S.C. 1001)) that are public or private nonprofit IHEs, and public and private nonprofit organizations and agencies that partner with institutions of higher education.

Note: If you are a nonprofit organization, under 34 CFR 75.51, you may demonstrate your nonprofit status by providing: (1) proof that the Internal Revenue Service currently recognizes the applicant as an organization to

which contributions are tax deductible under section 501(c)(3) of the Internal Revenue Code; (2) a statement from a State taxing body or the State attorney general certifying that the organization is a nonprofit organization operating within the State and that no part of its net earnings may lawfully benefit any private shareholder or individual; (3) a certified copy of the applicant's certificate of incorporation or similar document if it clearly establishes the nonprofit status of the applicant; or (4) any item described above if that item applies to a State or national parent organization, together with a statement by the State or parent organization that the applicant is a local nonprofit affiliate.

2. a. *Cost Sharing or Matching:* This competition does not require cost sharing or matching.

b. *Supplement-Not-Supplant:* This program does not involve supplement-not-supplant funding requirements.

c. *Indirect Cost Rate Information:* This program uses an unrestricted indirect cost rate. For more information regarding indirect costs, or to obtain a negotiated indirect cost rate, please see www2.ed.gov/about/offices/list/ocfo/intro.html.

d. *Administrative Cost Limitation:* This program does not include any program-specific limitation on administrative expenses. All administrative expenses must be reasonable and necessary and conform to Cost Principles described in 2 CFR part 200 subpart E of the Uniform Guidance.

3. *Subgrantees:* Under 34 CFR 75.708(b) and (c) a grantee under this competition may award subgrants—to directly carry out project activities described in its application—to entities listed in the grant application.

IV. Application and Submission Information

1. Application Submission

Instructions: Applicants are required to follow the Common Instructions for Applicants to Department of Education Discretionary Grant Programs, published in the **Federal Register** on December 7, 2022 (87 FR 75045), and available at www.federalregister.gov/d/2022-26554, which contain requirements and information on how to submit an application. Please note that these Common Instructions supersede the version published on December 27, 2021.

2. *Intergovernmental Review:* This program is subject to Executive Order 12372 and the regulations in 34 CFR part 79. Information about Intergovernmental Review of Federal

Programs under Executive Order 12372 is in the application package for this program.

3. *Funding Restrictions:* We reference regulations outlining funding restrictions in the *Applicable Regulations* section of this notice.

4. *Recommended Page Limit:* The application narrative is where you, the applicant, address the selection criteria that reviewers use to evaluate your application. We recommend that you (1) limit the application narrative to no more than 60 pages and (2) use the following standards:

- A “page” is 8.5” x 11”, on one side only, with 1” margins at the top, bottom, and both sides.

- Double-space (no more than three lines per vertical inch) all text in the application narrative, including titles, headings, footnotes, quotations, references, and captions as well as all text in charts, tables, figures, and graphs.

- Use a font that is either 12 point or larger, and no smaller than 10 pitch (characters per inch).

- Use one of the following fonts: Times New Roman, Courier, Courier New, or Arial.

The recommended 60-page limit applies only to the application narrative and does not apply to Part I, the cover sheet; Part II, the budget section, including the narrative budget justification; Part IV, the assurances and certifications; or the one-page abstract. We recommend that any application addressing the priorities include no more than three additional pages for each priority addressed.

Note: The Budget Information-Non-Construction Programs Form (ED 524) Sections A–C are not the same as the narrative response to the Budget section of the selection criteria.

V. Application Review Information

1. *Selection Criteria:* The following selection criteria for this program are from 34 CFR 75.210. The points assigned to each criterion are indicated in the parentheses next to the criterion. An applicant may earn up to a total of 100 points based on the selection criteria and up to 20 additional points under the competitive preference priorities, for a total score of up to 120 points. All applications will be evaluated based on the selection criteria as follows:

(a) *Quality of the project design.* (Maximum 20 points)

(1) The Secretary considers the quality of the design of the proposed project. In determining the quality of the design of the proposed project, the

Secretary considers the following factors:

(i) The extent to which the proposed project demonstrates a rationale (as defined in this notice). (Up to 5 points)

(ii) The extent to which the design of the proposed project is appropriate to, and will successfully address, the needs of the target population or other identified needs. (Up to 10 points)

(iii) The extent to which the proposed project will establish linkages with other appropriate agencies and organizations providing services to the target population. (Up to 5 points)

(b) *Quality of project services.*

(Maximum 20 points)

(1) The Secretary considers the quality of the services to be provided by the proposed project. In determining the quality of the services to be provided by the proposed project, the Secretary considers the quality and sufficiency of strategies for ensuring equal access and treatment for eligible project participants who are members of groups that have traditionally been underrepresented based on race, color, national origin, gender, age, or disability. (Up to 5 points)

(2) In addition, the Secretary considers the following factors:

(i) The extent to which the services to be provided by the proposed project are appropriate to the needs of the intended recipients or beneficiaries of those services. (Up to 5 points)

(ii) The likely impact of the services to be provided by the proposed project on the intended recipients of those services. (Up to 5 points)

(iii) The extent to which the services to be provided by the proposed project involve the collaboration of appropriate partners for maximizing the effectiveness of project services. (Up to 5 points)

(c) *Significance.* (Maximum 20 points)

(1) The Secretary considers the significance of the proposed project. In determining the significance of the proposed project, the Secretary considers the following factors:

(i) The potential contribution of the proposed project to increased knowledge or understanding of educational problems, issues, or effective strategies. (Up to 10 points)

(ii) The likelihood that the proposed project will result in system change or improvement. (Up to 10 points)

(d) *Quality of project personnel.*

(Maximum 20 points)

(1) The Secretary considers the quality of the personnel who will carry out the proposed project. In determining the quality of project personnel, the Secretary considers the extent to which the applicant encourages applications

for employment from persons who are members of groups that have traditionally been underrepresented based on race, color, national origin, gender, age, or disability. (Up to 8 points)

(2) In addition, the Secretary considers the following factors:

(i) The qualifications, including relevant training and experience, of the project director or principal investigator. (Up to 6 points)

(ii) The qualifications, including relevant training and experience, of key project personnel. (Up to 6 points)

(e) *Quality of the management plan.* (Maximum 10 points)

(1) The Secretary considers the quality of the management plan for the proposed project. In determining the quality of the management plan, the Secretary considers the following factors:

(i) The adequacy of the management plan to achieve the objectives of the proposed project on time and within budget, including clearly defined responsibilities, timelines, and milestones for accomplishing project tasks. (Up to 5 points)

(ii) How the applicant will ensure that a diversity of perspectives are brought to bear in the operation of the proposed project, including those of parents, teachers, the business community, a variety of disciplinary and professional fields, recipients or beneficiaries of services, or others, as appropriate. (Up to 5 points)

(f) *Quality of the project evaluation.* (Maximum 10 points)

(1) The Secretary considers the quality of the evaluation to be conducted of the proposed project. In determining the quality of the evaluation, the Secretary considers the following factors:

(i) The extent to which the goals, objectives, and outcomes to be achieved by the proposed project are clearly specified and measurable. (Up to 5 points)

(ii) The extent to which the methods of evaluation are thorough, feasible, and appropriate to the goals, objectives, and outcomes of the proposed project. (Up to 5 points)

2. *Review and Selection Process:* We remind potential applicants that in reviewing applications in any discretionary grant competition, the Secretary may consider, under 34 CFR 75.217(d)(3), the past performance of the applicant in carrying out a previous award, such as the applicant's use of funds, achievement of project objectives, and compliance with grant conditions. The Secretary may also consider whether the applicant failed to

submit a timely performance report or submitted a report of unacceptable quality.

In addition, in making a competitive grant award, the Secretary requires various assurances including those applicable to Federal civil rights laws that prohibit discrimination in programs or activities receiving Federal financial assistance from the Department (34 CFR 100.4, 104.5, 106.4, 108.8, and 110.23).

For this competition, a panel of up to three non-Federal reviewers will read, prepare a written evaluation of, and score all eligible applications using the selection criteria and the competitive preference priorities, if applicable, in this notice. The individual scores of the reviewers will be added and the sum divided by the number of reviewers to determine the peer review score. The Department may use more than one tier of reviews in evaluating grantees. The Department will prepare a rank order list of applications based solely on the evaluation of their quality according to the selection criteria and competitive preference priority points.

Tiebreaker: In the event there are two or more applications with the same final score, and there are insufficient funds to fully support each of these applications, the Department will apply the following procedure to determine which application or applications will receive an award:

First Tiebreaker: The first tiebreaker will be the highest average score for the selection criterion “Quality of the Project Design.” If a tie remains, the second tiebreaker will be utilized.

Second Tiebreaker: The second tiebreaker will be the highest average score for the selection criterion “Quality of Project Services.” If a tie remains, the 3rd tiebreaker will be utilized.

Third Tiebreaker: The third tiebreaker will be the highest average score for the selection criterion “Significance.” If a tie remains, the fourth tiebreaker will be utilized.

Fourth Tiebreaker: The fourth tiebreaker will be the highest average score for the selection criterion “Quality of the Project Evaluation.” If a tie remains, the fifth tiebreaker will be utilized.

Fifth Tiebreaker: The fifth tiebreaker will be the highest average score for the competitive preference priorities.

Sixth Tiebreaker: The sixth tiebreaker will be to select the application(s) proposed by organizations that work directly with gang-involved youth to help such youth pursue higher education opportunities.

Seventh Tiebreaker: The seventh tiebreaker will be to select the application(s) that propose to serve

geographic areas that have been previously underserved by this program.

3. Risk Assessment and Specific Conditions: Consistent with 2 CFR 200.206, before awarding grants under this competition the Department conducts a review of the risks posed by applicants. Under 2 CFR 200.208, the Secretary may impose specific conditions and, under 2 CFR 3474.10, in appropriate circumstances, high-risk conditions on a grant if the applicant or grantee is not financially stable; has a history of unsatisfactory performance; has a financial or other management system that does not meet the standards in 2 CFR part 200, subpart D; has not fulfilled the conditions of a prior grant; or is otherwise not responsible.

4. Integrity and Performance System: If you are selected under this competition to receive an award that over the course of the project period may exceed the simplified acquisition threshold (currently \$250,000), under 2 CFR 200.206(a)(2) we must make a judgment about your integrity, business ethics, and record of performance under Federal awards—that is, the risk posed by you as an applicant—before we make an award. In doing so, we must consider any information about you that is in the integrity and performance system (currently referred to as the Federal Awardee Performance and Integrity Information System (FAPIIS)), accessible through the System for Award Management. You may review and comment on any information about yourself that a Federal agency previously entered and that is currently in FAPIIS.

Please note that, if the total value of your currently active grants, cooperative agreements, and procurement contracts from the Federal Government exceeds \$10,000,000, the reporting requirements in 2 CFR part 200, appendix XII, require you to report certain integrity information to FAPIIS semiannually. Please review the requirements in 2 CFR part 200, appendix XII, if this grant plus all the other Federal funds you receive exceed \$10,000,000.

5. In General: In accordance with the Office of Management and Budget’s guidance located at 2 CFR part 200, all applicable Federal laws, and relevant Executive guidance, the Department will review and consider applications for funding pursuant to this notice inviting applications in accordance with—

(a) Selecting recipients most likely to be successful in delivering results based on the program objectives through an objective process of evaluating Federal award applications (2 CFR 200.205);

(b) Prohibiting the purchase of certain telecommunication and video surveillance services or equipment in alignment with section 889 of the National Defense Authorization Act of 2019 (Pub. L. 115–232) (2 CFR 200.216);

(c) Providing a preference, to the extent permitted by law, to maximize use of goods, products, and materials produced in the United States (2 CFR 200.322); and

(d) Terminating agreements in whole or in part to the greatest extent authorized by law if an award no longer effectuates the program goals or agency priorities (2 CFR 200.340).

VI. Award Administration Information

1. Award Notices: If your application is successful, we notify your U.S. Representative and U.S. Senators and send you a Grant Award Notification (GAN); or we may send you an email containing a link to access an electronic version of your GAN. We may notify you informally, also.

If your application is not evaluated or not selected for funding, we notify you.

2. Administrative and National Policy Requirements: We identify administrative and national policy requirements in the application package and reference these and other requirements in the *Applicable Regulations* section of this notice.

We reference the regulations outlining the terms and conditions of an award in the *Applicable Regulations* section of this notice and include these and other specific conditions in the GAN. The GAN also incorporates your approved application as part of your binding commitments under the grant.

3. Open Licensing Requirements: Unless an exception applies, if you are awarded a grant under this competition, you will be required to openly license to the public grant deliverables created in whole, or in part, with Department grant funds. When the deliverable consists of modifications to pre-existing works, the license extends only to those modifications that can be separately identified and only to the extent that open licensing is permitted under the terms of any licenses or other legal restrictions on the use of pre-existing works. Additionally, a grantee or subgrantee that is awarded competitive grant funds must have a plan to disseminate these public grant deliverables. This dissemination plan can be developed and submitted after your application has been reviewed and selected for funding. For additional information on the open licensing requirements, please refer to 2 CFR 3474.20.

4. *Reporting:* (a) If you apply for a grant under this competition, you must ensure that you have in place the necessary processes and systems to comply with the reporting requirements in 2 CFR part 170 should you receive funding under the competition. This does not apply if you have an exception under 2 CFR 170.110(b).

(b) At the end of your project period, you must submit a final performance report, including financial information, as directed by the Secretary. If you receive a multiyear award, you must submit an annual performance report that provides the most current performance and financial expenditure information as directed by the Secretary under 34 CFR 75.118. The Secretary may also require more frequent performance reports under 34 CFR 75.720(c). For specific requirements on reporting, please go to www.ed.gov/fund/grant/apply/appforms/appforms.html.

5. *Performance Measures:* For the purposes of the Department reporting under 34 CFR 75.110, the following performance measures will be used in assessing the effectiveness of the TGIY program:

(a) Number of project participants enrolled in a postsecondary education program.

(b) Number of project participants earning a certificate, degree, or other credential.

(c) Number of project participants active in internships, apprenticeships, or other work experiences.

These measures constitute the Department's indicators of success for this program. Consequently, we advise an applicant for an award under this program to give careful consideration to the operationalization of the measures in conceptualizing the approach and evaluation for its proposed project.

If funded, you will be required to collect and report data in your project's annual performance report (34 CFR 75.590).

6. *Continuation Awards:* In making a continuation award under 34 CFR 75.253, the Secretary considers, among other things: whether a grantee has made substantial progress in achieving the goals and objectives of the project; whether the grantee has expended funds in a manner that is consistent with its approved application and budget; and, if the Secretary has established performance measurement requirements, whether the grantee has made substantial progress in achieving the performance targets in the grantee's approved application.

In making a continuation award, the Secretary also considers whether the

grantee is operating in compliance with the assurances in its approved application, including those applicable to Federal civil rights laws that prohibit discrimination in programs or activities receiving Federal financial assistance from the Department (34 CFR 100.4, 104.5, 106.4, 108.8, and 110.23).

VII. Other Information

Accessible Format: On request to the program contact person listed under **FOR FURTHER INFORMATION CONTACT**, individuals with disabilities can obtain this document and a copy of the application package in an accessible format. The Department will provide the requestor with an accessible format that may include Rich Text Format (RTF) or text format (txt), a thumb drive, an MP3 file, braille, large print, audiotape, or compact disc, or other accessible format.

Electronic Access to This Document: The official version of this document is the document published in the **Federal Register**. You may access the official edition of the **Federal Register** and the Code of Federal Regulations at www.govinfo.gov. At this site you can view this document, as well as all other documents of this Department published in the **Federal Register**, in text or Portable Document Format (PDF). To use PDF, you must have Adobe Acrobat Reader, which is available free at the site.

You may also access documents of the Department published in the **Federal Register** by using the article search feature at www.federalregister.gov. Specifically, through the advanced search feature at this site, you can limit your search to documents published by the Department.

Nasser H. Paydar,

Assistant Secretary for Postsecondary Education.

[FR Doc. 2023-10625 Filed 5-17-23; 8:45 am]

BILLING CODE 4000-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP23-3-000]

Tres Palacios Gas Storage LLC; Notice of Availability of the Environmental Assessment for the Proposed Tres Palacios Cavern 4 Expansion Project

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) for the Tres Palacios Cavern 4 Expansion Project, proposed by Tres Palacios Gas

Storage LLC (Tres Palacios) in the above-referenced docket. Tres Palacios requests authorization to expand its certificated natural gas storage capacity at its existing natural gas storage facility (the Storage Facility) in Matagorda County, Texas.

The EA assesses the potential environmental effects of the construction and operation of the Tres Palacios Cavern 4 Expansion Project in accordance with the requirements of the National Environmental Policy Act (NEPA). The FERC staff concludes that approval of the proposed project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment.

The proposed Tres Palacios Cavern 4 Expansion Project includes the following facilities and activities:

- conversion of an existing third-party brine production well (Trull 11) into a natural gas storage cavern (Cavern 4);
- development of the Trull 11 well pad site for Cavern 4 (Cavern 4 Well Pad);
- construction of a 0.6-mile-long, 16-inch-diameter pipeline (new Cavern 4 Pipeline) including cathodic protection along the proposed pipeline, connecting Cavern 4 to the certificated facilities at the existing Storage Facility;
- abandonment in place of a 15,300 horsepower (HP) electric-motor driven centrifugal compressor unit;
- installation of a new 5,500 HP electric-motor driven reciprocating compressor unit;
- addition of a new 2.5 million British thermal units per hour dehydration unit;
- construction of various related facilities, including a new permanent access road for the Cavern 4 Well Pad; and

- non-jurisdictional facilities consisting of a new electric service line to the Cavern 4 Well Pad and a new fiber optic line from the Cavern 4 Well Pad to the Storage Facility.

The Commission mailed a copy of the *Notice of Availability* of the EA to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; potentially affected landowners and other interested individuals and groups; and newspapers and a library in the project area. The EA is only available in electronic format. It may be viewed and downloaded from the FERC's website (www.ferc.gov), on the natural gas environmental documents page (<https://www.ferc.gov/industries-data/natural-gas/environment/environmental->

documents). In addition, the EA may be accessed by using the eLibrary link on the FERC's website. Click on the eLibrary link (<https://elibrary.ferc.gov/elibrary/search>), select "General Search" and enter the docket number in the "Docket Number" field, excluding the last three digits (*i.e.*, CP23-3). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnlineSupport@ferc.gov or toll free at (866) 208-3676, or for TTY, contact (202) 502-8659.

The EA is not a decision document. It presents Commission staff's independent analysis of the environmental issues for the Commission to consider when addressing the merits of all issues in this proceeding. Any person wishing to comment on the EA may do so. Your comments should focus on the EA's disclosure and discussion of potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that the Commission has the opportunity to consider your comments prior to making its decision on this project, it is important that we receive your comments in Washington, DC, on or before 5:00 p.m. Eastern Time on June 12, 2023.

For your convenience, there are three methods you can use to file your comments to the Commission. The Commission encourages electronic filing of comments and has staff available to assist you at (866) 208-3676 or FercOnlineSupport@ferc.gov. Please carefully follow these instructions so that your comments are properly recorded.

(1) You can file your comments electronically using the eComment feature on the Commission's website (www.ferc.gov) under the link to FERC Online. This is an easy method for submitting brief, text-only comments on a project;

(2) You can also file your comments electronically using the eFiling feature on the Commission's website (www.ferc.gov) under the link to FERC Online. With eFiling, you can provide comments in a variety of formats by attaching them as a file with your submission. New eFiling users must first create an account by clicking on "eRegister." You must select the type of filing you are making. If you are filing a comment on a particular project, please select "Comment on a Filing"; or

(3) You can file a paper copy of your comments by mailing them to the Commission. Be sure to reference the

project docket number (CP23-3-000) on your letter. Submissions sent via the U.S. Postal Service must be addressed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Room 1A, Washington, DC 20426. Submissions sent via any other carrier must be addressed to: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

Filing environmental comments will not give you intervenor status, but you do not need intervenor status to have your comments considered. Only intervenors have the right to seek rehearing or judicial review of the Commission's decision. At this point in this proceeding, the timeframe for filing timely intervention requests has expired. Any person seeking to become a party to the proceeding must file a motion to intervene out-of-time pursuant to Rule 214(b)(3) and (d) of the Commission's Rules of Practice and Procedures (18 CFR 385.214(b)(3) and (d)) and show good cause why the time limitation should be waived. Motions to intervene are more fully described at <https://www.ferc.gov/how-intervene>.

Additional information about the project is available from the Commission's Office of External Affairs, at (866) 208-FERC, or on the FERC website (www.ferc.gov) using the eLibrary link. 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. Go to <https://www.ferc.gov/ferc-online/overview> to register for eSubscription.

Dated: May 12, 2023.

Kimberly D. Bose,
Secretary.

[FR Doc. 2023-10618 Filed 5-17-23; 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 & Oil Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP23-768-000.

Applicants: Texas Gas Transmission, LLC.

Description: § 4(d) Rate Filing: Clarifications and Alignment Filing to be effective 6/12/2023.

Filed Date: 5/12/23.

Accession Number: 20230512-5018.

Comment Date: 5 p.m. ET 5/24/23.

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: RP21-1188-004.

Applicants: Texas Eastern Transmission, LP.

Description: Refund Report: TETLP Base Rate Refund Report—RP21-1001-000 and RP21-1188-004 to be effective N/A.

Filed Date: 5/12/23.

Accession Number: 20230512-5071.

Comment Date: 5 p.m. ET 5/24/23.

Any person desiring to protest in any of 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: May 12, 2023.

Kimberly D. Bose,
Secretary.

[FR Doc. 2023-10617 Filed 5-17-23; 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 has received the following electric rate filings:

Docket Numbers: ER23–1221–002.
Applicants: Duquesne Light Company, PJM Interconnection, L.L.C.
Description: Tariff Amendment: Duquesne Light Company submits tariff filing per 35.17(b): Duquesne Amendment to Application BVDPT ER23–1221 to be effective 5/1/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5102.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1222–002.
Applicants: Duquesne Light Company, PJM Interconnection, L.L.C.
Description: Tariff Amendment: Duquesne Light Company submits tariff filing per 35.17(b): Duquesne Amendment to Application DEEP ER23–1222 to be effective 5/1/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5106.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1372–001.
Applicants: Gaucho Solar LLC.
Description: Tariff Amendment: Response to Deficiency Letter to be effective 5/1/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5109.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1492–000.
Applicants: Santa Paula Energy Storage, LLC.

Description: Supplement to March 28, 2023 Santa Paula Energy Storage, LLC tariff filing.

Filed Date: 5/12/23.

Accession Number: 20230512–5144.

Comment Date: 5 p.m. ET 5/19/23.

Docket Numbers: ER23–1574–001.
Applicants: PJM Interconnection, L.L.C.

Description: Tariff Amendment: ISA, SA No. 6849; Queue No. AE1–170 Supplement to Filing to be effective 3/6/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5127.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1869–000.
Applicants: Idaho Power Company.
Description: § 205(d) Rate Filing: Unexecuted GIA for Filing Appaloosa #590 to be effective 5/11/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5000.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1870–000.
Applicants: Dominion Energy South Carolina, Inc.

Description: § 205(d) Rate Filing: ODPD CIAC to be effective 7/12/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5025.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1872–000.
Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Designated Entity Agreement, SA No. 6891 between PJM and Potomac Edison to be effective 4/14/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5114.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1873–000.
Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Designated Entity Agreement, SA No. 6892 between PJM and PPL EU to be effective 4/14/2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5118.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1874–000.
Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Black Start Service Revisions to Enhance Fuel Assurance to be effective 1/29/2022.

Filed Date: 5/12/23.

Accession Number: 20230512–5135.

Comment Date: 5 p.m. ET 6/2/23.

Docket Numbers: ER23–1875–000.
Applicants: ISO New England Inc.
Description: ISO New England Inc. submits Capital Budget Quarterly Filing for First Quarter of 2023.

Filed Date: 5/12/23.

Accession Number: 20230512–5139.

Comment Date: 5 p.m. ET 6/2/23.

The filings are accessible in the Commission's eLibrary system (<https://elibrary.ferc.gov/idmws/search/fercensearch.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: May 12, 2023.

Kimberly D. Bose,
 Secretary.

[FR Doc. 2023–10619 Filed 5–17–23; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2003–0152, EPA–HQ–OAR–2011–0371, et al; FRL–10817–01–OAR]

Proposed Information Collection Request; Comment Request

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is planning to submit the below listed information collection requests (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act. Before doing so, EPA is soliciting public comments on specific aspects of the proposed information collection as described below. These are proposed extensions of the currently approved ICRs. 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.

DATES: Comments must be submitted on or before July 17, 2023.

ADDRESSES: Submit your comments, referencing the Docket ID numbers provided for each item in the text, online using www.regulations.gov (our preferred method), by email to a-and-r-docket@epa.gov, or by mail to: EPA Docket Center, Environmental Protection Agency, Mail Code 28221T, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

The EPA's policy is that all comments received will be included in the public docket without change including any personal information provided, unless the comment includes profanity, threats, information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.

FOR FURTHER INFORMATION CONTACT: Mr. Muntasir Ali, Sector Policies and Programs Division, (D243–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0833; email address: Ali.Muntasir@epa.gov.

SUPPLEMENTARY INFORMATION:

Supporting documents which explain in detail the information that the EPA will be collecting are available in the public docket for this ICR. The docket can be viewed online at www.regulations.gov or in person at the EPA Docket Center, WJC West, Room 3334, 1301 Constitution Ave. NW, Washington, DC.

The telephone number for the Docket Center is 202–566–1744. For additional information about EPA's public docket, visit <http://www.epa.gov/dockets>.

Pursuant to section 3506(c)(2)(A) of the PRA, EPA is soliciting comments and information to enable it to: (i) evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility; (ii) evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (iii) enhance the quality, utility, and clarity of the information to be collected; and (iv) 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 responses. Burden is defined at 5 CFR 1320.03(b). EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval. At that time, EPA will issue another **Federal Register** notice to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB.

General Abstract: For all the listed ICRs in this notice, owners and operators of affected facilities are required to comply with reporting and record keeping requirements for the general provisions of 40 CFR part 60, subpart A or part 63, subpart A, as well as the applicable specific standards. This includes submitting initial notifications, performance tests and periodic reports and results, and maintaining records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, or any period during which the monitoring system is inoperative. These reports are used by EPA to determine compliance with the standards.

(1) *Docket ID Number:* EPA–HQ–OAR–2007–0563; National Volatile Organic Compound Emission Standards for Consumer Products (40 CFR part 59, subpart C) (Renewal); EPA ICR Number 1764.09; OMB Control Number 2060–0348; Expiration date August 31, 2023.

Respondents: Manufacturers, importers, and named distributors of consumer products.

Respondent's obligation to respond: Mandatory (40 CFR part 59 subpart C).

Estimated number of respondents: 732.

Frequency of response: Initially. *Estimated annual burden:* 16,126 hours.

Estimated annual costs: \$1,765,427, includes \$0 annualized capital or O&M costs.

Changes in estimates: There is no change in the labor hours or capital and O&M costs to the respondents in this ICR compared to the previous ICR because the regulations have not changed over the past three years and are not anticipated to change over the next three years.

(2) *Docket ID Number:* EPA–HQ–OAR–2023–0115; NSPS for Nitric Acid Plants (40 CFR part 60, subparts G and Ga) (Renewal); EPA ICR Number 1056.14; OMB Control Number 2060–0019; Expiration date January 31, 2024.

Respondents: Nitric acid production units producing weak (30 to 70 percent) nitric acid.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subparts G and Ga).

Estimated number of respondents: 32. *Frequency of response:* Initially, semiannually.

Estimated annual burden: 2,534 hours.

Estimated annual cost: \$3,040,000, includes \$2,750,000 annualized capital or O&M costs.

Changes in estimates: There is a projected increase in burden due to an increase in the number of sources subject to the regulation.

(3) *Docket ID Number:* EPA–HQ–OAR–2003–0152; Compliance Assurance Monitoring Program (40 CFR part 64) (Renewal); EPA ICR Number 1663.11; OMB Control Number 2060–0376; Expiration date January 31, 2024.

Respondents: Title V sources with controlled pollutant-specific emissions units.

Respondent's obligation to respond: Mandatory (40 CFR part 64).

Estimated number of respondents: 21,565.

Frequency of response: Initially, semiannually, annually.

Estimated annual burden: 24,590 hours.

Estimated annual cost: \$999,211, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(4) *Docket ID Number:* EPA–HQ–OAR–2023–0137; NSPS for Sewage Sludge Incineration Units (40 CFR part 60, subpart LLLL) (Renewal); EPA ICR Number 2639.06; OMB Control Number 2060–0658; Expiration date January 31, 2024.

Respondents: Sewage sludge incineration unit facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart LLLL).

Estimated number of respondents: 8. *Frequency of response:* Initially, annually, semiannually.

Estimated annual burden: 1,560 hours.

Estimated annual cost: \$1,130,000, includes \$1,050,000 annualized capital or O&M costs.

Changes in estimates: There is a projected increase in burden due to an increase in the number of sources subject to the regulation.

(5) *Docket ID Number:* EPA–HQ–OAR–2023–0116; NSPS for Automobile and Light Duty Truck Surface Coating Operations (40 CFR part 60, subpart MM) (Renewal); EPA ICR Number 1064.21; OMB Control Number 2060–0034; Expiration date February 29, 2024.

Respondents: Automobile and light duty truck surface coating operations.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart MM).

Estimated number of respondents: 72. *Frequency of response:* Initially, semiannually, quarterly.

Estimated annual burden: 214,000 hours.

Estimated annual cost: \$24,400,000, includes \$128,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(6) *Docket ID Number:* EPA–HQ–OAR–2003–0120; National Volatile Organic Compound Emission Standards for Automobile Refinish Coatings (Renewal); EPA ICR Number 1765.10; OMB Control Number 2060–0353; Expiration date February 29, 2024.

Respondents: Manufacturers and importers of automobile refinishing coatings and coating components.

Respondent's obligation to respond: Mandatory (40 CFR part 59, subpart B).

Estimated number of respondents: 30. *Frequency of response:* Initially.

Estimated annual burden: 14 hours.

Estimated annual cost: \$980, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(7) *Docket ID Number:* EPA–HQ–OAR–2023–0110; NSPS for Metal Coil Surface Coating (40 CFR part 60, subpart TT) (Renewal); EPA ICR Number 0660.14; OMB Control Number 2060–0107; Expiration date March 31, 2024.

Respondents: Metal coil surface coating facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart TT).
Estimated number of respondents: 158.

Frequency of response: Initially, quarterly, semiannually

Estimated annual burden: 16,200 hours.

Estimated annual cost: \$1,950,000, includes \$170,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(8) *Docket ID Number:* EPA-HQ-OAR-2023-0111; NSPS for Asphalt Processing and Roofing Manufacturing (40 CFR part 60, subpart UU) (Renewal); EPA ICR Number 0661.14; OMB Control Number 2060-0002; Expiration date April 30, 2024.

Respondents: Asphalt processing and roofing manufacturing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart UU).

Estimated number of respondents: 144.

Frequency of response: Initially, semiannually.

Estimated annual burden: 34,100 hours.

Estimated annual cost: \$9,240,000, includes \$5,240,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(9) *Docket ID Number:* EPA-HQ-OAR-2023-0118; NSPS for Onshore Natural Gas Processing Plants (40 CFR part 60, subparts KKK and LLL) (Renewal); EPA ICR Number 1086.13; OMB Control Number 2060-0120; Expiration date April 30, 2024.

Respondents: Onshore natural gas processing plants.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subparts KKK and LLL).

Estimated number of respondents: 362.

Frequency of response: Semiannually.

Estimated annual burden: 67,530 hours.

Estimated annual cost: \$7,990,000, includes \$68,400 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(10) *Docket ID Number:* EPA-HQ-OAR-2023-0129; The Consolidated Air Rule (CAR) for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) (Renewal); EPA ICR Number 1854.14; OMB Control Number 2060-0443; Expiration date April 30, 2024.

Respondents: Synthetic organic chemical manufacturing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subparts Ka, Kb, VV, VVa, DDD, III, NNN, and RRR; 40 CFR part 61, subparts V, Y, and BB; and 40 CFR part 63, subparts F, G, H, and I).

Estimated number of respondents: 1,356.

Frequency of response: Initially, quarterly, semiannually, annually.

Estimated annual burden: 1,100,000 hours.

Estimated annual cost: \$128,000,000, includes \$64,000,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(11) *Docket ID Number:* EPA-HQ-OAR-2023-0130; NESHAP for Cellulose Products Manufacturing (40 CFR part 63, subpart UUUU) (Renewal); EPA ICR Number 1974.12; OMB Control Number 2060-0488; Expiration date June 30, 2024.

Respondents: Cellulose products manufacturing plants.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart UUUU).

Estimated number of respondents: 8.

Frequency of response: Initially, semiannually.

Estimated annual burden: 7,256 hours.

Estimated annual cost: \$954,624, includes \$120,135 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to anticipated shutdown of existing sources.

(12) *Docket ID Number:* EPA-HQ-OAR-2023-0109; NESHAP for Beryllium (40 CFR part 61, subpart C) (Renewal); EPA ICR Number 0193.14; OMB Control Number 2060-0092; Expiration date November 30, 2024.

Respondents: Facilities processing beryllium and its derivatives.

Respondent's obligation to respond: Mandatory (40 CFR part 61, subpart C).

Estimated number of respondents: 33.

Frequency of response: Initially, monthly.

Estimated annual burden: 2,670 hours.

Estimated annual cost: \$344,000, includes \$35,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(13) *Docket ID Number:* EPA-HQ-OAR-2023-0124; NESHAP for Aerospace Manufacturing and Rework

Facilities (40 CFR part 63, subpart GG) (Renewal); EPA ICR Number 1687.13; OMB Control Number 2060-0314; Expiration date November 30, 2024.

Respondents: Aerospace manufacturing and rework facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart GG).

Estimated number of respondents: 144.

Frequency of response: Initially, semiannually, annually.

Estimated annual burden: 154,130 hours.

Estimated annual cost: \$15,500,000, includes \$144,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(14) *Docket ID Number:* EPA-HQ-OAR-2023-0134; NESHAP for Gold Mine Ore Processing (40 CFR part 63, subpart EEEEEEE) (Renewal); EPA ICR Number 2383.06; OMB Control Number 2060-0659; Expiration date November 30, 2024.

Respondents: Gold mine ore processing and production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart EEEEEEE).

Estimated number of respondents: 21.

Frequency of response: Initially, semiannually, annually.

Estimated annual burden: 2,840 hours.

Estimated annual cost: \$556,000, includes \$227,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(15) *Docket ID Number:* EPA-HQ-OAR-2023-0114; NSPS for Electric Utility Steam Generating Units (40 CFR part 60, subpart Da) (Renewal); EPA ICR Number 1053.14; OMB Control Number 2060-0023; Expiration date December 31, 2024.

Respondents: Electric utility steam generating units.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart Da).

Estimated number of respondents: 732.

Frequency of response: Initially, semiannually, quarterly.

Estimated annual burden: 171,000 hours.

Estimated annual cost: \$31,000,000, includes \$11,000,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(16) *Docket ID Number:* EPA-HQ-OAR-2020-0627; NSPS for Petroleum

Refineries (40 CFR part 60, subpart J) (Renewal); EPA ICR Number 1054.15; OMB Control Number 2060–0022; Expiration date December 31, 2024.

Respondents: Petroleum refineries.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart J).

Estimated number of respondents: 130.

Frequency of response: Semiannually.
Estimated annual burden: 13,800 hours.

Estimated annual cost: \$2,450,000, includes \$809,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(17) *Docket ID Number:* EPA–HQ–OAR–2023–0113; NSPS for Portland Cement Plants (40 CFR part 60, subpart F) (Renewal); EPA ICR Number 1051.16; OMB Control Number 2060–0025; Expiration date December 31, 2024.

Respondents: Portland cement facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart F).

Estimated number of respondents: 92.
Frequency of response: Initially, semiannually.

Estimated annual burden: 14,100 hours.

Estimated annual cost: \$2,390,000, includes \$744,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to anticipated shutdown of existing sources.

(18) *Docket ID Number:* EPA–HQ–OAR–2020–0628; NSPS for Sulfuric Acid Plants (40 CFR part 60, subpart H) (Renewal); EPA ICR Number 2060–0041; OMB Control Number 1057.16; Expiration date December 31, 2024.

Respondents: Sulfuric acid manufacturing plants.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart H).

Estimated number of respondents: 53.
Frequency of response: Initially, semiannually.

Estimated annual burden: 13,500 hours.

Estimated annual cost: \$1,900,000, includes \$309,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(19) *Docket ID Number:* EPA–HQ–OAR–2023–0120; NSPS for Glass Manufacturing Plants (40 CFR part, 60 subpart CC) (Renewal); EPA ICR Number 1131.14; OMB Control Number 2060–0054; Expiration date December 31, 2024.

Respondents: Glass manufacturing plants.

Respondent's obligation to respond:

Mandatory (40 CFR part 60, subpart CC).

Estimated number of respondents: 41.

Frequency of response: Initially, semiannually.

Estimated annual burden: 850 hours.

Estimated annual cost: \$338,000, includes \$238,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(20) *Docket ID Number:* EPA–HQ–OAR–2020–0633; NSPS for Polymeric Coating of Supporting Substrates Facilities (40 CFR part 60, subpart VVV) (Renewal); EPA ICR Number 1284.13; OMB Control Number 2060–0181; Expiration date December 31, 2024.

Respondents: Facilities engaged in polymeric coating of supporting substrates.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart VVV).

Estimated number of respondents: 74.

Frequency of response: Initially, quarterly, semiannually.

Estimated annual burden: 16,400 hours.

Estimated annual cost: \$2,770,000, includes \$826,000 annualized capital or O&M costs.

Changes in estimates: There is a projected increase in burden due to an increase in the number of sources subject to the regulation.

(21) *Docket ID Number:* EPA–HQ–OAR–2023–0121; NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR part 60, subpart Dc) (Renewal); EPA ICR Number 1564.12; OMB Control Number 2060–0202; Expiration date December 31, 2024.

Respondents: Small industrial-commercial-institutional steam generating units.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart Dc).

Estimated number of respondents: 323.

Frequency of response: Initially, semiannually.

Estimated annual burden: 219,000 hours.

Estimated annual cost: \$38,300,000, includes \$12,600,000 annualized capital or O&M costs.

Changes in estimates: There is a projected increase in burden due to an increase in the number of sources subject to the regulation.

(22) *Docket ID Number:* EPA–HQ–OAR–2023–0112; NSPS for Calciners and Dryers in Mineral Industries (40 CFR part 60, subpart UUU) (Renewal); EPA ICR Number 0746.12; OMB Control Number 2060–0251; Expiration date December 31, 2024.

Respondents: Mineral processing plants with calciners and dryers.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart UUU).

Estimated number of respondents: 167.

Frequency of response: Initially, semiannually.

Estimated annual burden: 6,630 hours.

Estimated annual cost: \$887,000, includes \$109,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(23) *Docket ID Number:* EPA–HQ–OAR–2011–0371; National Volatile Organic Compound Emission Standards for Architectural Coatings (Renewal); EPA ICR Number 1750.10; OMB Control Number 2060–0393; Expiration date December 31, 2024.

Respondents: Manufacturers and importers of architectural coatings.

Respondent's obligation to respond: Mandatory (40 CFR part 59, subpart D).

Estimated number of respondents: 500.

Frequency of response: Initially, annually.

Estimated annual burden: 14,661 hours.

Estimated annual cost: \$1,484,441, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(24) *Docket ID Number:* EPA–HQ–OAR–2023–0135; NESHAP for Brick and Structural Clay Products Manufacturing (40 CFR part 63, subpart JJJJJ) (Renewal); EPA ICR Number 2509.03; OMB Control Number 2030–0047; Expiration date February 28, 2025.

Respondents: Brick and/or structural clay products manufacturing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart JJJJJ).

Estimated number of respondents: 69.

Frequency of response: Initially, semiannually.

Estimated annual burden: 20,963 hours.

Estimated annual cost: \$1,113,105 includes \$682 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(25) *Docket ID Number:* EPA–HQ–OAR–2023–0136; NESHAP for Clay Ceramics Manufacturing (40 CFR part 63, subpart KKKKK) (Renewal); EPA ICR Number 2510.03; OMB Control Number 2030–0048; Expiration date February 28, 2025.

Respondents: Clay ceramics manufacturing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart MM).

Estimated number of respondents: 3.
Frequency of response: Semiannually.
Estimated annual burden: 2,323 hours.

Estimated annual cost: \$221,905, includes \$99,119 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(26) *Docket ID Number:* EPA-HQ-OAR-2020-0629; NSPS for Primary and Secondary Emissions from Basic Oxygen Furnaces (40 CFR part 60, subparts N and Na) (Renewal); EPA ICR Number 1069.14; OMB Control Number 2060-0029; Expiration date February 28, 2025.

Respondents: Iron and steel plants that utilize basic oxygen furnaces.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subparts N and Na).

Estimated number of respondents: 13.
Frequency of response: Semiannually.
Estimated annual burden: 4,560 hours.

Estimated annual cost: \$562,000, includes \$21,600 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to anticipated shutdown of existing sources.

(27) *Docket ID Number:* EPA-HQ-OAR-2020-0630; NESHAP for Inorganic Arsenic Emissions from Glass Manufacturing Plants (40 CFR part 61, subpart N) (Renewal); EPA ICR Number 1081.14; OMB Control Number 2060-0043; Expiration date February 28, 2025.

Respondents: Glass manufacturing plants.

Respondent's obligation to respond: Mandatory (40 CFR part 61, subpart N).
Estimated number of respondents: 16.

Frequency of response: Initially, semiannually.
Estimated annual burden: 3,100 hours.

Estimated annual cost: \$423,000, includes \$56,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(28) *Docket ID Number:* EPA-HQ-OAR-2020-0632; NSPS for Lime Manufacturing (40 CFR part 60, subpart HH) (Renewal); EPA ICR Number 1167.14; OMB Control Number 2060-0063; Expiration date February 28, 2025.

Respondents: Lime production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart HH).

Estimated number of respondents: 41.
Frequency of response: Initially, semiannually.

Estimated annual burden: 3,820 hours.

Estimated annual cost: \$514,000, includes \$61,500 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(29) *Docket ID Number:* EPA-HQ-OAR-2020-0625; NESHAP for Vinyl Chloride (40 CFR part 61, subpart F) (Renewal); EPA ICR Number 0186.17; OMB Control Number 2060-0071; Expiration date February 28, 2025.

Respondents: Ethylene dichloride, polyvinyl chloride, and vinyl chloride facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 61, subpart F).

Estimated number of respondents: 16.
Frequency of response: Initially, quarterly.

Estimated annual burden: 6,540 hours.

Estimated annual cost: \$1,490,000, includes \$720,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(30) *Docket ID Number:* EPA-HQ-OAR-2020-0631; NSPS for Hot Mix Asphalt Facilities (40 CFR part 60, subpart I) (Renewal); EPA ICR Number 1127.14; OMB Control Number 2060-0083; Expiration date February 28, 2025.

Respondents: Hot mix asphalt facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart I).

Estimated number of respondents: 828.

Frequency of response: Initially.
Estimated annual burden: 4,120 hours.

Estimated annual cost: \$488,000, includes no annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(31) *Docket ID Number:* EPA-HQ-OAR-2023-0108; NSPS for Bulk Gasoline Terminals (40 CFR part 60, subpart XX) (Renewal); EPA ICR Number 0664.14; OMB Control Number 2060-0006; Expiration date February 28, 2025.

Respondents: Bulk gasoline terminals.

Respondent's obligation to respond: Mandatory (40 CFR part 60, subpart XX).

Estimated number of respondents: 214.

Frequency of response: Initially.
Estimated annual burden: 70,900 hours.

Estimated annual cost: \$8,320,000, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(32) *Docket ID Number:* EPA-HQ-OAR-2020-0622; NESHAP for Wood Furniture Manufacturing Operations (40 CFR part 63, subpart JJ) (Renewal); EPA ICR Number 1716.12; OMB Control Number 2060-0324; Expiration date February 28, 2025.

Respondents: Wood furniture manufacturing operations.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart JJ).

Estimated number of respondents: 230.

Frequency of response: Initially, quarterly, semiannually.

Estimated annual burden: 15,900 hours.

Estimated annual cost: \$1,890,000, includes \$12,900 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(33) *Docket ID Number:* EPA-HQ-OAR-2023-0126; NESHAP for Primary Aluminum Reduction Plants (40 CFR part 63, subpart LL) (Renewal); EPA ICR Number 1767.10; OMB Control Number 2060-0360; Expiration date February 28, 2025.

Respondents: Primary aluminum reduction facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart LL).

Estimated number of respondents: 8.

Frequency of response: Initially, quarterly, semiannually, annually.

Estimated annual burden: 52,300 hours.

Estimated annual cost: \$6,440,000, includes \$310,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to the anticipated shutdown of existing sources.

(34) *Docket ID Number:* EPA-HQ-OAR-2020-0624; NESHAP for Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills (40 CFR part 63, subpart MM) (Renewal); EPA ICR Number 1805.12; OMB Control Number 2060-0377; Expiration date February 28, 2025.

Respondents: Chemical recovery combustion sources at kraft, soda, sulfite, and stand-alone semichemical pulp mills.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart MM).

Estimated number of respondents: 104.

Frequency of response: Initially, semiannually.

Estimated annual burden: 116,982 hours.

Estimated annual cost: \$14,700,000, includes \$788,000 annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(35) *Docket ID Number:* EPA-HQ-OAR-2020-0636; NESHAP for Primary Lead Processing (40 CFR part 63, subpart TTT) (Renewal); EPA ICR Number 1856.13; OMB Control Number 2060-0414; Expiration date February 28, 2025.

Respondents: Facilities engaged in the smelting of lead from ores.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart TTT).

Estimated number of respondents: 1. *Frequency of response:* Quarterly, semiannually.

Estimated annual burden: 6,270 hours.

Estimated annual cost: \$912,000, includes \$169,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(36) *Docket ID Number:* EPA-HQ-OAR-2020-0623; NESHAP for Natural Gas Transmission and Storage (40 CFR part 63, subpart HHH) (Renewal); EPA ICR Number 1789.12; OMB Control Number 2060-0418; Expiration date February 28, 2025.

Respondents: Natural gas transmission and storage facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart HHH).

Estimated number of respondents: 73.

Frequency of response: Initially, semiannually.

Estimated annual burden: 3,780 hours.

Estimated annual cost: \$448,000, includes no annualized capital or O&M costs.

Changes in estimates: There is a projected increase in burden due to an increase in the number of sources subject to the regulation.

(37) *Docket ID Number:* EPA-HQ-OAR-2020-0638; NESHAP for Leather Finishing Operations (40 CFR part 63, subpart TTTT) (Renewal); EPA ICR Number 1985.11; OMB Control Number 2060-0478; Expiration date February 28, 2025.

Respondents: Leather finishing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 61, subpart TTTT).

Estimated number of respondents: 4. *Frequency of response:* Initially, annually.

Estimated annual burden: 138 hours. *Estimated annual cost:* \$16,300,

includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(38) *Docket ID Number:* EPA-HQ-OAR-2023-0122; NESHAP for Marine Tank Vessel Loading Operations (40 CFR part 63, subpart Y) (Renewal); EPA ICR Number 1679.12; OMB Control Number 2060-0289; Expiration date February 28, 2025.

Respondents: Marine tank vessel loading facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart Y). *Estimated number of respondents:* 804.

Frequency of response: Initially, semiannually, annually.

Estimated annual burden: 10,700 hours.

Estimated annual cost: \$1,260,000, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(39) *Docket ID Number:* EPA-HQ-OAR-2023-0123; NESHAP for Epoxy Resin and Non-Nylon Polyamide Production (40 CFR part 63, subpart W) (Renewal); EPA ICR Number 1681.11; OMB Control Number 2060-0290; Expiration date February 28, 2025.

Respondents: Epoxy resin and non-nylon polyamide resin production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart W).

Estimated number of respondents: 7.

Frequency of response: Initially, quarterly, semiannually.

Estimated annual burden: 3,940 hours.

Estimated annual cost: \$476,000, includes \$14,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(40) *Docket ID Number:* EPA-HQ-OAR-2023-0125; NESHAP for Shipbuilding and Ship Repair Facilities—Surface Coating (40 CFR part 63, subpart II) (Renewal); EPA ICR Number 1712.12; OMB Control Number 2060-0330; Expiration date February 28, 2025.

Respondents: Shipbuilding and ship repair surface coating facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart II).

Estimated number of respondents: 56. *Frequency of response:* Semiannually.

Estimated annual burden: 25,600 hours.

Estimated annual cost: \$3,000,000, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(41) *Docket ID Number:* EPA-HQ-OAR-2020-0634; NESHAP for the Secondary Lead Smelter Industry (40 CFR part 63, subpart X) (Renewal); EPA ICR Number 1686.13; OMB Control Number 2060-0296; Expiration date February 28, 2025.

Respondents: Secondary lead smelter facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart X).

Estimated number of respondents: 12. *Frequency of response:* Semiannually, annually.

Estimated annual burden: 21,700 hours.

Estimated annual cost: \$2,830,000, includes \$251,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(42) *Docket ID Number:* EPA-HQ-OAR-2023-0127; NESHAP for Pharmaceutical Production (40 CFR part 63, subpart GGG) (Renewal); EPA ICR Number 1781.10; OMB Control Number 2060-0358; Expiration date February 28, 2025.

Respondents: Pharmaceutical production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart GGG).

Estimated number of respondents: 27.

Frequency of response: Initially, semiannually.

Estimated annual burden: 44,300 hours.

Estimated annual cost: \$5,300,000, includes \$112,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(43) *Docket ID Number:* EPA-HQ-OAR-2023-0119; NESHAP for Beryllium Rocket Motor Fuel Firing (40 CFR part 61, subpart D) (Renewal); EPA ICR Number 1125.10; OMB Control Number 2060-0394; Expiration date February 28, 2025.

Respondents: Beryllium rocket motor fuel firing test sites.

Respondent's obligation to respond: Mandatory (40 CFR part 61, subpart D).

Estimated number of respondents: 1.
Frequency of response: Initially, monthly.

Estimated annual burden: 9 hours.
Estimated annual cost: \$1,110, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(44) *Docket ID Number:* EPA-HQ-OAR-2023-0128; NESHAP for Polyether Polyols Production (40 CFR part 63, subpart PPP) (Renewal); EPA ICR Number 1811.12; OMB Control Number 2060-0415; Expiration date February 28, 2025.

Respondents: Polyether polyols production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart PPP).

Estimated number of respondents: 23.
Frequency of response: Semiannually.
Estimated annual burden: 3,710 hours.

Estimated annual cost: \$429,000, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(45) *Docket ID Number:* EPA-HQ-OAR-2023-0133; NESHAP for Site Remediation (40 CFR part 63, subpart GGGGG) (Renewal); EPA ICR Number 2062.10; OMB Control Number 2060-0534; Expiration date February 28, 2025.

Respondents: Facilities that conduct site remediation activities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart GGGGG).

Estimated number of respondents: 30.
Frequency of response: Initially, semiannually.

Estimated annual burden: 19,724 hours.

Estimated annual cost: \$1,547,910, includes \$287,910 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(46) *Docket ID Number:* EPA-HQ-OAR-2020-0635; NESHAP for Primary Copper Smelters (40 CFR part 63, subpart QQQ) (Renewal); EPA ICR Number 1850.10; OMB Control Number 2060-0476; Expiration date February 28, 2025.

Respondents: Primary copper smelters.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart QQQ).

Estimated number of respondents: 2.
Frequency of response: Initially, semiannually, annually.

Estimated annual burden: 6,380 hours.

Estimated annual cost: \$761,000, includes \$5,480 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(47) *Docket ID Number:* EPA-HQ-OAR-2023-0117; NESHAP for Benzene Emissions from Benzene Storage Vessels and Coke Oven By-Product Recovery Plants (40 CFR part 61, subparts L and Y) (Renewal); EPA ICR Number 1080.17; OMB Control Number 2060-0185; Expiration date February 28, 2025.

Respondents: Benzene storage vessels and coke oven by-product recovery plants.

Respondent's obligation to respond: Mandatory (40 CFR part 61, subparts L and Y).

Estimated number of respondents: 13.
Frequency of response: Annually, semiannually.

Estimated annual burden: 1,730 hours.

Estimated annual cost: \$201,000, includes no annualized capital or O&M costs.

Changes in estimates: There is a projected decrease in burden due to a decrease in the number of sources subject to the regulation.

(48) *Docket ID Number:* EPA-HQ-OAR-2023-0131; NESHAP for Rubber Tire Manufacturing (40 CFR part 63, subpart XXXX) (Renewal); EPA ICR Number 1982.05; OMB Control Number 2060-0449; Expiration date February 28, 2025.

Respondents: Rubber tire manufacturing facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart XXXX).

Estimated number of respondents: 21.
Frequency of response: Initially, semiannually, annually.

Estimated annual burden: 5,870 hours.

Estimated annual cost: \$819,000, includes no annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(49) *Docket ID Number:* EPA-HQ-OAR-2017-0685; NESHAP for Metal Coil Surface Coating Plants (40 CFR part 63, subpart SSSS) (Renewal); EPA ICR Number 1957.11; OMB Control Number 2060-0487; Expiration date February 28, 2025.

Respondents: Metal coil surface coating sources.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart SSSS).

Estimated number of respondents: 48.
Frequency of response: Initially, semiannually.

Estimated annual burden: 16,838 hours.

Estimated annual cost: \$2,091,000, includes \$243,600 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

(50) *Docket ID Number:* EPA-HQ-OAR-2017-0357; NESHAP for Carbon Black, Ethylene, Cyanide, and Spandex (40 CFR part 63, subpart YY) (Renewal); EPA ICR Number 1983.11; OMB Control Number 2060-0489; Expiration date February 25, 2025.

Respondents: Carbon black, ethylene, cyanide, and spandex production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart YY).

Estimated number of respondents: 61.

Frequency of response: Initially, semiannually.

Estimated annual burden: 50,300 hours.

Estimated annual cost: \$ 9,340,000, includes \$4,015,500 annualized capital or O&M costs.

Changes in estimates: There is a projected increase in burden due to an increase in the number of sources subject to the regulation.

(51) *Docket ID Number:* EPA-HQ-OAR-2023-0132; NESHAP for Hydrochloric Acid Production (40 CFR part 63, subpart NNNNN) (Renewal); EPA ICR Number 2032.12; OMB Control Number 2060-0529; Expiration date February 28, 2025.

Respondents: Hydrochloric acid production facilities.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart NNNNN).

Estimated number of respondents: 19.

Frequency of response: Initially, semiannually.

Estimated annual burden: 22,000 hours.

Estimated annual cost: \$1,562,000, includes \$162,000 annualized capital or O&M costs.

Changes in estimates: There is no projected change in burden from the previous ICR.

Penny Lassiter,

Director, Sector Policies and Programs Division.

[FR Doc. 2023-10566 Filed 5-17-23; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY**[FRL-10990-01-OMS]****Establishment of National Environmental Youth Advisory Council****AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Notice; establishment of the National Environmental Youth Advisory Council.

SUMMARY: As required by the Federal Advisory Committee Act (FACA) that United States Environmental Protection Agency (EPA) is giving notice that it is establishing the National Environmental Youth Advisory Council (NEYAC). The purpose of this Council is to provide independent advice and recommendations to the EPA Administrator on how to increase EPA's efforts to address a range of environmental issues as they relate to youth communities, with an emphasis on communities below 29 years of age. The EPA has determined that this Federal advisory committee is necessary and in the public interest to provide a critical perspective on how the impacts of climate change and other environmental harms affects youth communities.

FOR FURTHER INFORMATION CONTACT: Grace Y. Smith in the Office of Public Engagement and Environmental Information in the Office of the Administrator (MC1448K) U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460; telephone: (202) 564-2558; email address: smith.grace.y@epa.gov.

SUPPLEMENTARY INFORMATION: The National Environmental Youth Advisory Council will be established for a two-year period. Copies of the committee charter will be filed with the appropriate congressional committees and the Library of Congress.

Grace Y. Smith,
Program Manager.

[FR Doc. 2023-10572 Filed 5-17-23; 8:45 am]

BILLING CODE P

ENVIRONMENTAL PROTECTION AGENCY**[FRL-10961-01-R5]****Great Lakes Advisory Board Notice for Virtual Meeting****AGENCY:** Environmental Protection Agency (EPA).**ACTION:** Notice of public meeting for Great Lakes Advisory Board.

SUMMARY: Pursuant to the Federal Advisory Committee Act (FACA), the Environmental Protection Agency (EPA) provides notice of a public meeting for the Great Lakes Advisory Board. Pre-registration is required. *Due to logistical circumstances, EPA is announcing this meeting with less than 15 calendar days public notice.*

DATES: This virtual public meeting will be held on May 31st, 2023, from 2 p.m. to 4 p.m. Central Daylight Time. Members of the public seeking to view the meeting must register by 2 p.m. Central Daylight Time on May 30th, 2023. Members of the public seeking to make comments relevant to issues discussed at the virtual meeting must register and indicate a request to make oral and/or written public comments in advance of the meeting. For information on how to register, please see How do I participate in the meeting below.

FOR FURTHER INFORMATION CONTACT: Todd Nettesheim, Acting Designated Federal Officer (DFO), at Nettesheim.Todd@epa.gov or 312-353-9153.

SUPPLEMENTARY INFORMATION:**I. General Information**

The GLAB is chartered in accordance with the Federal Advisory Committee Act (FACA) of 1972 (5 U.S.C., appendix 2, as amended) and 41 CFR 102-3.50(d). The Advisory Board provides advice and recommendations on matters related to the Great Lakes Restoration Initiative. The Advisory Board also advises on domestic matters related to implementation of the Great Lakes Water Quality Agreement between the U.S. and Canada. The major objectives are to provide advice and recommendations on: Great Lakes protection and restoration activities; long-term goals, objectives, and priorities for Great Lakes protection and restoration; and other issues identified by the Great Lakes Interagency Task Force/Regional Working Group.

II. How do I participate in the remote public meeting?**A. Remote Meeting**

This meeting will be conducted as a virtual meeting on May 31st, 2023, from 2 p.m. to 4 p.m. Central Daylight Time. You must register by 2:00 p.m. Central Daylight Time on May 30th, 2023, to receive information on how to participate. You may also submit written or oral comments for the committee by following the processes outlined below.

B. Registration

Individual registration is required for participation in this meeting. Information on registration for this meeting can be found at <https://event.capconcorp.com/form/view.php?id=168978>. When registering, please provide your name, email, organization, city, and state. Please also indicate whether you would like to provide oral and/or written comments during the meeting at the time of registration.

C. Procedures for Providing Public Comments

Oral Statements: In general, oral comments at this virtual conference will be limited to the Public Comments portions of the meeting agenda. Members of the public may provide oral comments limited to up to three minutes per individual or group and may submit further information as written comments. Persons interested in providing oral statements should register at <https://event.capconcorp.com/form/view.php?id=168978> for the meeting and indicate your interest to provide public comments. Oral commenters will be provided an opportunity to speak in the order in which their request was received by the DFO and to the extent permitted by the number of comments and the scheduled length of the meeting. Persons not able to provide oral comments during the meeting will be given an opportunity to provide written comments after the meeting.

Written Statements: Persons interested in providing written statements pertaining to this committee meeting may do so by indicating at <https://event.capconcorp.com/form/view.php?id=168978>. Written comments will be accepted before and after the public meeting for consideration by the Great Lakes Advisory Board members.

D. Availability of Meeting Materials

The meeting agenda and other materials for the virtual conference will be posted on the GLAB website at www.glab.us.

E. Accessibility

Persons with disabilities who wish to request reasonable accommodations to participate in this event may contact the Acting DFO at Nettesheim.todd@epa.gov or 312-353-9153 by 2 p.m. Central Daylight Time on May 23rd, 2023. All final meeting materials will be posted to the GLAB website in an accessible format following the meeting, as well as a written summary of this meeting.

Dated: May 9, 2023.

Debra Shore,

*Regional Administrator & Great Lakes
National Program Manager, US EPA Region
5.*

[FR Doc. 2023–10569 Filed 5–17–23; 8:45 am]

BILLING CODE 6560–50–P

EXPORT-IMPORT BANK

[Public Notice: EIB–2023–0004]

Application for Final Commitment for a Long-Term Loan or Financial Guarantee in Excess of \$100 Million: AP089463XX and AP089463XA

AGENCY: Export-Import Bank of the United States.

ACTION: Notice.

SUMMARY: This Notice is to inform the public the Export-Import Bank of the United States (“EXIM”) has received an application for final commitment for a long-term loan or financial guarantee in excess of \$100 million. Comments received within the comment period specified below will be presented to the EXIM Board of Directors prior to final action on this Transaction.

DATES: Comments must be received on or before June 12, 2023 to be assured of consideration before final consideration of the transaction by the Board of Directors of EXIM.

ADDRESSES: Comments may be submitted through *Regulations.gov* at *WWW.REGULATIONS.GOV*. To submit a comment, enter EIB–2023–0004 under the heading “Enter Keyword or ID” and select Search. Follow the instructions

provided at the Submit a Comment screen. Please include your name, company name (if any) and EIB–2023–0004 on any attached document.

SUPPLEMENTARY INFORMATION:

Reference: AP089463XX and AP089463XA

Purpose and Use:

Brief description of the purpose of the transaction: to support the export of U.S.-manufactured commercial aircraft and aircraft engines to Azerbaijan.

Brief non-proprietary description of the anticipated use of the items being exported: to provide air cargo transport services between Azerbaijan and other countries.

Parties:

Principal Supplier: The Boeing Company, GE Aircraft Engines
Obligor: Silk Way West Airlines LLC
Guarantor(s): Silk Way Development LLC, Silk Way Holding LLC, Silk Way Airlines LLC

Description of Items Being Exported:

Commercial cargo aircraft and spare engine.

Information on Decision: Information on the final decision for this transaction will be available in the “Summary Minutes of Meetings of Board of Directors” on *http://exim.gov/newsandevents/boardmeetings/board/*.

Confidential Information: Please note that this notice does not include confidential or proprietary business information; information which, if disclosed, would violate the Trade Secrets Act; or information which would jeopardize jobs in the United States by supplying information that

competitors could use to compete with companies in the United States.

Authority: Section 3(c)(10) of the Export-Import Bank Act of 1945, as amended (12 U.S.C. 635a(c)(10)).

Joyce B. Stone,

Assistant Corporate Secretary.

[FR Doc. 2023–10600 Filed 5–17–23; 8:45 am]

BILLING CODE 6690–01–P

FEDERAL COMMUNICATIONS COMMISSION

[FR ID 141365]

Open Commission Meeting Thursday, May 18, 2023

The Federal Communications Commission will hold an Open Meeting on the subjects listed below on Thursday, May 18, 2023, which is scheduled to commence at 10:30 a.m. in the Commission Meeting Room of the Federal Communications Commission, 45 L Street NE, Washington, DC. While attendance at the Open Meeting is available to the public, the FCC headquarters building is not open access and all guests must check in with and be screened by FCC security at the main entrance on L Street. Attendees at the Open Meeting will not be required to have an appointment but must otherwise comply with protocols outlined at: *www.fcc.gov/visit*. Open Meetings are streamed live at: *www.fcc.gov/live* and on the FCC’s YouTube channel.

Item No.	Bureau	Subject
1	Office of Engineering & Technology	<i>Title:</i> Amendment of Section 15.255 of the Commission’s Rules (ET Docket No. 21–264). <i>Summary:</i> The Commission will consider a Report and Order that would provide new opportunities for unlicensed field disturbance sensor devices, such as radars, to operate in the 57–71 GHz band (60 GHz band) and foster innovative products and services while ensuring coexistence with other unlicensed technologies and Federal incumbents in the band.
2	Wireless Tele-Communications and Office of Engineering & Technology.	<i>Title:</i> Expanding Flexible Use of the 12.2–12.7 GHz Band (WT Docket No. 20–443); Expanding Use of the 12.7–13.25 GHz Band for Mobile Broadband or Other Expanded Use (GN Docket No. 22–352). <i>Summary:</i> The Commission will consider a Report and Order and Further Notice of Proposed Rulemaking that would ensure that current and future satellite services are preserved and protected in the 12.2–12.7 GHz (12.2 GHz) band by declining to authorize mobile operations in the band, while further investigating the potential to expand fixed use or permit unlicensed use. The Notice of Proposed Rulemaking and Order would continue development of a pipeline of mid-band spectrum by proposing to authorize the 12.7–13.25 GHz (12.7 GHz band) for mobile broadband and other expanded uses.
3	Consumer & Governmental Affairs	<i>Title:</i> Advanced Methods to Target and Eliminate Unlawful Robocalls (CG Docket No. 17–59); Call Authentication Trust Anchor (WC Docket No. 17–97).

Item No.	Bureau	Subject
4	Media	<i>Summary:</i> The Commission will consider an Order, Further Notice, and Notice of Inquiry that would expand our call blocking requirements to ensure even greater protections for consumers. The item would enlist service providers in the fight against unwanted robocalls by extending our 24-hour traceback requirement to cover all voice service providers in the call path, enhancing existing requirements to effectively mitigate illegal traffic upon Commission notification and expanding our know-your-upstream-provider requirements to all voice service providers. The item would also seek comment on several other options to further enhance consumer protections, including a proposal to require terminating providers to offer analytics-based call blocking. <i>Title:</i> Restricted Adjudicatory Matter. <i>Summary:</i> The Commission will consider a restricted adjudicatory matter.

* * * * *

The meeting will be webcast at: www.fcc.gov/live. Open captioning will be provided as well as a text only version on the FCC website. Other reasonable accommodations for people with disabilities are available upon request. In your request, include a description of the accommodation you will need and a way we can contact you if we need more information. Last minute requests will be accepted but may be impossible to fill. Send an email to: fcc504@fcc.gov or call the Consumer & Governmental Affairs Bureau at 202–418–0530.

Press Access—Members of the news media are welcome to attend the meeting and will be provided reserved seating on a first-come, first-served basis. Following the meeting, the Chairwoman may hold a news conference in which she will take questions from credentialed members of the press in attendance. Also, senior policy and legal staff will be made available to the press in attendance for questions related to the items on the meeting agenda. Commissioners may also choose to hold press conferences. Press may also direct questions to the Office of Media Relations (OMR): MediaRelations@fcc.gov. Questions about credentialing should be directed to OMR.

Additional information concerning this meeting may be obtained from the Office of Media Relations, (202) 418–0500. Audio/Video coverage of the meeting will be broadcast live with open captioning over the internet from the FCC Live web page at www.fcc.gov/live.

Federal Communications Commission.

Dated: May 11, 2023.

Marlene Dortch,
Secretary.

[FR Doc. 2023–10660 Filed 5–17–23; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

[OMB 3060–0213; FR ID 140899]

Information Collection Being Reviewed by the Federal Communications Commission Under Delegated Authority

AGENCY: Federal Communications Commission.

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork burdens, and as required by the Paperwork Reduction Act of 1995 (PRA), the Federal Communications Commission (FCC or Commission) invites the general public and other Federal agencies to take this opportunity to comment on the following information collections. Comments are requested concerning: whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; the accuracy of the Commission's burden estimate; ways to enhance the quality, utility, and clarity of the information collected; ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology; and ways to further reduce the information collection burden on small business concerns with fewer than 25 employees. The FCC may not conduct or sponsor a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the PRA that does not display a valid OMB control number.

DATES: Written PRA comments should be submitted on or before July 17, 2023. If you anticipate that you will be

submitting comments but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Cathy Williams, FCC, via email to PRA@fcc.gov and to Cathy.Williams@fcc.gov.

FOR FURTHER INFORMATION CONTACT:

For additional information about the information collection, contact Cathy Williams at (202) 418–2918.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0213.

Title: Section 73.3525, Agreements for Removing Application Conflicts.

Form Number: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities; Not for profit institutions.

Number of Respondents and Responses: 38 respondents; 38 responses.

Estimated Time per Response: 0.25–1 hour.

Frequency of Response: On occasion reporting requirement; Third party disclosure requirement.

Total Annual Burden: 39 hours.

Total Annual Cost: \$91,200.

Nature and Extent of Confidentiality: There is no need for confidentiality with this collection of information.

Needs and Uses: The Commission is requesting an extension of this information collection in order to receive approval/clearance from the Office of Management and Budget for three years. 47 CFR 73.3525 requires applicants for a construction permit for a broadcast station to obtain approval from the FCC to withdraw, dismiss, or amend its application when that application is in conflict with another application pending before the FCC. This request for approval to withdraw, dismiss, or amend should contain a copy of the settlement agreement and an affidavit of each party to the agreement. The FCC staff uses this data to assure that the agreement complies with its rules and regulations and Section 311 of

the Communications Act of 1934, as amended.

Federal Communications Commission.

Marlene Dortch,

Secretary, Office of the Secretary.

[FR Doc. 2023–10576 Filed 5–17–23; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

[OMB 3060–1225; FR ID 141324]

Information Collection Being Reviewed by the Federal Communications Commission

AGENCY: Federal Communications Commission.

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork burdens, and as required by the Paperwork Reduction Act of 1995 (PRA), the Federal Communications Commission (FCC or Commission) invites the general public and other Federal agencies to take this opportunity to comment on the following information collections. Comments are requested concerning: whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; the accuracy of the Commission's burden estimate; ways to enhance the quality, utility, and clarity of the information collected; ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology; and ways to further reduce the information collection burden on small business concerns with fewer than 25 employees. The FCC may not conduct or sponsor a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the PRA that does not display a valid OMB control number.

DATES: Written PRA comments should be submitted on or before July 17, 2023. If you anticipate that you will be submitting comments but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Cathy Williams, FCC, via email PRA@fcc.gov and to Cathy.Williams@fcc.gov.

FOR FURTHER INFORMATION CONTACT: For additional information about the information collection, contact Cathy Williams at (202) 418–2918.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–1225.

Title: National Deaf-Blind Equipment Distribution Program.

Form Number: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Individuals or households; businesses or other for-profit entities; not-for-profit institutions; State, local, or Tribal governments.

Number of Respondents and Responses: 2,261 respondents; 6,989 responses.

Estimated Time per Response: 0.5 hours (30 minutes) to 40 hours.

Frequency of Response: Annual, semiannual, quarterly, and monthly reporting requirements; recordkeeping requirement; third-party disclosure requirement.

Obligation to Respond: Required to obtain or retain benefit. Statutory authority for this information collection is contained in sections 1, 4(i), 4(j), and 719 of the Communications Act, as amended, 47 U.S.C. 151, 154(i), 154(j), and 620.

Total Annual Burden: 20,890 hours.

Total Annual Cost: \$3,000.

Needs and Uses: Section 105 of the Twenty-First Century Communications and Video Accessibility Act of 2010 (CVAA) added section 719 to the Communications Act of 1934, as amended (the Act). Public Law 111–260, 124 Stat. 2751 (2010); Public Law 111–265, 124 Stat. 2795 (2010) (making technical corrections); 47 U.S.C. 620. Section 719 of the Act requires the Commission to establish rules that define as eligible for up to \$10,000,000 of support annually from the Interstate Telecommunications Relay Service Fund (TRS Fund) those programs that are approved by the Commission for the distribution of specialized customer premises equipment designed to make telecommunications service, internet access service, and advanced communications, including interexchange services and advanced telecommunications and information services, accessible by low-income individuals who are deafblind. 47 U.S.C. 620(a), (c). Accordingly, on August 5, 2016, the Commission released a Report and Order, document FCC 16–101, published at 81 FR 65948, September 26, 2016, adopting rules to establish the NDBEDP, also known as

“iCanConnect,” as a permanent program. See 47 CFR 64.6201 through 64.6219.

In document FCC 16–101, the Commission adopted rules requiring the following:

(a) Entities must apply to the Commission for certification to receive reimbursement from the TRS Fund for NDBEDP activities. The FCC's Consumer and Governmental Affairs Bureau certified 56 programs—one for each state, the District of Columbia, American Samoa, Guam, the Northern Mariana Islands, Puerto Rico, and the U.S. Virgin Islands—for a period of five years, from July 1, 2017, through June 30, 2022. Incumbent programs must apply to renew their certifications, if desired, and potential new entrants must also apply for certification by July 1, 2021.

(b) A program wishing to relinquish its certification before its certification expires must provide written notice of its intent to do so.

(c) Certified programs must disclose to the Commission actual or potential conflicts of interest.

(d) Certified programs must notify the Commission of any substantive change that bears directly on its ability to meet the qualifications necessary for certification.

(e) A certified entity may present written arguments and any relevant documentation as to why suspension or revocation of certification is not warranted.

(f) When a new entity is certified as a state's program, the previously certified entity must take certain actions to complete the transition to the new entity.

(g) Certified programs must require an applicant to provide verification that the applicant is deafblind.

(h) Certified programs must require an applicant to provide verification that the applicant meets the income eligibility requirement.

(i) Certified programs must re-verify the income and disability eligibility of an equipment recipient under certain circumstances.

(j) Certified programs must permit the transfer of an equipment recipient's account when the recipient relocates to another state.

(k) Certified programs must include an attestation on consumer application forms.

(l) Certified programs must conduct annual audits and submit to Commission-directed audits.

(m) Certified programs must document compliance with NDBEDP requirements, provide such documentation to the Commission upon

request, and retain such records for at least five years.

(n) Certified programs must submit reimbursement claims as instructed by the TRS Fund Administrator, and supplemental information and documentation as requested. In addition, the entity selected to conduct national outreach will submit claims for reimbursement on a quarterly basis.

(o) Certified programs must submit reports every six months as instructed by the NDBEDP Administrator. In addition, the entity selected to conduct national outreach will submit an annual report.

(p) Informal and formal complaints may be filed against NDBEDP certified programs, and the Commission may conduct such inquiries and hold such proceedings as it may deem necessary.

(q) Certified programs must include the NDBEDP whistleblower protections in appropriate publications.

Federal Communications Commission.

Marlene Dortch,

Secretary, Office of the Secretary.

[FR Doc. 2023–10577 Filed 5–17–23; 8:45 am]

BILLING CODE 6712–01–P

GOVERNMENT ACCOUNTABILITY OFFICE

Comptroller General's Advisory Council on Standards for Internal Control in the Federal Government; Meeting

AGENCY: Government Accountability Office.

ACTION: Notice of meeting.

SUMMARY: The U.S. Government Accountability Office (GAO) is revising *Standards for Internal Control in the Federal Government*, known as the Green Book, under its authority provided in the Federal Managers' Financial Integrity Act. As part of the revision process, GAO is holding a meeting of the Comptroller General's Advisory Council on Standards for Internal Control in the Federal Government (Council). The Comptroller General established the Council to provide input and recommendations on revisions to the Green Book. The purpose of the meeting is to discuss proposed revisions.

DATES: The meeting will be held on Wednesday, June 14, 2023, from 9:00 a.m. to 3:30 p.m.

ADDRESSES: The meeting will be held at the U.S. Government Accountability Office, 441 G Street NW, Washington, DC 20548, in Conference Room 2N30.

FOR FURTHER INFORMATION CONTACT: For information on the meeting or the Green Book, please contact Carrie Morrison, Assistant Director, Financial Management and Assurance, MorrisonC@gao.gov or (202) 512–4689. To request a reasonable accommodation (RA) for this meeting, email GAO's RA office at ReasonableAccommodations@gao.gov. Please request all accommodations at least 5 business days prior to the event (by June 7, 2023).

SUPPLEMENTARY INFORMATION: In the afternoon, members of the public will have an opportunity to address the Council with brief (5-minute) presentations on matters directly related to the proposed revisions. Any interested person who plans to attend the meeting as an observer must contact Carrie Morrison, Assistant Director, at (202) 512–4689, before June 7, 2023. To obtain access to the GAO building for the meeting, a form of picture identification must be presented to the GAO Security Desk. Please enter the building at the G Street entrance. The meeting agenda will be available upon request 1 week before the meeting.

Authority: 31 U.S.C. 3512(c), (d).

James Dalkin,

Director, Financial Management and Assurance, U.S. Government Accountability Office.

[FR Doc. 2023–10659 Filed 5–17–23; 8:45 am]

BILLING CODE 1610–02–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier: CMS–10401]

Agency Information Collection Activities: Proposed Collection; 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 (the 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 60 days for public comment on the proposed action. Interested persons are

invited to send comments regarding our burden estimates 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 must be received by July 17, 2023.

ADDRESSES: When commenting, please reference the document identifier or OMB control number. To be assured consideration, comments and recommendations must be submitted in any one of the following ways:

1. *Electronically.* You may send your comments electronically to <http://www.regulations.gov>. Follow the instructions for "Comment or Submission" or "More Search Options" to find the information collection document(s) that are accepting comments.

2. *By regular mail.* You may mail written comments to the following address: CMS, Office of Strategic Operations and Regulatory Affairs, Division of Regulations Development, Attention: Document Identifier/OMB Control Number: __, Room C4–26–05, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

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 N. Parham at (410) 786–4669.

SUPPLEMENTARY INFORMATION:

Contents

This notice sets out a summary of the use and burden associated with the following information collections. More detailed information can be found in each collection's supporting statement and associated materials (see **ADDRESSES**).

CMS–10401 Standards Related to Reinsurance, Risk Corridors, and Risk Adjustment

Under the 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 requires Federal agencies to publish a 60-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.

Information Collection

1. *Type of Information Collection Request:* Revision of the currently approved collection; *Title of Information Collection:* Standards Related to Reinsurance, Risk Corridors, and Risk Adjustment; *Use:* The data collection and reporting requirements will be used by HHS to run the permanent risk adjustment program, including validation of data submitted by issuers, on behalf of States that requested HHS to run it for them. Risk adjustment is one of three market stability programs established by the Patient Protection and Affordable Care Act and is intended to mitigate the impact of adverse selection in the individual and small group health insurance markets inside and outside of the Health Insurance Exchanges. HHS will also use this data to adjust the payment transfer formula for risk associated with high-cost enrollees. Issuers and providers can use the alternative reporting requirements for mental and behavioral health records described herein to comply with State privacy laws. *Form Number:* CMS–10401 (OMB control number: 0938–1155); *Frequency:* Annually; *Affected Public:* State, local, or Tribal governments; *Number of Respondents:* 650; *Total Annual Responses:* 3,250; *Total Annual Hours:* 4,154,150. (For policy questions regarding this collection contact Jacqueline Wilson at (301–492–4400).)

Dated: May 12, 2023.

William N. Parham, III,

Director, Paperwork Reduction Staff, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2023–10594 Filed 5–17–23; 8:45 am]

BILLING CODE P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2017–N–5925]

21st Century Cures Act: Annual Compilation of Notices of Updates From the Susceptibility Test Interpretive Criteria Web Page, 2021 and 2022 Updates; Request for Comments

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice; request for comments.

SUMMARY: The Food and Drug Administration (FDA, the Agency, or we) is announcing the availability of the Agency’s annual compilation of notices of updates to the Agency’s Susceptibility Test Interpretive Criteria web page with updates made in 2021 and 2022. The Agency established the Susceptibility Test Interpretive Criteria web page on December 13, 2017, and since establishment has provided updates to both the format of the web pages and to the susceptibility test interpretive criteria identified and recognized by FDA on the web pages. FDA is publishing this notice in accordance with procedures established by the 21st Century Cures Act (Cures Act).

DATES: This notice is published in the **Federal Register** on May 18, 2023.

ADDRESSES: You may submit either electronic or written comments and information as follows:

Electronic Submissions

Submit electronic comments in the following way:

- *Federal eRulemaking Portal:* <https://www.regulations.gov>. Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to <https://www.regulations.gov> will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else’s Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on <https://www.regulations.gov>.

- If you want to submit a comment with confidential information that you

do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see “Written/Paper Submissions” and “Instructions”).

Written/Paper Submissions

Submit written/paper submissions as follows:

- *Mail/Hand Delivery/Courier (for written/paper submissions):* Dockets Management Staff (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

- For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in “Instructions.”

Instructions: All submissions received must include the Docket No. FDA–2017–N–5925 for “Susceptibility Test Interpretive Criteria Recognized and Listed on the Susceptibility Test Interpretive web page; Request for Comments.” Received comments will be placed in the docket and, except for those submitted as “Confidential Submissions,” publicly viewable at <https://www.regulations.gov> or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240–402–7500.

- *Confidential Submissions—*To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states “THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.” The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on <https://www.regulations.gov>. Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as “confidential.” Any information marked as “confidential” will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA’s posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: [https://](https://www.regulations.gov)

www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf.

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to <https://www.regulations.gov> and insert the docket number, found in brackets in the heading of this document, into the "Search" box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240-402-7500.

FOR FURTHER INFORMATION CONTACT: Deborah (Wang) Kim, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 22, Rm. 6349, Silver Spring, MD 20993-0002, 301-796-9053, Deborah.Wang@fda.hhs.gov.

SUPPLEMENTARY INFORMATION:

I. Background

Section 511A of the Federal Food, Drug, and Cosmetic Act (the FD&C Act) (21 U.S.C. 360a-2), as added by section 3044 of the Cures Act (Pub. L. 114-255), was signed into law on December 13, 2016. This provision clarified FDA's authority to identify and efficiently update susceptibility test interpretive criteria, including through the recognition by FDA of standards established by standards development organizations (SDOs). It also clarified that sponsors of antimicrobial susceptibility testing devices may rely upon listed susceptibility test interpretive criteria to support premarket authorization of their devices, provided they meet certain conditions, which allows for a more streamlined process for incorporating up-to-date information into such devices.

In the **Federal Register** notice of December 13, 2017 (82 FR 58617), FDA announced the establishment of the Susceptibility Test Interpretive Criteria web page. This web page recognizes susceptibility test interpretive criteria established by an SDO that fulfills the requirements under section 511A(b)(2)(A) of the FD&C Act; identifies when FDA does not recognize, in whole or in part, susceptibility test interpretive criteria established by an SDO; and lists susceptibility test interpretive criteria identified by FDA outside the SDO process. The susceptibility test interpretive criteria listed by FDA on the Susceptibility Test Interpretive Criteria web page is deemed to be recognized as a standard under section 514(c)(1) of the FD&C Act (21 U.S.C. 360d(c)(1)). The Susceptibility Test Interpretive Criteria web page can be found at <https://www.fda.gov/STIC>.

On March 1, 2018, FDA published a notice in the **Federal Register** (83 FR 8883) requesting comments on FDA's initial susceptibility test interpretive criteria recognition and listing determinations on the Susceptibility Test Interpretive Criteria web page (<https://www.federalregister.gov/documents/2018/03/01/2018-04175/susceptibility-test-interpretive-criteria-recognized-and-listed-on-the-susceptibility-test>). FDA may consider information provided by interested third parties as a basis for evaluating new or updated interpretive criteria standards (section 511A(c)(2)(B) of the FD&C Act); third parties should submit any information they wish to convey to the Agency to Docket No. FDA-2017-N-5925. If comments are received, FDA will review those comments and will make, as appropriate, updates to the

recognized standards or susceptibility test interpretive criteria.

At least every 6 months after the establishment of the Susceptibility Test Interpretive Criteria web page, FDA is required, as appropriate to: (1) publish on that web page a notice recognizing new or updated susceptibility test interpretive criteria standards, or recognizing or declining to recognize parts of standards; (2) withdraw recognition of susceptibility test interpretive criteria standards, or parts of standards; and (3) make any other necessary updates to the lists published on the Susceptibility Test Interpretive Criteria web page (section 511A(c)(1)(A) of the FD&C Act). FDA has provided notices of updates on the Susceptibility Test Interpretive Criteria web page, which can be found here: <https://www.fda.gov/drugs/development-resources/notice-updates>. Interested parties may also sign up to receive emails informing them of these updates as they occur by using the link provided either on the main Susceptibility Test Interpretive Criteria web page (<https://www.fda.gov/STIC>) or on the updates page.

Once a year, FDA is required to compile the new notices published on the Susceptibility Test Interpretive Criteria web page, publish them in the **Federal Register**, and provide for public comment (see section 511A(c)(3) of the FD&C Act). This **Federal Register** notice satisfies that requirement. If comments are received, FDA will review them and make updates to the recognized standards or susceptibility test interpretive criteria as needed.

II. Annual Compilation of Notices, 2021: Web Page

TABLE 1—NOTICES OF UPDATES TO RECOGNIZED OR UPDATED SUSCEPTIBILITY TEST INTERPRETIVE CRITERIA BY DRUG ¹

Drug	Route of administration	Action taken	Therapeutic category	Date
Azithromycin	Oral, Injection	For <i>Neisseria gonorrhoeae</i> , FDA has reviewed susceptibility test interpretive criteria and concludes no changes are needed at this time. (Rationale available at https://www.fda.gov/drugs/development-resources/rationale-fdas-position-azithromycin-susceptible-only-breakpoint-neisseria-gonorrhoeae).	Antibacterial	10/14/21
Cefazolin	Injection	For Enterobacterales, FDA has reviewed susceptibility test interpretive criteria and the updated standard is recognized. (Rationale available at https://www.fda.gov/drugs/development-resources/rationale-fdas-position-cefazolin-breakpoints-enterobacterales)	Antibacterial	10/14/21
Cefiderocol	Injection	FDA recognizes M100 MIC standard for <i>Enterobacteriaceae</i>	Antibacterial	10/14/21
Ceftolozane; tazobactam.	Injection	FDA recognizes M100 standard for <i>Haemophilus influenzae</i>	Antibacterial	10/14/21
Colistimethate	Injection	FDA does not recognize M100 standard for <i>Enterobacteriaceae</i>	Antibacterial	10/14/21
Imipenem/ cilastatin/ relebactam.	Injection	FDA recognizes M100 standard for <i>Enterobacteriaceae</i> , <i>Pseudomonas aeruginosa</i> , and anaerobes.	Antibacterial	10/14/21
Lefamulin	Oral, Injection	FDA recognizes M100 standard for <i>Staphylococcus aureus</i> , <i>Streptococcus pneumoniae</i> , and <i>Haemophilus influenzae</i> .	Antibacterial	10/14/21
Polymyxin B	Injection	FDA does not recognize M100 standard for <i>Enterobacteriaceae</i> and <i>Pseudomonas aeruginosa</i> .	Antibacterial	10/14/21

TABLE 1—NOTICES OF UPDATES TO RECOGNIZED OR UPDATED SUSCEPTIBILITY TEST INTERPRETIVE CRITERIA BY DRUG ¹—Continued

Drug	Route of administration	Action taken	Therapeutic category	Date
Telithromycin	Oral	FDA has removed telithromycin susceptibility test interpretive criteria as the drug is no longer approved in any application under section 505 of the FD&C Act (21 U.S.C. 355) (see 84 FR 47309).	Antibacterial	10/14/21

¹ M100 standard in the table refers to Clinical and Laboratory Standards Institute (CLSI) Performance Standards for Antimicrobial Susceptibility Testing, 31st ed. CLSI supplement M100; 2021.

III. Annual Compilation of Notices, 2022: Susceptibility Test Interpretive Criteria Web Page

A. Updates to Standards Recognition

As of May 18, 2022, the following standards are no longer recognized: “Clinical and Laboratory Standards

Institute (CLSI). Performance Standards for Antimicrobial Susceptibility Testing, 31st ed. CLSI supplement M100. Wayne, PA: Clinical and Laboratory Standards Institute; 2021.”

As of May 18, 2022, with certain exceptions, FDA recognizes the standards published in: “Clinical and

Laboratory Standards Institute (CLSI). Performance Standards for Antimicrobial Susceptibility Testing, 32nd ed. CLSI supplement M100. Wayne, PA: Clinical and Laboratory Standards Institute; 2022.”

B. Updates by Drug

TABLE 2—NOTICES OF UPDATES TO RECOGNIZED OR UPDATED SUSCEPTIBILITY TEST INTERPRETIVE CRITERIA BY DRUG ¹

Drug	Route of administration	Action taken	Therapeutic category	Date
Amoxicillin and clavulanate.	Oral	FDA does not recognize M100 standard and provides susceptibility test interpretive criteria for <i>Haemophilus influenzae</i> .	Antibacterial	5/17/22
Cefadroxil	Oral	FDA removed the statement “ <i>Susceptibility of Enterobacteriaceae to cefadroxil may be deduced from testing cefazolin.</i> ” (Rationale available at https://www.fda.gov/drugs/development-resources/rationale-fdas-position-cefadroxil .)	Antibacterial	4/27/22
Cefazolin	Injection	FDA does not recognize M100 standard for cefazolin as a surrogate to predict susceptibility of oral cephalosporins when used for the treatment of uncomplicated urinary tract infections caused by <i>Escherichia coli</i> , <i>Klebsiella pneumoniae</i> and <i>Proteus mirabilis</i> . (Rationale available at https://www.fda.gov/drugs/development-resources/rationale-fdas-position-use-cefazolin-breakpoints-surrogate-determining-breakpoints-oral .)	Antibacterial	10/20/22
Cefoxitin	Injection	FDA recognizes M100 standard for <i>Staphylococcus aureus</i> complex and <i>Staphylococcus lugdunensis</i> . FDA recognizes M100 disk diffusion standard for <i>Staphylococcus epidermidis</i> and other <i>Staphylococcus</i> spp.	Antibacterial	10/4/22
Ceftolozane and tazobactam.	Injection	FDA recognizes M100 disk diffusion standard for Enterobacterales	Antibacterial	5/17/22
Lefamulin	Oral, Injection	FDA does not recognize M100 disk diffusion standard and provides susceptibility test interpretive criteria for <i>Streptococcus pneumoniae</i> and <i>Haemophilus influenzae</i> .	Antibacterial	5/17/22
Oxacillin	Injection	FDA concurs with the revised CLSI susceptibility test interpretive criteria for <i>Staphylococcus</i> by species level. (Rationale available at https://www.fda.gov/drugs/development-resources/rationale-fdas-position-oxacillin-breakpoints-staphylococcus). FDA references Cefoxitin susceptibility test interpretive for <i>Staphylococcus</i> spp. as a surrogate test.	Antibacterial	10/4/22
Piperacillin and tazobactam.	Injection	FDA does not recognize M100 standard for Enterobacterales	Antibacterial	5/17/22

¹ M100 standard in the table refers to CLSI Performance Standards for Antimicrobial Susceptibility Testing, 32nd ed. CLSI supplement M100; 2022.

Dated: May 15, 2023.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2023–10603 Filed 5–17–23; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES**Food and Drug Administration****[Docket No. FDA-2007-D-0369]****Product-Specific Guidance for Ethinyl Estradiol; Segesterone Acetate; Draft Guidance for Industry; Availability****AGENCY:** Food and Drug Administration, HHS.**ACTION:** Notice of availability.

SUMMARY: The Food and Drug Administration (FDA or Agency) is announcing the availability of a draft guidance for industry entitled “Draft Guidance for Ethinyl Estradiol; Segesterone Acetate.” The draft guidance, when finalized, will provide product-specific recommendations on, among other things, the design of bioequivalence (BE) studies to support abbreviated new drug applications (ANDAs) for ethinyl estradiol; segesteron acetate vaginal ring.

DATES: Submit either electronic or written comments on the draft guidance by July 17, 2023, to ensure that the Agency considers your comment on this draft guidance before it begins work on the final version of the guidance.

ADDRESSES: You may submit comments on any guidance at any time as follows:

Electronic Submissions

Submit electronic comments in the following way:

- *Federal eRulemaking Portal:* <https://www.regulations.gov>. Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to <https://www.regulations.gov> will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else’s Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on <https://www.regulations.gov>.

- If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see “Written/Paper Submissions” and “Instructions”).

Written/Paper Submissions

Submit written/paper submissions as follows:

- *Mail/Hand Delivery/Courier (for written/paper submissions):* Dockets Management Staff (HFA-305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

- For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in “Instructions.”

Instructions: All submissions received must include the Docket No. FDA-2007-D-0369 for “Draft Guidance for Ethinyl Estradiol; Segesterone Acetate.” Received comments will be placed in the docket and, except for those submitted as “Confidential Submissions,” publicly viewable at <https://www.regulations.gov> or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240-402-7500.

- **Confidential Submissions**—To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states “THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.” The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on <https://www.regulations.gov>. Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as “confidential.” Any information marked as “confidential” will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA’s posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: <https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf>.

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to <https://www.regulations.gov> and insert the

docket number, found in brackets in the heading of this document, into the “Search” box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240-402-7500.

You may submit comments on any guidance at any time (see 21 CFR 10.115(g)(5)).

Submit written requests for single copies of the draft guidance to the Division of Drug Information, Center for Drug Evaluation and Research, Food and Drug Administration, 10001 New Hampshire Ave., Hillandale Building, 4th Floor, Silver Spring, MD 20993-0002. Send one self-addressed adhesive label to assist that office in processing your requests. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the draft guidance document.

FOR FURTHER INFORMATION CONTACT: Christine Le, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 75, Rm. 4714, Silver Spring, MD 20993-0002, 301-796-2398, PSG-Questions@fda.hhs.gov.

SUPPLEMENTARY INFORMATION:**I. Background**

In the **Federal Register** of June 11, 2010 (75 FR 33311), FDA announced the availability of a guidance for industry entitled “Bioequivalence Recommendations for Specific Products,” which explained the process that would be used to make product-specific guidances available to the public on FDA’s website at: <https://www.fda.gov/drugs/guidance-compliance-regulatory-information/guidances-drugs>.

As described in that guidance, FDA adopted this process to develop and disseminate product-specific guidances and to provide a meaningful opportunity for the public to consider and comment on the guidances. This notice announces the availability of a draft guidance for ethinyl estradiol; segesteron acetate vaginal ring.

FDA initially approved new drug application (NDA) 209627 ANNOVERA (ethinyl estradiol; segesteron acetate) in August 2018. We are now issuing a draft guidance for industry on, among other things, BE recommendations for generic ethinyl estradiol; segesteron acetate vaginal ring (“Draft Guidance for Ethinyl Estradiol; Segesterone Acetate”).

In March 2021, TherapeuticsMD, Inc. (“TherapeuticsMD”) submitted a citizen petition requesting, among other things, that FDA refuse to receive and refuse to approve any ANDAs seeking approval to market a generic version of ANNOVERA unless certain BE criteria are met.

(Docket No. FDA-2021-P-0293, available at <https://www.regulations.gov>). FDA is separately responding to TherapeuticsMD's citizen petition today as well.

This draft guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the current thinking of FDA on the design of BE studies to support ANDAs for ethinyl estradiol; segesterone acetate. It does not establish any rights for any person and is not binding on FDA or the public. You can use an alternative approach if it satisfies the requirements of the applicable statutes and regulations.

II. Paperwork Reduction Act of 1995

FDA tentatively concludes that this draft guidance contains no collection of information. Therefore, clearance by the Office of Management and Budget under the Paperwork Reduction Act of 1995 is not required.

III. Electronic Access

Persons with access to the internet may obtain the draft guidance at <https://www.fda.gov/drugs/guidance-compliance-regulatory-information/guidances-drugs>, <https://www.fda.gov/regulatory-information/search-fda-guidance-documents>, or <https://www.regulations.gov>.

Dated: May 15, 2023.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2023-10604 Filed 5-17-23; 8:45 am]

BILLING CODE 4164-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA-2005-D-0460]

Pediatric Drug Development: Regulatory Considerations—Complying With the Pediatric Research Equity Act and Qualifying for Pediatric Exclusivity Under the Best Pharmaceuticals for Children Act; Draft Guidance for Industry; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of availability.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a draft guidance for industry entitled “Pediatric Drug Development: Regulatory Considerations—Complying With the Pediatric Research Equity Act and

Qualifying for Pediatric Exclusivity Under the Best Pharmaceuticals for Children Act.” This draft guidance, when finalized, is intended to provide recommendations to industry on complying with the pediatric study requirements under the Pediatric Research Equity Act (PREA), and to describe the process for qualifying for pediatric exclusivity and the protections that pediatric exclusivity offers under the Best Pharmaceuticals for Children Act (BPCA). Combining discussion of PREA and the BPCA together in regulatory guidance emphasizes the sponsor's need to consider both laws when developing pediatric drugs and biological products.

DATES: Submit either electronic or written comments on the draft guidance by July 17, 2023 to ensure that the Agency considers your comment on this draft guidance before it begins work on the final version of the guidance.

ADDRESSES: You may submit comments on any guidance at any time as follows:

Electronic Submissions

Submit electronic comments in the following way:

- **Federal eRulemaking Portal:** <https://www.regulations.gov>. Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to <https://www.regulations.gov> will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else's Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on <https://www.regulations.gov>.

- If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see “Written/Paper Submissions” and “Instructions”).

Written/Paper Submissions

Submit written/paper submissions as follows:

- **Mail/Hand Delivery/Courier (for written/paper submissions):** Dockets Management Staff (HFA-305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.
- For written/paper comments submitted to the Dockets Management

Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in “Instructions.”

Instructions: All submissions received must include the Docket No. FDA-2005-D-0460 for “Pediatric Drug Development: Regulatory Considerations—Complying With the Pediatric Research Equity Act and Qualifying for Pediatric Exclusivity Under the Best Pharmaceuticals for Children Act.” Received comments will be placed in the docket and, except for those submitted as “Confidential Submissions,” publicly viewable at <https://www.regulations.gov> or at the Dockets Management Staff between 9 a.m. and 4 p.m., Monday through Friday, 240-402-7500.

- **Confidential Submissions—**To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states “THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.” The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on <https://www.regulations.gov>. Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as “confidential.” Any information marked as “confidential” will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA's posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: <https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf>.

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to <https://www.regulations.gov> and insert the docket number, found in brackets in the heading of this document, into the “Search” box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240-402-7500.

You may submit comments on any guidance at any time (see 21 CFR 10.115(g)(5)).

Submit written requests for single copies of the draft guidance to the Division of Drug Information, Center for Drug Evaluation and Research, Food and Drug Administration, 10001 New Hampshire Ave., Hillandale Building, 4th Floor, Silver Spring, MD 20993–0002, or the Office of Communication, Outreach, and Development, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 3128, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your requests. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the draft guidance document.

FOR FURTHER INFORMATION CONTACT: Rosemary Addy, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 22, Rm. 6430, Silver Spring, MD 20993–0002, 301–796–1640, pedsdrugs@fda.hhs.gov; or Diane Maloney, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 7301, Silver Spring, MD 20993–0002, 240–402–7911.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a draft guidance for industry entitled “Pediatric Drug Development: Regulatory Considerations—Complying With the Pediatric Research Equity Act and Qualifying for Pediatric Exclusivity Under the Best Pharmaceuticals for Children Act.” This draft guidance is intended to provide recommendations on how to comply with the pediatric study requirements under sections 505B of the Federal Food, Drug, and Cosmetic Act (FD&C Act) (21 U.S.C. 355c) (PREA), and to qualify for pediatric exclusivity under section 505A of the FD&C Act (21 U.S.C. 355a) (BPCA). This guidance also incorporates recommendations based on FDA’s Retrospective Review.¹

PREA requires that certain applications (or supplements to applications) submitted under section 505 of the FD&C Act (21 U.S.C. 355) or under section 351 of the Public Health Service Act (42 U.S.C. 262) (specifically, any application that is subject to PREA) must either include pediatric assessments or reports on the

molecularly targeted pediatric cancer investigation (as appropriate), or a request for waiver and/or deferral (see section 505B(a)(1), (a)(4), and (a)(5) of the FD&C Act). To ensure that sponsors thoroughly consider a pediatric clinical development program earlier in their overall clinical development program, PREA requires sponsors to submit an initial pediatric study plan during the investigational phase of development (see section 505B(e) of the FD&C Act). PREA also authorizes FDA to require holders of approved applications for drugs and biological products, who are not seeking approval for one of the changes specified, to submit pediatric assessments under certain circumstances (see section 505B(b) of the FD&C Act).

Under the BPCA, certain applications may qualify for 6 months of exclusivity if the following conditions are met: (1) FDA determines that information relating to the use of a drug in the pediatric population may produce health benefits in that population; (2) FDA issues a written request (WR) for studies of that drug in pediatric populations and the applicant agrees to the request; (3) the studies are completed using appropriate formulations for each age group and within the requested time; and (4) the reports of the studies are submitted and accepted by FDA (see section 505A(b)(1) and (c)(1) of the FD&C Act). In accepting or rejecting the reports, FDA determines whether the studies fairly respond to the WR, have been reported in accordance with filing requirements, and otherwise qualify for pediatric exclusivity (see section 505A(d)(4) of the FD&C Act).

With respect to content, this draft guidance addresses pediatric assessments, molecularly targeted pediatric cancer investigations, pediatric study plans, waivers and deferrals (including deferral extensions), labeling considerations, the noncompliance process, the relationship of the PREA requirements to pediatric exclusivity, and the reporting of adverse events for products subject to PREA and the BPCA. Additionally, the draft guidance includes a description of the mechanisms FDA uses to obtain pediatric studies, how industry can obtain a WR and what it includes, how study reports should be submitted to FDA for filing, the criteria to qualify for pediatric exclusivity, the nature and scope of pediatric exclusivity, and the information that should be submitted in support of a request for a pediatric exclusivity determination.

With respect to its discussion of PREA, this guidance, along with the draft guidance for industry entitled

“Pediatric Drug Development Under the Pediatric Research Equity Act and the Best Pharmaceuticals for Children Act: Scientific Considerations,” revises and replaces the draft guidance for industry entitled “How to Comply With the Pediatric Research Equity Act” (2005 draft guidance; 70 FR 53233, September 7, 2005).² In addition to addressing certain PREA-related topics covered in the 2005 draft guidance, this draft guidance also addresses certain changes to PREA that have occurred since 2005.

This draft guidance is being issued consistent with FDA’s good guidance practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the current thinking of FDA on “Pediatric Drug Development: Regulatory Considerations—Complying With the Pediatric Research Equity Act and Qualifying for Pediatric Exclusivity Under the Best Pharmaceuticals for Children Act.” It does not establish any rights for any person and is not binding on FDA or the public. You can use an alternative approach if it satisfies the requirements of the applicable statutes and regulations.

II. Paperwork Reduction Act of 1995

While this guidance contains no collection of information, it does refer to previously approved FDA collections of information. Therefore, clearance by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3521) is not required for this guidance. The previously approved collections of information are subject to review by OMB under the PRA. The collections of information in 21 CFR part 312 for investigational new drug applications and 21 CFR part 314 for new drug applications and abbreviated new drug applications have been approved under OMB control numbers 0910–0014 and 0910–0001, respectively. The collections of information in 21 CFR parts 601 and 610 pertaining to biologics license applications have been approved under OMB control number 0910–0338. The collections of information in 42 U.S.C. 262(k) for biosimilar applications have been approved under OMB control number 0910–0718. The collections of information in 21 CFR 201.56 and 201.57 regarding labeling requirements for prescription drugs have been approved under OMB control number 0910–0572. The collections of

¹ This review was conducted pursuant to section 505B(f)(5) of the FD&C Act and is described in more detail in a report available at <https://www.fda.gov/media/78050/download>.

² This guidance also addresses certain topics previously addressed in the guidance for industry entitled “Qualifying for Pediatric Exclusivity Under Section 505A of the Federal Food, Drug, and Cosmetic Act.” That guidance was withdrawn August 7, 2013 (78 FR 48175).

information in 21 CFR part 201, subpart C regarding over-the-counter products have been approved under OMB control number 0910–0340. The collections of information in 21 CFR part 316 regarding orphan drug product development have been approved under OMB control number 0910–0167.

III. Electronic Access

Persons with access to the internet may obtain the draft guidance at <https://www.fda.gov/drugs/guidance-compliance-regulatory-information/vaccines-drugs>, <https://www.fda.gov/vaccines-blood-biologics/guidance-compliance-regulatory-information-biologics/biologics-guidances>, <https://www.fda.gov/regulatory-information/search-fda-guidance-documents>, or <https://www.regulations.gov>.

Dated: May 15, 2023.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2023–10610 Filed 5–17–23; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2005–D–0460]

Pediatric Drug Development Under the Pediatric Research Equity Act and the Best Pharmaceuticals for Children Act: Scientific Considerations; Draft Guidance for Industry; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of availability.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a draft guidance for industry entitled “Pediatric Drug Development Under the Pediatric Research Equity Act and the Best Pharmaceuticals for Children Act: Scientific Considerations.” This draft guidance addresses selected clinical, scientific, and ethical issues involved in developing drugs, including biological products, for pediatric use when such drug products are subject to the Pediatric Research Equity Act (PREA) and/or the Best Pharmaceuticals for Children Act (BPCA). This draft guidance is intended to assist industry in obtaining the data and information necessary to support the approval of drug products in pediatric populations. This draft guidance does not address the clinical development of drug products that are not subject to either PREA or the BPCA.

DATES: Submit either electronic or written comments on the draft guidance by July 17, 2023 to ensure that the Agency considers your comment on this draft guidance before it begins work on the final version of the guidance.

ADDRESSES: You may submit comments on any guidance at any time as follows:

Electronic Submissions

Submit electronic comments in the following way:

- **Federal eRulemaking Portal:** <https://www.regulations.gov>. Follow the instructions for submitting comments. Comments submitted electronically, including attachments, to <https://www.regulations.gov> will be posted to the docket unchanged. Because your comment will be made public, you are solely responsible for ensuring that your comment does not include any confidential information that you or a third party may not wish to be posted, such as medical information, your or anyone else’s Social Security number, or confidential business information, such as a manufacturing process. Please note that if you include your name, contact information, or other information that identifies you in the body of your comments, that information will be posted on <https://www.regulations.gov>.

- If you want to submit a comment with confidential information that you do not wish to be made available to the public, submit the comment as a written/paper submission and in the manner detailed (see “Written/Paper Submissions” and “Instructions”).

Written/Paper Submissions

Submit written/paper submissions as follows:

- **Mail/Hand Delivery/Courier (for written/paper submissions):** Dockets Management Staff (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

- For written/paper comments submitted to the Dockets Management Staff, FDA will post your comment, as well as any attachments, except for information submitted, marked and identified, as confidential, if submitted as detailed in “Instructions.”

Instructions: All submissions received must include the Docket No. FDA–2005–D–0460 for “Pediatric Drug Development Under the Pediatric Research Equity Act and the Best Pharmaceuticals for Children Act: Scientific Considerations.” Received comments will be placed in the docket and, except for those submitted as “Confidential Submissions,” publicly viewable at <https://www.regulations.gov> or at the Dockets Management Staff

between 9 a.m. and 4 p.m., Monday through Friday, 240–402–7500.

- **Confidential Submissions—**To submit a comment with confidential information that you do not wish to be made publicly available, submit your comments only as a written/paper submission. You should submit two copies total. One copy will include the information you claim to be confidential with a heading or cover note that states “THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION.” The Agency will review this copy, including the claimed confidential information, in its consideration of comments. The second copy, which will have the claimed confidential information redacted/blacked out, will be available for public viewing and posted on <https://www.regulations.gov>. Submit both copies to the Dockets Management Staff. If you do not wish your name and contact information to be made publicly available, you can provide this information on the cover sheet and not in the body of your comments and you must identify this information as “confidential.” Any information marked as “confidential” will not be disclosed except in accordance with 21 CFR 10.20 and other applicable disclosure law. For more information about FDA’s posting of comments to public dockets, see 80 FR 56469, September 18, 2015, or access the information at: <https://www.govinfo.gov/content/pkg/FR-2015-09-18/pdf/2015-23389.pdf>.

Docket: For access to the docket to read background documents or the electronic and written/paper comments received, go to <https://www.regulations.gov> and insert the docket number, found in brackets in the heading of this document, into the “Search” box and follow the prompts and/or go to the Dockets Management Staff, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852, 240–402–7500.

You may submit comments on any guidance at any time (see 21 CFR 10.115(g)(5)).

Submit written requests for single copies of the draft guidance to the Division of Drug Information, Center for Drug Evaluation and Research, Food and Drug Administration, 10001 New Hampshire Ave., Hillandale Bldg., 4th Floor, Silver Spring, MD 20993–0002, or the Office of Communication, Outreach and Development, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 3128, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your requests. See the **SUPPLEMENTARY**

INFORMATION section for electronic access to the draft guidance document.

FOR FURTHER INFORMATION CONTACT:

Rosemary Addy, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 22, Rm. 6430, Silver Spring, MD 20993-0002, 301-796-2200, pedsdrugs@fda.hhs.gov; or Diane Maloney, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 7301, Silver Spring, MD 20993-0002, 240-402-7911.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a draft guidance for industry entitled “Pediatric Drug Development Under the Pediatric Research Equity Act and the Best Pharmaceuticals for Children Act: Scientific Considerations.” This draft guidance addresses selected clinical, scientific, and ethical issues involved in developing drugs for pediatric use when such drugs are subject to PREA and/or the BPCA. This draft guidance, along with the draft guidance entitled “Pediatric Drug Development: Regulatory Considerations—Complying With the Pediatric Research Equity Act and Qualifying for Pediatric Exclusivity Under the Best Pharmaceuticals for Children Act,” revises and replaces the draft guidance entitled “How to Comply with the Pediatric Research Equity Act.”¹ This draft guidance also addresses certain additional topics that FDA has not previously addressed in guidance.

The purpose of this draft guidance is to assist industry in obtaining the data and information needed to support approval of drug products in pediatric populations. Specifically, this draft guidance describes considerations regarding data in pediatric patients with particular discussion regarding formulation development, nonclinical information, clinical pharmacology, and safety information. Additionally, the draft guidance discusses pediatric extrapolation, timing of pediatric studies, and drug development for the neonatal population. This draft guidance does not address the clinical development of drugs that are not subject to either PREA or the BPCA.

This draft guidance is being issued consistent with FDA’s good guidance

practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the current thinking of FDA on “Pediatric Drug Development Under the Pediatric Research Equity Act and the Best Pharmaceuticals for Children Act: Scientific Considerations.” It does not establish any rights for any person and is not binding on FDA or the public. You can use an alternative approach if it satisfies the requirements of the applicable statutes and regulations.

II. The Paperwork Reduction Act of 1995

While this guidance contains no collection of information, it does refer to previously approved FDA collections of information. Therefore, clearance by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3521) is not required for this guidance. The previously approved collections of information are subject to review by OMB under the PRA. The collections of information in 21 CFR parts 50 and 56 for protection of human subjects and institutional review boards, have been approved under OMB control number 0910–0130. The collections of information in 21 CFR 210 and 211 for current good manufacturing practice have been approved under OMB control number 0910–0139. The collections of information in 21 CFR part 312 for investigational new drug applications and 21 CFR part 314 for new drug applications and abbreviated new drug applications have been approved under OMB control numbers 0910–0014 and 0910–0001, respectively. The collections of information in 21 CFR parts 601 and 610 for biologics license applications have been approved under OMB control number 0910–0338. The collections of information in 42 U.S.C. 262(k) and 21 U.S.C. 379g for biosimilar applications have been approved under OMB control number 0910–0718. The collections of information in 21 CFR 201.56 and 201.57 regarding labeling requirements for prescription drugs have been approved under OMB control number 0910–0572. The collections of information in 21 CFR part 201, subpart C regarding over-the-counter products have been approved under OMB control number 0910–0340. The collections of information in 21 CFR part 316 regarding orphan drug product development are approved under OMB control number 0910–0167.

III. Electronic Access

Persons with access to the internet may obtain the draft guidance at <https://www.fda.gov/drugs/guidance-compliance-regulatory-information/>

[guidances-drugs](https://www.fda.gov/guidances-drugs), <https://www.fda.gov/vaccines-blood-biologics/guidance-compliance-regulatory-information-biologics/biologics-guidances>, <https://www.fda.gov/regulatory-information/search-fda-guidance-documents>, or <https://www.regulations.gov>.

Dated: May 15, 2023.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2023–10611 Filed 5–17–23; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2023–N–0008]

Patient Engagement Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA or the Agency) announces a forthcoming public advisory committee meeting of the Center for Devices and Radiological Health (CDRH) Patient Engagement Advisory Committee (the Committee). The general function of the committee is to provide advice to the Commissioner of Food and Drugs, or designee, on complex scientific issues relating to medical devices, the regulation of devices, and their use by patients. The meeting will be open to the public.

DATES: The meeting will take place virtually on September 6, 2023, from 10 a.m. to 5:20 p.m. Eastern Time.

ADDRESSES: All meeting participants will be heard, viewed, captioned, and recorded for this advisory committee meeting via an online teleconferencing and/or video conferencing platform. Answers to commonly asked questions about FDA advisory committee meetings may be accessed at: <https://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm408555.htm>. Information on how to access the webcast will be made available no later than 2 business days prior to the meeting at <https://www.fda.gov/advisory-committees/committees-and-meeting-materials/patient-engagement-advisory-committee>. Select the link for the 2023 Meeting Materials.

FOR FURTHER INFORMATION CONTACT:

Letise Williams, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 5407, Silver Spring,

¹ This draft guidance also addresses certain topics previously addressed in the guidance for industry entitled “Qualifying for Pediatric Exclusivity Under Section 505A of the Federal Food, Drug, and Cosmetic Act.” That guidance was withdrawn August 7, 2013 (78 FR 48175).

MD 20993-0002, letise.williams@fda.hhs.gov, 301-796-8398, or FDA Advisory Committee Information Line, 1-800-741-8138 (301-443-0572 in the Washington, DC area). A notice in the **Federal Register** about last-minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's website at <https://www.fda.gov/advisory-committees> and scroll down to the appropriate advisory committee meeting link or call the advisory committee information line to learn about possible modifications before the meeting.

SUPPLEMENTARY INFORMATION:

Agenda: The meeting presentations will be heard, viewed, captioned, and recorded through an online teleconferencing platform. On September 6, 2023, the Committee will discuss and make recommendations on the topic of "Advancing Health Equity in Medical Devices." FDA CDRH is committed to working toward ensuring that all patients have access to high-quality, safe, and effective medical devices. This includes ensuring devices are designed to be safe and effective when used by various populations, are evaluated in the diverse populations for which they are intended, and that patients and consumers have the information they need to make decisions about their health, care and quality of life. Technology, including digital health technology, may help bridge gaps in health equity by extending access and bringing healthcare to patients at home, at work, and in their communities. The recommendations provided by the committee will address considerations for FDA and industry on these topics. The Committee will consider ways to advance access to devices that allow for care outside a hospital or clinical care setting—for example, in the home setting. The Committee will also discuss considerations for improving reach and comprehension of FDA's patient and caregiver communications across diverse demographic groups. Additionally, the Committee will discuss patient-focused considerations for when a device should be evaluated in diverse populations to support marketing authorization.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its website prior to the meeting, the background material will be made publicly available on FDA's

website at the time of the advisory committee meeting, and the background material will be posted on FDA's website after the meeting. Background materials and the link to the online teleconference meeting room will be available at <https://www.fda.gov/advisory-committees/committees-and-meeting-materials/patient-engagement-advisory-committee>. Select the link for the 2023 Meeting Materials. The meeting will include slide presentations with audio components to allow the presentation of materials in a manner that most closely resembles an in-person advisory committee meeting.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person (see **FOR FURTHER INFORMATION CONTACT**) on or before August 10, 2023. Oral presentations from the public will be scheduled on September 6, 2023, between approximately 2:15 p.m. to 3:15 p.m. Eastern Time. Those individuals interested in making formal oral presentations should notify the contact person on or before August 2, 2023. The notification should include a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by August 3, 2023.

For press inquiries, please contact the Office of Media Affairs at fdaoma@fda.hhs.gov or 301-796-4540.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with disabilities. If you require accommodations due to a disability, please contact AnnMarie Williams at Annmarie.Williams@fda.hhs.gov, or 240-507-6496 at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our website at <https://www.fda.gov/advisory-committees/about-advisory-committees/public-conduct-during-fda-advisory-committee-meetings> for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: May 15, 2023.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2023-10609 Filed 5-17-23; 8:45 am]

BILLING CODE 4164-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Meeting of the National Vaccine Advisory Committee

AGENCY: Office of Infectious Disease and HIV/AIDS Policy, Office of the Assistant Secretary for Health, Office of the Secretary, Department of Health and Human Services.

ACTION: Notice.

SUMMARY: As stipulated by the Federal Advisory Committee Act, the Department of Health and Human Services (HHS) is hereby giving notice that the National Vaccine Advisory Committee (NVAC) will hold an in-person meeting. The meeting will be open to the public and public comment will be heard during the meeting.

DATES: The meeting will be held June 15–16, 2023. The confirmed meeting times and agenda will be posted on the NVAC website at <http://www.hhs.gov/nvpo/nvac/meetings/index.html> as soon as they become available.

ADDRESSES: Instructions regarding attending this meeting will be posted online at: <http://www.hhs.gov/nvpo/nvac/meetings/index.html> at least one week prior to the meeting. Pre-registration is required for those who wish to attend the meeting virtually or participate in public comment. Please register at <http://www.hhs.gov/nvpo/nvac/meetings/index.html>.

FOR FURTHER INFORMATION CONTACT: Ann Aikin, Acting Designated Federal Officer, Office of Infectious Disease and HIV/AIDS Policy, U.S. Department of Health and Human Services, Tower Building, Room, 1101 Wootton Parkway, Rockville, MD 20852. Email: nvac@hhs.gov. Phone: 202-795-7697.

SUPPLEMENTARY INFORMATION: Pursuant to section 2101 of the Public Health Service Act (42 U.S.C. 300aa-1), the Secretary of HHS was mandated to establish the National Vaccine Program to achieve optimal prevention of human infectious diseases through immunization and to achieve optimal prevention against adverse reactions to vaccines. The NVAC was established to provide advice and make recommendations to the Director of the

National Vaccine Program on matters related to the Program's responsibilities. The Assistant Secretary for Health serves as Director of the National Vaccine Program.

During this meeting, NVAC will hear presentations to support the recent charges on innovation and safety from Admiral Rachel L. Levine, MD, the Assistant Secretary for Health and Director of the National Vaccine Program. NVAC will also hear presentations on vaccine safety, antimicrobial resistance, pandemic preparedness, and routine immunization. Please note that agenda items are subject to change, as priorities dictate. Information on the final meeting agenda will be posted prior to the meeting on the NVAC website: <http://www.hhs.gov/nvpo/nvac/index.html>.

Members of the public will have the opportunity to provide comment at the NVAC meeting during the public comment period designated on the agenda. Public comments made during the meeting will be limited to three minutes per person to ensure time is allotted for all those wishing to speak. Individuals are welcome to submit written comments in advance. Written comments should not exceed three pages in length. Individuals submitting comments should email their written comments or their request to provide a comment during the meeting to nvac@hhs.gov at least five business days prior to the meeting.

Dated: May 10, 2023.

Ann Aikin,

Acting Designated Federal Official, Office of the Assistant Secretary for Health.

[FR Doc. 2023-10635 Filed 5-17-23; 8:45 am]

BILLING CODE 4150-44-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Alcohol Abuse and Alcoholism; Notice of Closed Meeting

Pursuant to section 1009 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 on Alcohol Abuse and Alcoholism Special Emphasis Panel; NIAAA Member Conflict Applications.

Date: June 14, 2023.

Time: 1:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Health, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Beata Buzas, Ph.D., Scientific Review Officer, Extramural Project Review Branch, Office of Extramural Activities, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Room 2116, MSC 6902, Bethesda, MD 20892, (301) 443-0800, bbuzas@mail.nih.gov. (Catalogue of Federal Domestic Assistance Program Nos. 93.273, Alcohol Research Programs, National Institutes of Health, HHS)

Dated: May 15, 2023.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023-10655 Filed 5-17-23; 8:45 am]

BILLING CODE 4140-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 1009 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 Allergy and Infectious Diseases Special Emphasis Panel; NIAID Investigator Initiated Program Project Applications (P01 Clinical Trial Not Allowed).

Date: June 14, 2023.

Time: 11:00 a.m. to 2:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3F52, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Lindsey M. Pujanandez, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3F52, Rockville, MD 20852, (240) 627-3206, lindsey.pujanandez@nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: May 12, 2023.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023-10615 Filed 5-17-23; 8:45 am]

BILLING CODE 4140-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Notice of Closed Meetings

Pursuant to section 1009 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: Center for Scientific Review Special Emphasis Panel; Mechanisms of Cancer Therapeutics C.

Date: June 15-16, 2023.

Time: 8:00 a.m. to 8:00 p.m.

Agenda: To review and evaluate grant applications.

Place: The Watergate, 2650 Virginia Avenue NW, Washington, DC 20037.

Contact Person: Gloria Huei-Ting Su, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, 301-496-0465, gloria.su@nih.gov.

Name of Committee: Brain Disorders and Clinical Neuroscience Integrated Review Group; Neural Basis of Psychopathology, Addictions and Sleep Disorders Study Section.

Date: June 15-16, 2023.

Time: 9:00 a.m. to 7:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Salma Asmat Quraishi, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, (301) 594-0592, salma.quraishi@nih.gov.

Name of Committee: Cardiovascular and Respiratory Sciences Integrated Review Group; Clinical Integrative Cardiovascular and Hematological Sciences Study Section.

Date: June 15–16, 2023.

Time: 9:00 a.m. to 7:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Margaret Chandler, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4126, MSC 7814, Bethesda, MD 20892, (301) 435-1743, margaret.chandler@nih.gov.

Name of Committee: Biobehavioral and Behavioral Processes Integrated Review Group; Human Complex Mental Function Study Section.

Date: June 15–16, 2023.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Joanna Szczepanik, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 1000D, Bethesda, MD 20892, (301) 827-2242, szczepaj@csr.nih.gov.

Name of Committee: Population Sciences and Epidemiology Integrated Review Group; Lifestyle and Health Behaviors Study Section.

Date: June 15–16, 2023.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Lisa T. Wigfall, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 1007G, Bethesda, MD 20892, (301) 594-5622, wigfallt@mail.nih.gov.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Training in Veterinary and Comparative Medicine.

Date: June 16, 2023.

Time: 9:30 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Raj K. Krishnaraju, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6190, MSC 7804, Bethesda, MD 20892, (301) 435-1047, krishna@csr.nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine;

93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: May 15, 2023.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023-10650 Filed 5-17-23; 8:45 am]

BILLING CODE 4140-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 1009 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 Allergy and Infectious Diseases Special Emphasis Panel; Development of Radiation/Nuclear Medical Countermeasures (MCMs) and Biodosimetry Devices.

Date: June 13, 2023.

Time: 8:30 a.m. to 6:00 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 5G22, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Michael M. Opat, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 5G22, Rockville, MD 20852, 240-627-3319, michael.opata@nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: May 12, 2023.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023-10613 Filed 5-17-23; 8:45 am]

BILLING CODE 4140-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; Notice of Closed Meetings

Pursuant to section 1009 of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

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/or 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 grant applications and/or contract proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; HEAL Initiative: Rapidly Assessing the Public Health Impact of Emerging Opioid Threats (UG1).

Date: June 16, 2023.

Time: 3:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate cooperative agreement applications.

Place: National Institute of Health, National Institute on Drug Abuse, 301 North Stonestreet Avenue, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Gerald L. McLaughlin, Ph.D., Scientific Review Officer, Office of Extramural Policy and Review, National Institute on Drug Abuse, NIH, 301 North Stonestreet Avenue, MSC 6021, Bethesda, MD 20892, (301) 827-5819, gm145a@nih.gov.

Name of Committee: National Institute on Drug Abuse Special Emphasis Panel; Toxicological Evaluations of Potential Medication.

Date: June 29, 2023.

Time: 11:00 a.m. to 1:00 p.m.

Agenda: To review and evaluate contract proposals.

Place: National Institute of Health, National Institute on Drug Abuse, 301 North Stonestreet Avenue, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Brian Stefan Wolff, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, National Institute on Drug Abuse, NIH, 301 North Stonestreet Avenue, MSC 6021, Rockville, MD 20852, (301) 480-1448, brian.wolff@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: May 12, 2023.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023–10614 Filed 5–17–23; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to section 1009 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 Allergy and Infectious Diseases Special Emphasis Panel; NIAID Investigator Initiated Program Project Applications (P01 Clinical Trial Not Allowed).

Date: June 13, 2023.

Time: 12:00 p.m. to 3:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3F52, Rockville, MD 20892 (Virtual Meeting).

Contact Person: Lindsey M. Pujanandez, Ph.D., Scientific Review Officer, Scientific Review Program, Division of Extramural Activities, National Institute of Allergy and Infectious Diseases, National Institutes of Health, 5601 Fishers Lane, Room 3F52, Rockville, MD 20852, (240) 627–3206, lindsey.pujanandez@nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.855, Allergy, Immunology, and Transplantation Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health, HHS)

Dated: May 12, 2023.

Tyeshia M. Roberson-Curtis,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023–10616 Filed 5–17–23; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Amended Notice of Meeting

Notice is hereby given of a change in the meeting of the Center for Scientific Review Special Emphasis Panel, May 26, 2023, 10:00 a.m. to 2:00 p.m., National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892, which was published in the **Federal Register** on May 3, 2023, FR Doc. No. 2023–09379, 88 FR 27918.

This notice is being amended to change the Panel Name of the meeting from Center for Scientific Review Special Emphasis Panel to Center for Scientific Review Special Emphasis Panel PAR–22–233: Time-Sensitive Opportunities for Health Research. The meeting is closed to the public.

Dated: May 15, 2023.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023–10648 Filed 5–17–23; 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 Closed Meetings

Pursuant to section 1009 of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

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 Human Genome Research Institute Special Emphasis Panel; Genomic Community Resources.

Date: June 7, 2023.

Time: 1:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Room 3189, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Keith McKenney, Ph.D., Scientific Review Officer, National Human

Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Suite 3000, Bethesda, MD 20892, (301) 594–4280, mckenneyk@mail.nih.gov.

Name of Committee: National Human Genome Research Institute Special Emphasis Panel; Nucleic Acid Sequencing Technology.

Date: June 16, 2023.

Time: 1:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Room 3189, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Keith McKenney, Ph.D., Scientific Review Officer, National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Suite 3000, Bethesda, MD 20892, (301) 594–4280, mckenneyk@mail.nih.gov.

Name of Committee: National Human Genome Research Institute Special Emphasis Panel; Early Career and Workforce Diversity in Genomics.

Date: June 20, 2023.

Time: 12:00 p.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Human Genome Research Institute, National Institutes of Health, 6700B Rockledge Drive, Room 3189, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Sarah Jo Wheelan, Ph.D., Scientific Review Officer, Scientific Review Branch, National Institute for Human Genome Research, National Institutes of Health, 6700B Rockledge Drive, Room 3180, Bethesda, MD 20892, (301) 402–8823, wheelansj@nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.172, Human Genome Research, National Institutes of Health, HHS)

Dated: May 15, 2023.

Melanie J. Pantoja,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2023–10646 Filed 5–17–23; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Heart, Lung, and Blood Institute; Amended Notice of Meeting

Notice is hereby given of a change in the meeting of the National Heart, Lung, and Blood Advisory Council, June 6, 2023, 9:00 a.m. to June 6, 2023, 5:00 p.m., National Institutes of Health, Rockledge I, 6705 Rockledge Drive, Bethesda, MD 20892 which was published in the **Federal Register** on May 09, 2023, FR Document No. 2023–09862, 88 FRN 29914.

This notice is being amended to correct the time for the National Heart, Lung, and Blood Advisory Council closed session on June 6, 2023, that was

previously published as 9:00 a.m. to 10:00 p.m. The correct time is from 9:00 a.m. to 10:00 a.m. The meeting is partially closed to the public.

Dated: May 15, 2023.

Melanie J. Pantoja,
Program Analyst, Office of Federal Advisory
Committee Policy.

[FR Doc. 2023-10649 Filed 5-17-23; 8:45 am]

BILLING CODE 4140-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Substance Abuse and Mental Health Services Administration

Fiscal Year (FY) 2023 Notice of Supplemental Funding Opportunity

AGENCY: Substance Abuse and Mental Health Services Administration, Department of Health and Human Services (HHS).

ACTION: Notice of intent to award supplemental funding.

SUMMARY: This notice is to inform the public that the Substance Abuse and Mental Health Services Administration (SAMHSA) is supporting a supplement in scope of the original award for the one grant recipient, the Community Anti-Drug Coalitions of America (CADCA), funded in FY 2019 under the National Anti-Drug Coalitions Training and Workforce Development award, Notice of Funding Opportunity (NOFO) SP-19-002. The recipient may receive up to \$175,000 and the project period will be extended by 12 months until November 30, 2024. The supplemental funding to CADCA will be used to continue the Voices of Youth Training Initiative. The Voices of Youth Training Initiative has shown positive results, and the continuation of the program will support finalizing the sustainability and scalability beyond the supplements. The supplement will continue to connect the Future Health Professionals (HOSA) national student organization with CADCA to support youth-led strategic planning for the prevention field and develop leadership skills for the future workforce. This supplement will also allow CADCA to provide HOSA students an opportunity to both learn about and provide valuable input into strategic initiatives for prevention.

FOR FURTHER INFORMATION CONTACT: David Wilson, Substance Abuse and Mental Health Services Administration, 5600 Fishers Lane, Rockville, MD 20857, telephone (240) 276-2558; email: david.wilson@samhsa.hhs.gov.

SUPPLEMENTARY INFORMATION:

Funding Opportunity Title: FY 2019 National Anti-Drug Coalitions Training and Workforce Development Grant SP-19-002.

Assistance Listing Number: 93.243.

Authority: Section 516 of the Public Health Services Act, as amended.

Justification: The purpose of the National Anti-Drug Coalitions Training and Workforce Development grant program is to provide education, training, and technical assistance for coalition leaders and community teams, with an emphasis on the development of coalitions serving economically disadvantaged areas. The program disseminates evaluation tools, mechanisms, and measures to better assess and document coalition performance measures and outcomes and bridge the gap between research and practice by translating knowledge from research into practical application. Eligibility for this supplemental funding is limited to the FY 2019 National Anti-Drug Coalitions Training and Workforce Development recipient, CADCA. CADCA has special expertise providing training and workforce development for thousands of members of community coalitions dedicated to preventing substance use. This organization is uniquely positioned to train youth in community-focused prevention activities being funded through this supplement.

This is not a formal request for application. Assistance will only be provided to the National Anti-Drug Coalitions Training and Workforce Development grant recipient funded in FY 2019 under the National Anti-Drug Coalitions Training and Workforce Development Cooperative Agreement SP-19-002 based on the receipt of a satisfactory application and associated budget that is approved by a review group.

Dated: May 15, 2023.

Ann Ferrero,

Public Health Analyst.

[FR Doc. 2023-10632 Filed 5-17-23; 8:45 am]

BILLING CODE 4162-20-P

DEPARTMENT OF HOMELAND SECURITY

U.S. Citizenship and Immigration Services

[OMB Control Number 1615-0014]

Agency Information Collection Activities; Extension, Without Change, of a Currently Approved Collection: Declaration of Financial Support

AGENCY: U.S. Citizenship and Immigration Services, Department of Homeland Security.

ACTION: 30-Day notice.

SUMMARY: The Department of Homeland Security (DHS), U.S. Citizenship and Immigration Services (USCIS) will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995. The purpose of this notice is to allow an additional 30 days for public comments.

DATES: Comments are encouraged and will be accepted until June 20, 2023.

ADDRESSES: Written comments and/or suggestions regarding the item(s) contained in this notice, especially regarding the estimated public burden and associated response time, must be submitted via the Federal eRulemaking Portal website at <http://www.regulations.gov> under e-Docket ID number USCIS-2006-0072. All submissions received must include the OMB Control Number 1615-0014 in the body of the letter, the agency name and Docket ID USCIS-2006-0072.

FOR FURTHER INFORMATION CONTACT: USCIS, Office of Policy and Strategy, Regulatory Coordination Division, Samantha Deshommes, Chief, telephone number (240) 721-3000 (This is not a toll-free number; comments are not accepted via telephone message.). Please note contact information provided here is solely for questions regarding this notice. It is not for individual case status inquiries. Applicants seeking information about the status of their individual cases can check Case Status Online, available at the USCIS website at <http://www.uscis.gov>, or call the USCIS Contact Center at 800-375-5283 (TTY 800-767-1833).

SUPPLEMENTARY INFORMATION:

Comments

The information collection notice was previously published in the **Federal Register** on March 09, 2023, at 88 FR 14633, allowing for a 60-day public comment period. USCIS did receive one

comment in connection with the 60-day notice.

You may access the information collection instrument with instructions, or additional information by visiting the Federal eRulemaking Portal site at: <http://www.regulations.gov> and enter USCIS-2006-0072 in the search box. The comments submitted to USCIS via this method are visible to the Office of Management and Budget and comply with the requirements of 5 CFR 1320.12(c). All submissions will be posted, without change, to the Federal eRulemaking Portal at <http://www.regulations.gov>, and will include any personal information you provide. Therefore, submitting this information makes it public. You may wish to consider limiting the amount of personal information that you provide in any voluntary submission you make to DHS. DHS may withhold information provided in comments from public viewing that it determines may impact the privacy of an individual or is offensive. For additional information, please read the Privacy Act notice that is available via the link in the footer of <http://www.regulations.gov>.

Written comments and suggestions from the public and affected agencies should address one or more of the following four points:

(1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) 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 responses.

Overview of This Information Collection

(1) *Type of Information Collection Request*: Extension, without change, of a currently approved collection.

(2) *Title of the Form/Collection*: Declaration of Financial Support.

(3) *Agency form number, if any, and the applicable component of the DHS sponsoring the collection*: I-134; USCIS.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract*: **Primary**: Individuals or households. U.S. Citizenship and Immigration Services (USCIS) and consular officers of the Department of State (DOS) use Form I-134 to determine whether, at the time of the beneficiary's application, petition, or request for certain immigration benefits, that the beneficiary has sufficient financial support to pay for expenses for the duration of their temporary stay in the United States.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond*: The estimated total number of respondents for the information collection I-134 is 2,500 and the estimated hour burden per response is 2 hours.

(6) *An estimate of the total public burden (in hours) associated with the collection*: The total estimated annual hour burden associated with this collection is 5,000 hours.

(7) *An estimate of the total public burden (in cost) associated with the collection*: The estimated total annual cost burden associated with this collection of information is \$10,625.

Dated: May 12, 2023.

Samantha L. Deshommes,

Chief, Regulatory Coordination Division, Office of Policy and Strategy, U.S. Citizenship and Immigration Services, Department of Homeland Security.

[FR Doc. 2023-10595 Filed 5-17-23; 8:45 am]

BILLING CODE 9111-97-P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

DEPARTMENT OF AGRICULTURE

[Docket No. FR-6271-N-01]

RIN 2506-AC55

Adoption of Energy Efficiency Standards for New Construction of HUD- and USDA-Financed Housing: Preliminary Determination and Solicitation of Comment

AGENCY: Department of Housing and Urban Development, Department of Agriculture.

ACTION: Notice of preliminary determination.

SUMMARY: The Energy Independence and Security Act of 2007 (EISA) establishes procedures for the U.S. Department of Housing and Urban Development (HUD) and the U.S. Department of Agriculture (USDA) to adopt periodic revisions to the

International Energy Conservation Code (IECC) and to ANSI/ASHRAE/IES Standard 90.1: Energy Standard for Buildings, Except Low-Rise Residential Buildings (ASHRAE 90.1), subject to a determination by HUD and USDA that the revised codes do not negatively affect the availability or affordability of new construction of single and multifamily housing covered by EISA, and a determination by the Secretary of Energy that the revised codes "would improve energy efficiency." This Notice announces the preliminary determination of HUD and USDA, as required under section 481(d)(1) of EISA, that the 2021 IECC and ASHRAE 90.1-2019 will not negatively affect the affordability and availability of housing covered by EISA. In making this preliminary determination, the first step to ultimately requiring compliance with these standards in HUD and USDA housing covered by EISA, this Notice relies on several studies that show that these codes are cost effective in that the incremental cost of the additional efficiency measures pays for themselves with energy cost savings on a life-cycle basis.

DATES: *Comment Due Date*: July 17, 2023.

ADDRESSES: Interested persons are invited to submit comments regarding this Notice. There are two methods for submitting public comments, listed below. All submissions must refer to the above-referenced docket number (FR-6271-N-01) and title of this Notice.

Electronic Submission of Comments. Interested persons may submit comments electronically through the Federal eRulemaking Portal at www.regulations.gov. HUD and USDA strongly encourage commenters to submit comments electronically. Electronic submission of comments allows the commenter maximum time to prepare and submit a comment, ensures timely receipt, and enables HUD and USDA to make them immediately available to the public. Comments submitted electronically through the www.regulations.gov website can be viewed by other commenters and interested members of the public. Commenters should follow the instructions provided on that site to submit comments electronically.

Submission of Comments by Mail. Comments may be submitted by mail to the Regulations Division, Office of General Counsel, Department of Housing and Urban Development, 451 7th Street SW, Room 10276, Washington, DC 20410-0500.

Note: To receive consideration as public comments, comments must be submitted

through one of the two methods specified above. Again, all submissions must refer to the docket number and title of this Notice.

No Facsimile Comments. Facsimile comments are not acceptable.

Public Inspection of Public Comments. All properly submitted comments and communications submitted to HUD will be available for public inspection and copying between 8 a.m. and 5 p.m., weekdays, at the above address. Due to security measures at the HUD Headquarters building, an appointment to review the public comments must be scheduled in advance by calling the Regulations Division at 202-708-3055 (this is not a toll-free number). HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech or communication disabilities. To learn more about how to make an accessible telephone call, please visit www.fcc.gov/consumers/guides/telecommunications-relay-service-trs.

FOR FURTHER INFORMATION CONTACT:

HUD: Michael Freedberg, Office of Environment and Energy, Department of Housing and Urban Development, 451 7th Street SW, Room 7282, Washington, DC 20410; telephone number 202-402-4366 (this is not a toll-free number).
USDA: Meghan Walsh, Rural Housing Service, Department of Agriculture, 1400 Independence Avenue SW, Washington, DC 20250; telephone number (202) 573-3692 (this is not a toll-free number). HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech or communication disabilities. To learn more about how to make an accessible telephone call, please visit www.fcc.gov/consumers/guides/telecommunications-relay-service-trs.

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I. Introduction

Statutory Requirements

Section 481 of the Energy Independence and Security Act of 2007 (“EISA,” Pub. L. 110–140) amended section 109 of the Cranston-Gonzalez National Affordable Housing Act of 1990 (Cranston-Gonzalez) (42 U.S.C. 12709), which establishes procedures for setting minimum energy standards for the following three categories of housing financed or assisted by HUD and USDA:

(A) New construction of public and assisted housing and single-family and multifamily residential housing (other than manufactured homes) subject to mortgages insured under the National Housing Act;¹

(B) New construction of single-family housing (other than manufactured homes) subject to mortgages insured, guaranteed, or made by the Secretary of Agriculture under title V of the Housing Act of 1949;² and,

(C) Rehabilitation and new construction of public and assisted housing funded by HOPE VI revitalization grants under section 24 of the United States Housing Act of 1937 (42 U.S.C. 1437v).

In addition to these EISA-specified categories, other HUD programs apply EISA to new construction projects through their program statutes and regulations, including the HOME Investment Partnerships Program (HOME) and the Housing Trust Fund. Sections 215(a)(1)(F) and (b)(4) of Cranston-Gonzalez (42 U.S.C. 12745(a)(1)(F) and (b)(4)) make new construction of rental housing and homeownership housing assisted under the HOME program subject to section 109 of Cranston-Gonzalez (42 U.S.C. 12709) and, therefore, to section 481 of EISA. From the beginning of the HOME program, the regulation at 24 CFR 92.251 implemented section 109 of Cranston-Gonzalez (42 U.S.C. 12709). However, compliance with section 109 of Cranston-Gonzalez (42 U.S.C. 12709) was omitted from the July 2013 HOME program final rule because HUD planned to update and implement energy efficiency standards through a separate proposed rule (see the discussion in the preamble to the HOME proposed rule published on December

¹ This subsection of EISA refers to HUD programs. See Table 1 for specific HUD programs covered by the Act.

² This subsection of EISA refers to USDA programs. See Table 1 for specific USDA programs covered by the Act.

16, 2011 (76 FR 78344)). Although the energy standards at 24 CFR 92.251(a)(2)(ii) are reserved in the July 2013 HOME final program rule, the statutory requirements of section 109 of Cranston-Gonzalez (42 U.S.C. 12709) continue to apply to all newly-constructed housing funded by the HOME program.

With regard to the Housing Trust Fund, program regulations at 24 CFR 93.301(a)(2)(ii) Property Standards, require compliance with the minimum standards required under Cranston-Gonzalez section 109 (42 U.S.C. 12709).

EISA references two standards: the International Energy Conservation Code (IECC) and ANSI/ASHRAE/IES Standard 90.1.³ The IECC standard applies to single-family homes and multifamily low-rise buildings (up to 3 stories), while the ASHRAE 90.1 standard applies to multifamily residential buildings with 4 or more stories.⁴ For both agencies, applicability is limited to newly constructed housing and does not include the purchase or repair of existing housing.⁵

Sections 109(c) and (d) of Cranston-Gonzalez, as amended by EISA, establish procedures for updating HUD and USDA energy standards following

periodic revisions to the IECC and ASHRAE 90.1 codes, typically every three years. Specifically, section 109(d) of Cranston-Gonzalez (42 U.S.C. 12709) provides that revisions to the IECC or ASHRAE codes will apply to the three categories of housing financed or assisted by HUD or USDA described above if: (1) either agency “make(s) a determination that the revised codes do not negatively affect the availability or affordability” of such housing, and (2) the Secretary of Energy has made a determination under section 304 of the Energy Conservation and Production Act (42 U.S.C. 6833) that the revised codes would improve energy efficiency (42 U.S.C. 12709(d)). The Department of Energy (DOE) has published Final Determinations that the 2021 IECC and ASHRAE 90.1–2019 standards would improve energy efficiency (86 FR 40529; July 28, 2021, and 86 FR 40543; July 28, 2021).

Note that DOE issued a separate final rule under EISA section 413 that establishes energy conservation standards for manufactured housing (42 U.S.C. 17071).⁶ Those standards are based on the 2021 version of the International Energy Conservation Code

(“IECC”) and feedback received during interagency consultation with HUD.

Energy Codes Overview

There are two primary benefits of adopting energy-saving building codes: a private benefit for residents—either homeowners or renters—in the form of lower energy costs, and the external social value of reducing the emission of greenhouse gases (GHGs). Additional benefits may include improved health and resilience against extreme hot or cold weather events. As discussed in more detail below, states or localities typically adopt the IECC and ASHRAE standards on a voluntary basis one or more years after their publication. DOE has determined that the 2021 IECC represents an approximately 40 percent improvement in energy efficiency for residential and commercial buildings compared to the 2006 edition. The 2021 IECC also for the first time includes a Zero Energy Appendix. The Appendix is an optional add-on to the 2021 IECC that—if adopted by a state or local jurisdiction—will result in residential buildings having net zero energy consumption over the course of a year. The current state adoption of the IECC and ASHRAE standards is as follows:

DISTRIBUTION OF STATE ADOPTION OF IECC AND ASHRAE 90.1 STANDARDS

IECC * single family and low-rise multifamily		ASHRAE 90.1 * mid-rise and high-rise multifamily	
Year	Number of states	Year	Number of states
IECC 2021	3	ASHRAE 90.1–2019	6
IECC 2018	9	ASHRAE 90.1–2016	2
IECC 2015	2	ASHRAE 90.1–2013	19
IECC 2012	0	ASHRAE 90.1–2010	6
IECC 2009	26	ASHRAE 90.1–2007	8
Less stringent than IECC 2009, No Statewide Code or Home Rule.	11	Less stringent than ASHRAE 90.1–2007, No Statewide Code or Home Rule.	10

* As of September 2022.

Covered HUD and USDA Programs

Table 1 lists the specific HUD and USDA programs covered by EISA, with

certain exclusions noted, as discussed below. Apart from the HOPE VI program, where rehabilitation is

referenced, only new construction of housing financed or assisted under these programs is covered by EISA.

TABLE 1—COVERED HUD AND USDA PROGRAMS

HUD programs	Legal authority	Regulations or notices
Public Housing Capital Fund	Section 9(d) and Section 30 of the U.S. Housing Act of 1937 (42 U.S.C. 1437g(d) and 1437z–2).	24 CFR parts 905.
Capital Fund Financing Program	Section 9(d) and Section 30 of the U.S. Housing Act of 1937 (42 U.S.C. 1437g(d) and 1437z–2).	24 CFR part 905 subpart E.

³ ANSI—American national Standards Institute; ASHRAE—American Society of Heating, Refrigerating, and Air-Conditioning Engineers; IES—Illuminating Electrical Society.

⁴ Note the IECC addresses both residential and commercial buildings. ASHRAE 90.1 covers

commercial buildings only, including multifamily buildings four or more stories above grade. IECC Section C 401.2 adopts, by reference, ASHRAE 90.1; that is, compliance with ASHRAE 90.1 qualifies as compliance with the IECC for commercial buildings.

⁵ The statute covers rehabilitation as well as new construction of housing assisted by HOPE VI revitalization grants; however, as noted below, the HOPE VI program is no longer funded.

⁶ 87 FR 32728 (May 31, 2022); 10 CFR part 460.

TABLE 1—COVERED HUD AND USDA PROGRAMS—Continued

HUD programs	Legal authority	Regulations or notices
* HOPE VI Revitalization of Severely Distressed Public Housing. Choice Neighborhoods Implementation Grants.	Section 24 of the U.S. Housing Act of 1937 (42 U.S.C. 1437v)	FR-5415-N-07.
Section 202 Supportive Housing for the Elderly.	Section 24 of the U.S. Housing Act of 1937 (42 U.S.C. 1437v)	FR-5800-N-11.
Section 811 Supportive Housing for Persons with Disabilities.	Section 202 of the Housing Act of 1959 (12 U.S.C. 1701q), as amended.	24 CFR part 891.
Rental Assistance Demonstration (RAD).	Section 811 of the Cranston-Gonzalez National Affordable Housing Act (42 U.S.C. 8013) as amended.	24 CFR part 891.
FHA Single-family Mortgage Insurance Programs.	Consolidated and Further Continuing Appropriations Act of 2012 (Pub. L. 112-55), as amended by Consolidated Appropriations Act, 2014 (Pub. L. 113-76) and subsequent Consolidated Appropriations Acts.	RAD Notice Revision 4 (H 2019-09 PIH 2019-23).
FHA Multifamily Mortgage Insurance Programs.	National Housing Act, Sections 203(b) (12 U.S.C. 1709(b)), Section 251 (12 U.S.C. 1715z-16), Section 247 (12 U.S.C. 1715z-12), Section 203(h) (12 U.S.C. 1709(h)), Housing and Economic Recovery Act of 2008 (Pub. L. 110-289), Section 248 of the National Housing Act (12 U.S.C. 1715z-13).	24 CFR part 203, subpart A; 203.18(i); 203.43i; 203.49; 203.43h.
HOME Investment Partnerships (HOME).	Sections 213, 220, 221, 231, and 232 of the National Housing Act (12 U.S.C. 1715e, 12 U.S.C. 1715v, 12 U.S.C. 1715k, 12 U.S.C. 1715l, 12 U.S.C. 1715w).	24 CFR parts 200, subpart A, 213; 220; 221, subparts C and D; 231; and 232.
Housing Trust Fund [By regulation]	Cranston-Gonzalez sections 215(b)(4) and 215(a)(1)(F) (42 U.S.C. 12745(b)(4) and 42 U.S.C. 12745(a)(1)(F)) require HOME units to meet minimum energy efficiency standards promulgated by the Secretary in accordance with Cranston Gonzalez section 109 (42 U.S.C. 12745).	Final HOME Rule at www.onecpd.info/home/home-final-rule/ reserves the energy standard for a separate rule-making at 24 CFR 92.251.
	Title I of the Housing and Economic Recovery Act of 2008, Section 1131 (Pub. L. 110-289, 12 U.S.C. 4568.).	24 CFR 93.301(a)(2)(ii) Property Standards, requires compliance with Cranston Gonzalez section 109 (42 U.S.C. 12709).
USDA Programs		
Section 502 Guaranteed Housing Loans.	Section 502 of Housing Act (42 U.S.C. 1472)	7 CFR part 3550.
Section 502 Rural Housing Direct Loans.	Section 502 of Housing Act (42 U.S.C. 1472)	7 CFR part 3550.
Section 523 Mutual Self Help Technical Assistance Grants , homeowner participants.	Section 523 of Housing Act (42 U.S.C. 1472)	7 CFR part 1944 subpart-I.

* Program no longer funded or no longer funds new construction.

Several exclusions are worth noting. These include the following programs which, while classified as public or assisted housing, or may be specified in the statute, are no longer funded, or do not fund new construction:

(1) *HOPE VI*. While EISA references the “rehabilitation and new construction of public and assisted housing funded by HOPE VI revitalization grants,” funding for HOPE VI revitalization grants has been discontinued, so the program is therefore not covered by this Notice.

(2) *Project-Based Rental Assistance (PBRA)*. HUD is no longer authorized to provide funding for new construction of units assisted under the Section 8 PBRA program, except under the Rental Assistance Demonstration (RAD). Apart from RAD, current authorization and funding that Congress provides for the PBRA program is for the limited purpose of renewing expiring Section 8 rental-assistance contracts. Accordingly,

this Notice does not apply to the Section 8 PBRA program except through RAD, as referenced in Table 1.

Other HUD programs that provide financing for new construction are not covered because they do not constitute assisted housing as specified in EISA and/or are authorized under statutes not specifically referenced in EISA:

(1) *Indian Housing*. Indian housing programs are excluded because they do not constitute assisted housing and are not authorized under the National Housing Act (12 U.S.C. 1701 *et seq.*) as specified in EISA. For example, the Section 184 guaranteed loan program is authorized under Section 184 of the Housing and Community Development Act of 1992 (42 U.S.C. 1715z-13a).

(2) *Community Development Block Grants*. Housing financed with Community Development Block Grant (CDBG) funds is excluded since CDBG, which is authorized by the Housing and Community Development Act of 1974

(42 U.S.C. 5301 *et seq.*), is neither an assisted housing program nor a National Housing Act mortgage insurance program.

Current Above-Code Standards or Incentives

Some HUD and USDA competitive grant programs covered by EISA (as well as other programs) already require grantees to comply with energy efficiency standards or green building requirements with energy performance requirements that exceed state or locally-adopted IECC and ASHRAE 90.1 standards, while other programs provide incentives to do so. A list of current programs that require or incentivize a green building standard is shown in Table 2. This standard is typically Energy Star Certified New Homes for single-family properties, Energy Star for Multifamily New Construction, or a green building standard recognized by HUD that includes a minimum energy

efficiency requirement. Nothing in this Notice will preclude HUD or USDA competitive programs from maintaining these higher standards or raising them further, or for HUD or USDA programs to provide incentives for above-code energy requirements.

Table 2 includes a listing of current HUD and USDA programs with requirements or incentives for funding recipients to build to standards above the current 2009 IECC and/or ASHRAE 90.1 standards (see “Already Exceeds Current Energy Standard” column).

Contingent on the energy efficiency or green building standard selected, and the minimum energy efficiency requirements established for each standard, projects built to these above-code standards may also exceed the proposed 2021 IECC and ASHRAE 90.1–2019 standards discussed in this Notice (see “Meets or Exceeds Proposed Energy Standard” column). HUD and USDA are requesting comments in this Notice on the current energy efficiency requirements included in the green building standards incentivized or

required by these programs. (See Section V. Implementation, Alternate Compliance Pathways, and Section VI, Request for Public Comment, Question 8). These green building or energy performance typically have multiple certification levels with varying energy baselines and these baselines change over time at varying points after publication of newer editions of the energy codes. HUD and USDA will seek certifications from the standard-setting bodies that each of these programs meet the requirements of this Notice.

TABLE 2—CURRENT ENERGY STANDARDS AND INCENTIVES FOR HUD AND USDA PROGRAMS

[New construction]⁷

Program	Type	Current energy efficiency requirements and incentives	Exceeds current energy standards	Already meets or exceeds proposed energy standards
Programs Covered by EISA				
HUD:				
Choice Neighborhoods Implementation.	Competitive Grant	<i>Required:</i> Requirements of Energy Star Single Family New Homes or Multifamily New Construction. Plus certification by recognized green rating such as Energy Star Indoor Air Plus, Enterprise Green Communities, National Green Building Standard, LEED–H, LEED–NC, or regional standards such as Earthcraft or Built Green. Use Energy Star products.	Exceeds 2009 IECC/ASHRAE 90.1–2007.	May meet or exceed proposed 2021 IECC/ASHRAE 90.1–2019 standard.
Choice Neighborhoods—Planning.	Competitive Grant	<i>Required:</i> Eligible for Stage 1 Conditional Approval LEED for Neighborhood Development (LEED–ND) or equivalent. Plus certification by recognized green rating program.	Exceeds 2009 IECC/ASHRAE 90.1–2007.	May meet or exceed proposed 2021 IECC/ASHRAE 90.1–2019 standard.
Section 202 Supportive Housing for the Elderly.	Competitive Grant	<i>Required:</i> 2021 IECC and ASHRAE 90.1–2019. <i>Incentive:</i> Additional competitive rating points for developments that meet a green building or energy performance standard that includes a Zero Energy Ready or Net Zero Energy requirement.	Exceeds 2009 IECC/ASHRAE 90.1–2007.	Meets and may exceed proposed 2021 IECC/ASHRAE 90.1–2019 standard.
Section 811 for Persons with Disabilities.	Competitive Grant	Energy Star Certified New Construction	Exceeds 2009 IECC/ASHRAE 90.1–2007.	
Rental Assistance Demonstration (RAD).	Conversion of Existing Units.	2009 IECC or ASHRAE 90.1–2007 or any successor code adopted by HUD; applicants encouraged to build to Energy Star Certified New Construction. Minimum WaterSense and Energy Star appliances required and the most cost-effective measures identified in the Physical Condition Assessment.		
FHA Multifamily Mortgage Insurance.	Mortgage Insurance.	<i>Incentive:</i> Discounted Mortgage Insurance Premium (MIP) for a recognized Green Building Standard. Energy Star Score of at least 75 in EPA Portfolio Manager.	Incentives exceed 2009 IECC/ASHRAE 90.1–2007.	May meet or exceed proposed 2021 IECC/ASHRAE 90.1–2019 standard.
FHA Single Family Mortgage Insurance.	Mortgage Insurance.	2009 IECC.		
HOME Investment Partnerships Program.	Formula Grant	2009 IECC/ASHRAE 90.1–2007.		
Housing Trust Fund.	Formula Grant	2009 IECC/ASHRAE 90.1–2007.		
Public Housing Capital Fund.	Formula Grant	2009 IECC/ASHRAE 90.1–2010 or successor standards. Energy Star appliances also required unless not cost effective.		
USDA:				
Section 502 Guaranteed Housing Loans.	Loan Guarantee ...	2009 IECC at minimum. Stretch ratio of 2 percent on mortgage qualifications for complying with above-code standards.		

TABLE 2—CURRENT ENERGY STANDARDS AND INCENTIVES FOR HUD AND USDA PROGRAMS—Continued
[New construction]⁷

Program	Type	Current energy efficiency requirements and incentives	Exceeds current energy standards	Already meets or exceeds proposed energy standards
Section 502 Rural Housing Direct Loans.	Direct Loan	2009 IECC at minimum. Stretch ratio of 2 percent on mortgage qualifications for complying with above-code standards.		
Section 523 Mutual Self Help.	Grant Program	2009 IECC at minimum. State adopted versions of more recent codes vary.		
Programs Not Covered by EISA				
HUD CDBG—DR, CDBG—MIT.	Grants to states or localities.	For new construction of substantially damaged buildings, meet a minimum energy standard and green building standard recognized by HUD.	Exceeds 2009 IECC/ASHRAE 90.1–2007 requirements.	May meet or exceed proposed 2021 IECC/ASHRAE 90.1–2019 standard.
USDA Multi-family Sec. 515 New Construction, Sec 514/516 Farmworker Housing, Sec 538 Guaranteed Loans.	Direct Loans, Guaranteed Loans and Grants.	Meet minimum state or local energy codes. Incentive for Secs 514/515/516: Energy Star Certified New Homes, Enterprise Green Communities, NGBS, DOE Zero Energy Ready, LEED, Passive House, Living Building Challenge.	Incentives exceed 2009 IECC/ASHRAE 90.1–2007.	May meet or exceed proposed 2021 IECC/ASHRAE 90.1–2019 standard.

II. 2021 IECC Affordability Determination

A. Overview

The IECC is a model energy code developed by the International Code Council (ICC) through a public hearing process involving national experts for single-family and low-rise residential buildings as well as commercial buildings.⁸ The code contains minimum energy efficiency provisions for residential buildings, defined as single-family homes and low-rise multifamily buildings (up to three stories). The code offers both prescriptive and performance-based approaches. The efficiency standards associated with the IECC set benchmarks for a structure's walls, floors, ceilings, lighting, windows, doors, duct leakage, and air leakage.

Revised editions of the IECC are typically published every three years. Full editions of its predecessor, the Model Energy Code, were first

published in 1989, and new editions of the IECC were published every three years beginning in 1998. The residential portion of the IECC was heavily revised in 2004: the Climate Zones were completely revised (reduced from 17 Zones to the current eight primary Zones) and the building envelope requirements were restructured into a different format.⁹ The post-2004 code became much more concise and simpler to use, but these changes complicate comparisons of State codes based on pre-2004 versions of the IECC to the more recent editions.

For single family housing, the IECC is one component of the larger International Residential Code (IRC). Each version of the IRC, beginning with the 2015 edition, has the corresponding version of the IECC embedded directly into that code (Chapter 11). A majority of states have adopted some version of the IRC. For other building types, including multifamily housing, the equivalent building code is the

International Building Code (IBC), which also refers to other codes such as the International Plumbing Code, the International Electrical Code or, in this case, the IECC. Those codes also then embody or refer to other codes in the industry, such as ASHRAE 90.1. In this hub and spoke model, there is even more differentiation between states regarding which versions of which codes are adopted as a suite of codes at any given point in time. Even with the adoption of the IRC, the all-in-one code that is focused on single-family housing, states and local areas sometimes make adjustments to the code, removing and in some cases adding requirements for some building elements.

Current HUD–USDA Standard and Subsequent Revisions

In May 2015, HUD and USDA published a Final Determination that established the 2009 IECC as the minimum standard for both new single-family housing built with HUD and USDA assistance and new HUD-assisted or FHA-insured low-rise multifamily housing.¹⁰ HUD and USDA estimated that 3,200 multifamily units and 15,000 single family units per year could potentially be impacted in the 16 states that had not yet adopted either of these codes. The average incremental cost of

⁷ Table 2 includes HUD and USDA programs supporting new construction with energy code requirements. Does not include other HUD or USDA programs that may have appliance or product standards or requirements only.

⁸ The IECC covers both residential and commercial buildings. States that adopt the IECC (or portions thereof) may choose to adopt the IECC for residential buildings only or may extend the code to commercial buildings (which include multifamily residential buildings of four or more stories). Chapter 4 of the IECC Commercial Code allows compliance with ASHRAE 90.1 as an optional compliance path.

⁹ In the early 2000s, researchers at the U.S. Department of Energy's Pacific Northwest National Laboratory prepared a simplified map of U.S. climate zones. The map was based on analysis of the 4,775 U.S. weather sites identified by the National Oceanic and Atmospheric Administration, as well as widely accepted classifications of world climates that have been applied in a variety of different disciplines. This PNNL-developed map divided the United States into eight temperature-oriented climate zones. See https://www1.eere.energy.gov/buildings/publications/pdfs/building_america/4_3a_ba_innov_buildingscience_climatemaps_011713.pdf.

¹⁰ Federal Register Notice 80 FR 25901, May 6, 2015.

the higher standard was estimated to be \$1,019 per unit, with

average annual savings of \$215, for a 5-year payback and a 1.3-year net positive cash flow. HUD and USDA determined that adoption of the 2009 IECC would not negatively impact the affordability and availability of the covered housing. The 2009 IECC represented a significant increase in energy efficiency of 7.9 percent and a 10.8 percent cost savings over the previous (2006) code.

Since HUD and USDA's adoption of the 2009 IECC, there have been four revisions to the IECC.¹¹ No action was taken by the prior Administration to comply with the statutory requirements to consider or adopt these updated codes.

The figure below shows the average national energy cost savings estimated with each version of the IECC. The greatest incremental savings come from the 2012 IECC (23.9%), followed by the 2009 IECC (10.8% over the 2006 IECC), followed by the 2021 IECC (8.7%). The Department of Energy's Pacific Northwest National Laboratory (PNNL) provided HUD with cost and benefit estimates for adopting the 2021 IECC from a baseline of the 2009 IECC and has made publicly available estimates for adopting the 2021 IECC from a 2018 IECC baseline. For states that have adopted standards equivalent to the 2012 or 2015 IECC, HUD and USDA use the estimates for the adoption from the 2018 to the 2021 IECC, as the 2012 and 2015 IECC both are closer to the 2018 IECC than the 2009 IECC.

INCREMENTAL ENERGY SAVINGS ASSOCIATED WITH EACH IECC VERSION [2006 to 2021]¹²

Year of code	Comparison year	National weighted energy cost savings (%)
2009	2006	10.8
2012	2009	23.9
2015	2012	0.7
2018	2015	2.0
2021	2018	8.7

Each successor edition since the 2009 IECC has increased energy efficiency

¹¹ IECC 2012, 2015, 2018, and 2021.

¹² Sources: DOE, 2012: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22068.pdf; 2015: https://www.energycodes.gov/sites/default/files/2021-07/2015_IECC_FinalDeterminationAnalysis.pdf; 2018: <https://www.energycodes.gov/sites/default/files/2021-07/EERE-2018-BT-DET-0014-0008.pdf>; 2021: <https://www.regulations.gov/document/EERE-2021-BT-DET-0010-0006>.

and offered cost savings to consumers in varying degrees:

(1) The 2012 IECC was published in May 2011, representing a significant increase of 23.9 percent in energy cost savings over the 2009 IECC.^{13 14} Key changes in the 2012 edition included: increased stringency for opaque thermal envelope components; clarification that sun rooms enclosing conditioned spaces must meet the thermal envelope provisions; requirements for a blower door test to determine the air leakage rate and limits for the number of prescribed air changes per hour (ACH) per climate zone; insulation to at least R-3 for hot water piping; and an increase in the minimum number of high-efficacy electrical lighting sources from 50 percent to 75 percent of permanent fixtures or lamps in permanent fixtures.^{15 16} This translated into an estimated \$500 or 32.1 percent annual cost savings per unit over the 2006 IECC.¹⁷

(2) The 2015 IECC was substantially the same as the 2012 edition, with a modest increase in energy efficiency of just 0.87 percent over the 2012 IECC.¹⁸ Revisions in this edition included: revised provisions for existing buildings; removal of exemption for historic buildings; revised requirements for building envelope and duct leakage testing and hot water distribution efficiency. The most notable innovation was the introduction of a new Energy Rating Index (ERI) performance path

¹³ U.S. Department of Energy, "Updating State Residential Building Energy Efficiency Codes: Notice of Final Determination," **Federal Register** Notice 77FR 29322, May 17, 2012. <http://www.gpo.gov/fdsys/pkg/FR-2012-05-17/pdf/2012-12000.pdf>.

¹⁴ Pacific Northwest National Laboratory, *Cost-Effectiveness Analysis of the 2009 and 2012 IECC Residential Provisions—Technical Support Document*, U.S. Department of Energy, PNNL-22068, April 2013. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22068.pdf.

¹⁵ Pacific Northwest National Laboratory, *Guide to the Changes between the 2009 and 2012 International Energy Conservation Code*, U.S. Department of Energy, PNNL-21435, May 2012. http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-21435.pdf.

¹⁶ Pacific Northwest National Laboratory, *Energy savings for a Typical New Residential Dwelling Unit Based on the 2009 and 2012 IECC as Compared to the 2006 IECC*, Letter Report, PNNL-88603, April 2013, Table 1.

¹⁷ Pacific Northwest National Laboratory, *Cost-Effectiveness Analysis of the 2009 and 2012 IECC Residential Provisions—Technical Support Document*, U.S. Department of Energy, PNNL-22068, Tables 8.1 and 8.4, April 2013.

¹⁸ U.S. Department of Energy, *Determination Regarding Energy Efficiency Improvements in the 2015 International Energy Conservation Code*, EERE-2014-BT-DET-0030-0007, June 2015. 80 FR 33250, June 11, 2015. <http://www.regulations.gov/#/documentDetail;D=EERE-2014-BT-DET-0030-0007>.

that utilizes the Home Energy Rating System (HERS) Index.

(3) The 2018 IECC also saw limited changes to the prior edition. In its efficiency determination for the 2018 IECC, DOE found site energy savings over the prior code of just 1.68 percent; 1.91 percent source energy savings; and 1.97 percent annual energy cost savings.¹⁹ Of the 47 changes in this edition, most were expected to have a neutral impact on energy efficiency, with two changes making up most of the energy savings associated with the updated code: (1) lower fenestration U-factors in Climate Zones 3 through 8, and (2) an increase in high-efficacy lighting from 75 percent to 90 percent of permanently installed fixtures in all climate zones.

2021 IECC—Overview

As required by statute, this Notice addresses the most recent edition of the IECC, the 2021 IECC.²⁰ In its efficiency determination for this standard, DOE determined that this edition would result in significant savings relative to the 2018 IECC: 9.4 percent savings in annual site energy use intensity (EUI); 8.8 percent in annual source EUI; 8.7 percent in annual energy cost savings; and 8.7 percent reduction in carbon emissions.²¹ The 2021 standard will yield a national weighted energy cost savings of 34.4 percent over the current USDA-HUD baseline 2009 standard.

In their qualitative assessment of the code, PNNL identified a total of 114 approved code changes or addenda in this edition of the code over the prior edition, of which 35 will have a direct impact on energy use in residential buildings. Of these, 29 are expected to

¹⁹ DOE, "Final Determination Regarding energy efficiency Improvements in the 2018 International Energy Conservation Code," **Federal Register** Notice, 84 FR 67435 (December 10, 2019). <https://www.federalregister.gov/documents/2019/12/10/2019-26550/final-determination-regarding-energy-efficiency-improvements-in-the-2018-international-energy-conservation-code>; also PNNL for DOE, *Energy Savings Analysis: 2018 IECC for Residential Buildings*, November 2019, <https://www.energycodes.gov/sites/default/files/2021-07/EERE-2018-BT-DET-0014-0008.pdf>.

²⁰ International Code Council, *2021 International Energy Conservation Code*, January 29, 2021. <https://codes.iccsafe.org/content/IECC2021P1>.

²¹ 86 FR 40529 (July 28, 2021), *Analysis Regarding Energy Efficiency Improvements in the 2021 International Energy Conservation Code (IECC)* <https://www.federalregister.gov/documents/2021/07/28/2021-15969/analysis-regarding-energy-efficiency-improvements-in-the-2021-international-energy-conservation-code>; also PNNL, *Preliminary Energy Savings Analysis: 2021 IECC for Residential Buildings*, April 2021, https://www.energycodes.gov/sites/default/files/2021-07/2021_IECC_PreliminaryDetermination_TSD.pdf.

reduce energy use, while six are expected to increase energy use.²²

The following are the primary technical changes in the 2021 IECC over the previous edition:

- **Building Envelope.** Building envelope revisions include increased insulation requirements; more efficient U factors and Solar Heat Gain Coefficients (SHGCs) for windows and fenestration; maximum air leakage rate of 5 Air Changes per Hour (ACH) at 50 pascals for all compliance paths, with 3 ACH for Climate Zones 3–8 following the prescriptive path. Testing alternatives are provided for smaller homes and attached single-family and multifamily buildings.²³

- **Heating, Ventilation and Air Condition (HVAC).** Mechanical ventilation in Climate Zones 7 and 8 provided by a Heat Recovery Ventilator (HRV) or Energy Recovery Ventilator (ERV) is required for the prescriptive compliance path.²⁴

- **Additional Efficiency Options.** Additional efficiency options in the 2021 IECC include an enhanced envelope performance option—a 5 percent improvement in proposed home UA value (R408.2.1); a more efficient HVAC equipment option (highlighted above); a reduced energy use in service water heating option 0.82 EF for fossil fuel, 2.0 EF for electric fuels or 0.4 solar fraction water heater (R405.2.3); a more efficient duct thermal distribution system option—100 percent of ducts in conditioned space or ductless systems (R405.2.4); and an improved air sealing and efficient ventilation option—air leakage at 3.0 ACH50 with ERV or HRV

with 75 percent Sensible Recovery Efficiency (SRE) (R405.2.5).

- **Lighting Changes.** The efficacy value of high-efficacy lamps increases to 70 lumens/watt (100 percent of lighting), a 10 percent increase over the 2018 standard.

- **Renewables.** The 2021 IECC revises the definition for “on-site renewables” for consistency with other national standards; adds a definition for biogas and biomass; requires that Renewable Energy Certificates (RECS) be retired with the homeowner when using the ERI compliance approach.²⁵

- **Zero Energy Appendix.** In addition to these technical changes, the 2021 IECC for the first time includes a Zero Energy Appendix that requires compliance with an ERI score without considering renewables and then achieving a score of “0” with renewables. This provides jurisdictions with an opportunity to adopt a base or stretch code that achieves zero energy in homes and low-rise multifamily buildings.²⁶

- **Building Electrification.** While the 2021 IECC did not include building electrification provisions in the final version of the code, provisions are available for adoption by states as amendments to the 2021 IECC: RE147–19, Electrification-Ready; RE126–19, Energy Efficient Water Heating, RE107–19, Eliminate Continuous Burning Pilot Light.

- **Compliance Pathways.** There are three compliance pathways in the 2021 IECC: Prescriptive, Performance, and Energy Rating Index or ERI, which reverted to IECC 2015 levels. The prescriptive paths can follow the R-value minimum table, the U-Factor

equivalent table, or the UA equivalent alternative. All compliance pathways now have required Additional Efficiency Options (AEOs) to achieve five percent greater energy efficiency than base levels. The 2021 IECC lowers the performance path ERI scores compared to the 2018 IECC.

Current State Adoption of the 2021 IECC

There is typically a lag time between the publication of a new edition of the IECC and state adoption of the code: Table 3 and Figure 1 show that, as of September 2022, while all but eight states have adopted a version of the IECC, only three states (California, Washington, and Vermont) have adopted the 2021 IECC or its equivalent.²⁷

Overall, thirty-nine states plus the District of Columbia have adopted a version of the code that is equivalent to or higher than the current HUD–USDA standard of the 2009 IECC. Of these, only 11 states plus the District of Columbia have adopted a code above the 2009 IECC (the 2018 IECC, the 2015 IECC or equivalent to the 2021 IECC),²⁸ while 26 states have set their codes at the equivalent of the 2009 IECC. The remaining 11 states have either adopted standards that pre-date the 2009 IECC (3 states) or have no state-wide codes (8 states).

Based on historical experience, and the fact that an additional six states are currently considering the adoption of the 2021 IECC for adoption in 2023, it is anticipated that over time additional states are likely to adopt the 2021 IECC, either as published by the ICC or with amendments.

TABLE 3—CURRENT ADOPTION OF THE IECC

[As of September 2022]

Above Current HUD–USDA Standard (14 states + DC)	
2021 IECC or Equivalent (3)	
California Washington.	Vermont.
2018 IECC or Equivalent (8 states + DC)	
Oregon Maryland Massachusetts District of Columbia	Nebraska. Delaware. New York. New Hampshire.

²² 79 additional changes were determined to be administrative or impact non-energy portions of the code.

²³ AMCA International, *International Energy Conservation Code: 2021 Changes, Getting Involved in the 2024 Process*, May 5, 2021, https://www.amca.org/assets/resources/public/assets/uploads/FINAL_ICC_Webinar_presentation_May_5_2021.pdf.

²⁴ Northeast Energy Efficiency Partnerships, *Key Changes in the 2021 IECC for the Northeast and Mid-Atlantic*, https://neep.org/sites/default/files/media-files/2021_iecc_one-pager_.pdf.

²⁵ New Buildings Institute, *2021 IECC National Model Energy Code (Base Codes)*, https://newbuildings.org/code_policy/2021-iecc-base-codes/.

²⁶ Ibid.

²⁷ California’s Title 24 2019 Building Energy Efficiency standard, Washington’s 2018 State Energy Code, and Vermont’s amendments to the 2018 IECC were determined to meet or exceed the 2021 IECC.

²⁸ PNNL, *State Level Residential Codes Energy Use Index, FY 2023Q2*, Excel File at <https://www.energycodes.gov/state-portal>. Note that as of March 2023, two additional states have adopted the 2021 IECC.

TABLE 3—CURRENT ADOPTION OF THE IECC—Continued
[As of September 2022]

Pennsylvania.	
2015 IECC (3)	
Maine Texas.	Hawaii.*
Current HUD—USDA Standard 2009 IECC or Equivalent (25)	
Alabama Connecticut Florida Georgia Idaho Illinois Indiana Iowa Kentucky Louisiana Michigan Minnesota Montana.	Oklahoma. Nevada. New Jersey. New Mexico. North Carolina. Ohio. Rhode Island. South Carolina. Virginia. West Virginia. Wisconsin. Utah.
Older than 2009 IECC Or No Statewide Codes (11)	
Less Than 2009 IECC (3)	
Arkansas Arizona*.	Tennessee.
Home Rule/No statewide code (8)	
Alaska Missouri Wyoming South Dakota	Colorado. Kansas. North Dakota. Mississippi.
U.S. Territories	
American Samoa—No Code Guam—2009 IECC U.S. Virgin Islands—2009 IECC	N. Mariana Islands (2003 IECC equivalent). Puerto Rico (2011 PR Building Standard).

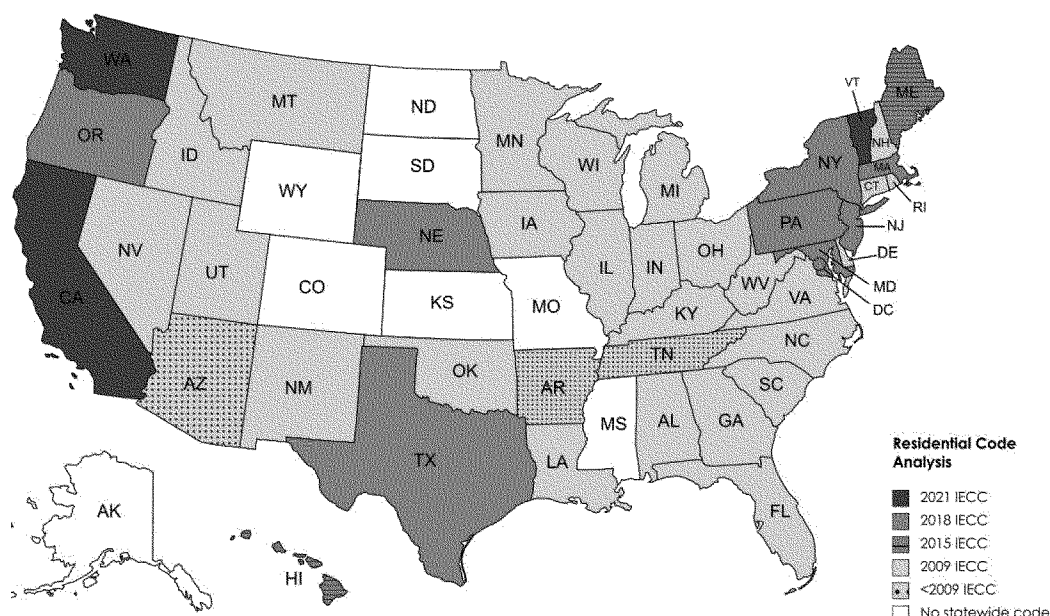
* A review of the codes in place across the state indicates that 86 percent (Hawaii) and 82 percent (Arizona) of the population is covered by codes at this level.

This tabulation is drawn from DOE's tracking of state adoptions of the IECC, available at DOE's state portal at [https://](https://www.energycodes.gov/state-portal)

www.energycodes.gov/state-portal. For the purpose of this Notice, HUD and USDA rely on the status map

maintained by DOE at this site. Figure 1 displays the state IECC adoption status shown in Table 3.

**Figure 1 – IECC Adoption Map (Residential)
Status as of September 2022**



Note that states often adopt amendments to the code as published by the ICC. In some cases, these amendments will sufficiently alter the IECC code as published, such that the energy performance of buildings meeting the amended code provisions may be equivalent to that of a prior code. The DOE code adoption map, and the adopted codes listed in Table 3, reflect DOE/PNNL's analysis of state codes as amended and DOE/PNNL's assessment of their equivalent code. Accordingly, 22 states have adopted the 2012, 2015 or 2018 IECC with amendments and were determined by PNNL to be equivalent to the 2009 IECC. These are therefore shown in Table 3 and Figure 1 as at the 2009 IECC level.²⁹ Ohio, for example, adopted the 2018 IECC with amendments to basement and crawl space wall R-values, air leakage rates and the allowance to utilize framing cavities as return ducts.³⁰ DOE/

PNNL determined that the Ohio code as adopted with amendments is equivalent to the 2009 IECC.³¹ New Mexico adopted the New Mexico Energy Conservation Code, based on the 2018 IECC, with state-specific amendments which were determined by DOE/PNNL to yield a performance standard equivalent to the 2009 IECC. On the other hand, if the new code is less than one percent more efficient than the prior code then DOE counts the newer code as equivalent to the previous code—hence Texas is credited here with the 2018 standard rather than the code they adopted (2015 IECC). California has adopted its own standard, Title 24, which DOE has determined meets or exceeds the 2021 IECC.

In certain cases, home rule cities or counties within a State may adopt a different code from the rest of the State. For example, Austin, Texas has adopted the 2021 IECC energy code, thereby exceeding the minimum Texas

statewide code of the 2015 IECC, equivalent to the 2018 IECC.³² In instances where a local entity has a more stringent standard, the affordability impacts within a State will differ.³³

Estimated Impacts

Table 4 provides an estimate of the average number of units that may be impacted annually by adoption of the 2021 IECC. HUD and USDA used prior-year production for these programs in order to estimate future annual production for these programs.³⁴ Based on average annual production for the past three years (2019–21), the agencies estimate that a total of approximately 161,700 units of HUD- and USDA-financed or insured housing may be impacted by the 2021 IECC, of which 151,300 are in the 47 states plus DC and U.S. territories that have not yet adopted this standard.

²⁹ The 21 states deemed equivalent to the 2009 IECC are: CT, FL, GA, IA, ID, IL, IN, MI, MN, MT, NC, NH, NJ, NM, NV, OH, PA, RI, UT, VA. See Table for a listing of these code equivalents at <https://www.energycodes.gov/state-portal> and "Residential State Level Results" Excel file at "Available Data" for detailed DOE/PNNL analysis.

³⁰ ACEEE, State Scorecard Ranking, <https://database.aceee.org/state/ohio>.

³¹ See "Residential State Level Results" at <https://www.energycodes.gov/state-portal>.

³² City of Austin, *Building Technical Codes*, <https://www.austintexas.gov/department/building-technical-codes>.

³³ HUD and USDA do not maintain a list of local communities that may have adopted a different code than their state code. See ACEEE, State and Local Policy Database for codes adopted by

individual cities. <https://database.aceee.org/city/energy-code-stringency>.

³⁴ Three-year averages were used (2019–21) for all programs, except for public housing which used 2016–2020 averages since limited data were available for the three-year period. Prior-year production data provided by program offices using internal tracking or reporting systems.

TABLE 4—ESTIMATED NUMBER OF UNITS IMPACTED ANNUALLY BY 2021 IECC

State or territory	FHA single family	USDA guaranteed loan program	USDA direct loan program	FHA single family—condos	Public housing	HOME	Housing trust fund *	RAD	Low-rise multi-family	Total
AK	42	27	19	3	0	35	19	25	0	170
AL	1,975	611	27	0	52	60	0	0	321	3,046
AR	1,024	453	52	0	0	145	12	16	164	1,866
AZ	4,595	391	90	54	0	97	0	38	432	5,697
CA (2021)	5,629	136	339	803	12	880	0	12	166	7,977
CO	2,701	151	42	65	13	199	1	10	682	3,864
CT	70	9	0	7	23	42	0	0	125	276
DC	17	0	0	8	12	0	0	0	137	174
DE	584	179	25	20	0	5	0	48	0	860.5
FL	19,178	1,119	189	24	146	366	87	21	1,477	22,607
GA	7,977	731	45	17	32	139	0	0	795	9,736
HI	77	61	39	40	3	33	0	0	0	253
IA	224	44	5	0	0	16	5	0	0	294
ID	812	134	13	0	0	56	29	73	11	1,128
IL	750	10	2	4	35	96	0	0	404	1,301
IN	1,890	205	137	1	0	121	0	0	49	2,403
KS	161	29	1	0	0	39	30	0	55	315
KY	798	277	66	13	0	71	0	2	188	1,415
LA	2,181	1,036	42	0	12	189	2	3	124	3,589
MA	174	7	7	11	0	20	0	35	491	745
MD	2,073	171	5	150	0	143	0	0	849	3,391
ME	116	48	16	0	0	40	30	24	15	288.5
MI	227	73	32	234	16	93	0	0	102	777
MN	542	99	16	1	3	120	0	5	607	1,393
MO	896	306	6	2	0	236	2	0	444	1,892
MS	1,048	304	43	2	1	0	0	0	0	1,398
MT	120	50	22	0	0	35	3	21	68	318.5
NC	4,977	1,211	165	2	7	724	25	0	1,321	8,432
ND	112	14	1	0	0	27	13	0	0	167
NE	177	9	1	0	0	17	0	0	297	501
NH	69	5	1	2	0	50	6	46	106	285
NJ	477	8	3	43	42	151	0	0	50	774
NM	751	21	26	0	0	11	15	12	115	950.5
NV	1,642	52	6	101	4	408	3	1	92	2,309
NY	233	5	6	3	15	262	0	27	1,445	1,996
OH	1,339	51	17	25	10	229	0	0	105	1,776
OK	1,464	288	41	0	0	34	13	10	81	1,931
OR	703	127	31	22	0	142	12	30	38	1,105
PA	697	78	13	4	43	90	0	0	85	1,010
RI	64	0	3	1	0	3	23	2	35	130.5
SC	4,169	992	87	3	0	44	0	0	236	5,531
SD	148	49	16	1	0	124	75	37	12	461.5
TN	3,355	644	55	9	2	39	30	103	751	4,988
TX	32,070	1,670	98	325	83	243	57	0	6,684	41,230
UT	1,679	417	127	103	0	7	0	17	476	2,826
VA	2,119	416	71	178	12	85	45	0	924	3,850
VT (2021)	10	4	2	0	0	59	24	0	9	108
WA (2021)	1,529	128	81	45	15	107	6	31	413	2,355
WI	168	24	7	0	5	85	0	0	173	462
WV	298	221	3	0	0	12	10	5	71	620
WY	55	32	3	0	0	16	1	0	18	125
Territories:										
Guam			8			18				26
Mariana Isl			9			3				12
Puerto Rico	186	284	53		53	5				581
Total	114,372	13,411	2,214	2,326	651	6,271	578	645	21,243	161,711
47 states	107,204	13,143	1,792	1,478	624	5,225	548	603	20,655	151,272

Table 4 includes both single-family and low-rise multifamily housing. Of the total, in the 47 states and the U.S. territories that have not yet adopted the 2021 IECC, approximately 107,200 units are estimated to be FHA-insured new single-family homes; approximately

13,100 units are USDA Section 502 direct loans, and 1,800 units are Section 502 guaranteed loans. The remaining single-family units are financed through the HOME program (5,200 units), HUD's Public and Indian Housing (PIH) programs (approximately 600 units

through the Choice Neighborhoods and Capital Fund Financing Programs, and 500 units through the Housing Trust Fund program). Also included in Table 4 are some 20,600 FHA-insured multifamily housing units financed with FHA multifamily insurance that are

estimated to be low-rise multifamily and therefore covered under the 2021 IECC.³⁵ When adjusted to exclude units in states that have already adopted codes equivalent to the 2021 IECC (California, Vermont, Washington), the total potential number of estimated units potentially impacted decreases to around 151,000 units.

Note that the volume of estimated production is not evenly distributed across the states but reflects historic demand for FHA and USDA financing for one or more of the agencies' programs: two states, Texas (24 percent) and Florida (14 percent), account for almost 40 percent of potentially impacted units based on prior-year production. Along with Georgia (6 percent), North Carolina (6 percent) and California (5 percent), five states account for more than half of all potentially impacted units (56 percent). Note that historical production is used as a guide to future production; actual state by state unit counts in the future may vary from these estimates, based on actual supply and demand.

B. 2021 IECC Affordability Analysis

In this Notice, HUD and USDA address two aspects of housing affordability in assessing the impact that the revised code will have on housing affordability. As described further below, the primary affordability test is a life-cycle cost savings (LCC) test, *i.e.*, the extent to which the additional, or incremental, investments required to comply with the revised code are cost effective inasmuch as the additional measures pay for themselves with energy cost savings over a typical 30-year mortgage period. A second test is whether the incremental cost of complying with the code as a share of total construction costs—regardless of the energy savings associated with the investment—is affordable to the borrower or renter of the home.

Note that there may be other benefits associated with energy efficient homes in addition to energy cost savings. A study by the University of North Carolina (UNC) Center for Community Capital and the Institute for Market Transformation (IMT) shows a correlation between greater energy efficiency and lower mortgage default risk for new homes. The UNC study

surveyed 71,000 Energy Star-rated homes and found that mortgage default risks are 32 percent lower for these more energy efficient homes than homes without Energy Star ratings.³⁶ In addition, studies show that added energy efficiency may also yield improved health outcomes.³⁷

Cost Benefit Analysis and Results

The core analysis used for this Determination is the PNNL study prepared for DOE, *National Cost Effectiveness of the Residential Provisions of the 2021 IECC*, published in June 2021. This analysis estimates annual energy and cost savings as well as life-cycle cost (LCC) savings that assume initial costs are mortgaged over 30 years.³⁸ The study provides an assessment of both the initial costs as well as the long-term estimated savings and cost-benefits associated with complying with the 2009 IECC.

The LCC method used by DOE is a “robust cost-benefit metric that sums the costs and benefits of a code change over a specified time frame. LCC is a well-known approach to assessing cost-effectiveness”³⁹ and reflects extensive prior public comment and input. In September 2011, DOE solicited input on their proposed cost-benefit methodology⁴⁰ and this input was incorporated into the final methodology posted on DOE's website in April 2012 and further updated in August 2015.^{41 42}

³⁶ UNC Center for Community Capital, Institute for Market Transformation, “Home Energy Efficiency and Mortgage Risks,” March 2013, Available at: http://www.imt.org/uploads/resources/files/IMT_UNC_HomeEEMortgageRisksfinal.pdf.

³⁷ See, for example, DOE, Jonathan Wilson et al, Home Rx: *The Health Benefits of Home Performance*, December 2016; HUD, *BRIGHT Study Finds Improved Health at Boston Housing Authority's Old Colony Homes*, <https://www.huduser.gov/portal/casestudies/study-05042017.html>.

³⁸ PNNL, Salcido et al, *National Cost Effectiveness of the Residential Provisions of the 2021 IECC*, June 2021. https://www.energycodes.gov/sites/default/files/2021-07/2021IECC_CostEffectiveness_Final_Residential.pdf.

³⁹ Department of Energy, *National Energy and Cost Savings for new Single- and Multifamily Homes: A Comparison of the 2006, 2009 and 2012 Editions of the IECC*, April 2012. p. A-1 Available at: https://www.energycodes.gov/sites/default/files/2020-06/NationalResidentialCostEffectiveness_2009_2012.pdf.

⁴⁰ 76 FR 56413 (September 13, 2011).

⁴¹ Pacific Northwest National Laboratory for the Department of Energy (Z. Taylor, R. Lucas, N. Fernandez) *Methodology for Evaluating Cost-Effectiveness of Residential Energy Code Changes*, April 2012. Available at: <http://www.energy.sc.gov/files/view/Taylor%202012.pdf>.

⁴² Pacific Northwest National Laboratory for the Department of Energy (V. Mendon, R. Lucas, S. Goel), *Cost-Effectiveness Analysis of the 2009 and 2012 IECC Residential Provisions—Technical Support Document*, April 2013, Available at https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22068.pdf.

For this analysis, DOE calculates energy use for new homes using EnergyPlus™ energy modeling software, Version 9.4.⁴³ Two buildings are simulated: (1) a two-story single-family home, with 2,376 square feet of conditioned floor area, excluding the conditioned basement (if any), and a window area equal to 15 percent of the conditioned floor area; and (2) a low-rise apartment building (a three-story multifamily prototype with six 1,200 square-foot dwelling units per floor) with a window area of approximately 23 percent of the exterior wall area. DOE combines the results into a composite average dwelling unit based on Census building permit data for each State and for eight Climate Zones. Single-family home construction is more common than low-rise multifamily construction; the results are weighted accordingly to reflect this for each Climate Zone as well as each state.

Four heating systems are considered for modeling the energy savings in these building prototypes: natural gas furnaces, oil furnaces, electric heat pumps, and electric resistance furnaces. The market share of heating system types is obtained from the U.S. Department of Energy Residential Energy Consumption Survey (2015). Domestic water heating systems are assumed to use the same fuel as the space heating system.

Limitations of Cost Savings Models

HUD and USDA are aware of studies that discuss limitations associated with cost-savings models such as those developed by PNNL for DOE. For example, Allcott and Greenstone suggest that “it is difficult to take at face value the quantitative conclusions of the engineering analyses” associated with these models, as they suffer from several empirical problems. The authors cite two problems in particular. First, engineering costs typically incorporate upfront capital costs only and omit opportunity costs or other unobserved factors. For example, one study found that nearly half of the investments that engineering assessments showed in energy audits for medium-size businesses that would have short payback periods were not adopted due to unaccounted physical costs, risks, or opportunity costs. Second, engineering

www.pnnl.gov/main/publications/external/technical_reports/PNNL-22068.pdf.

⁴³ Pacific Northwest National Laboratory for the Department of Energy (Z. Taylor, V. Mendon, N. Fernandez), *Methodology for Evaluating Cost-Effectiveness of Residential Energy Code Changes*, August 2015, Available at https://www.energycodes.gov/sites/default/files/2021-07/residential_methodology_2015.pdf.

³⁵ In order to derive the number of low-rise multifamily units, the following assumptions were made: for FHA units, 50 percent of all multifamily units are assumed to be low-rise; for public housing units, all units coded as “multifamily/walkup apartments” are assumed to be low-rise; and for HOME units, all units in multifamily developments with less than 100 units are assumed to be low-rise, as well as 50 percent of all units in developments with more than 100 units.

estimates of energy savings can overstate true field returns, sometimes by a large amount, and some engineering simulation models have still not been fully calibrated to approximate actual returns.⁴⁴ HUD and USDA nevertheless believe that the PNNL–DOE model used to estimate the savings shown in this Notice represents the current state-of-the-art for such modeling, is the product of significant public comment and input, is now the standard for all of DOE's energy code simulations and models, and presents a reliable and validated methodology for estimating energy code costs and benefits.

Estimated Costs and Savings

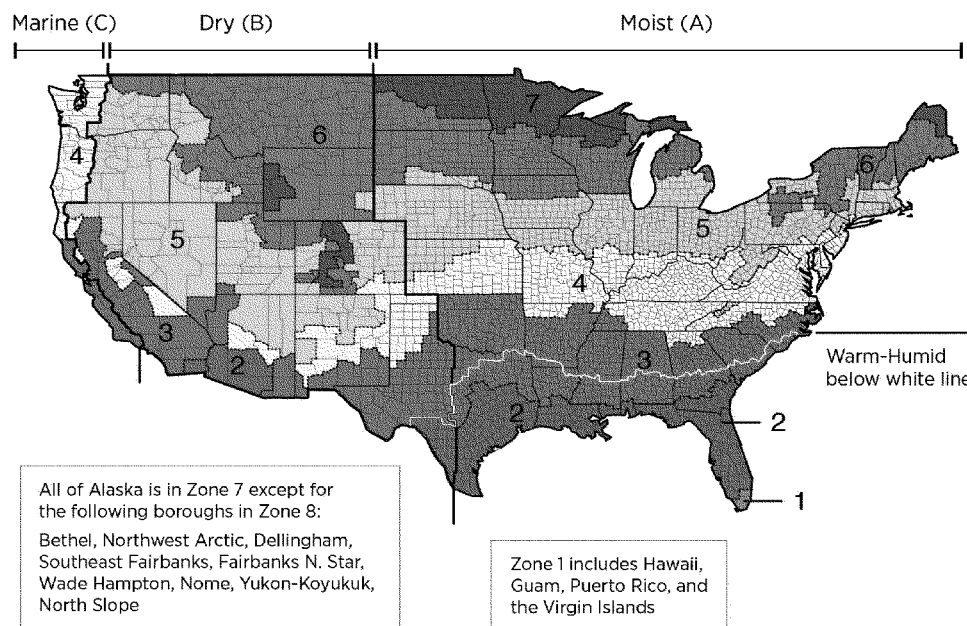
For all 50 states and the District of Columbia, DOE estimates that for a

weighted average of both single-family and low-rise multifamily housing, the 2021 IECC saves 9.38 percent of energy costs for heating, cooling, water heating, and lighting over the 2018 IECC.⁴⁵ For the purposes of this Notice, DOE provided HUD and USDA with a special tabulation that disaggregates this analysis into each building type (single family and low-rise multifamily). The disaggregated data are shown in Tables 5A (single family) and 5B (low-rise multifamily) for the following data points: LCC savings, incremental cost, annual mortgage increase, down-payment and other up-front costs, net first year annual cash flow, years to positive cash flow and simple payback for the 2021 IECC in relation to the current HUD–USDA baseline of the

2009 IECC. Tables 5A and 5B provide both national average costs and benefits, as well as for each climate zone.

Figure 2 provides a map of the Climate Zones. There are eight Climate Zones, further subdivided to represent moist, dry or marine climates, that are listed here with representative cities: 1A Very hot humid; 2A Hot Humid; 2B Hot Dry; 3A Warm Humid; 3B Warm Dry; 3C Warm Marine; 4A Mixed Humid, 4B Mixed Dry; 4C Mixed Marine; 5A Cool Humid; 5B Cool Dry; 6A Cold Humid; 6B Cold Dry; 7 Very Cold; and 8 Subarctic/Arctic. Zone 1 includes Hawaii, Guam, Puerto Rico and the Virgin Islands. Almost all of Alaska is in Zone 7.

Figure 2. Climate Zone Map



Tables 5A and 5B show the economics of adopting the 2021 IECC nationally and in each Climate Zone, relative to the 2009 IECC baseline. Table 5C shows costs and savings against the 2018 IECC baseline. Data points provided include, incremental or first costs, annual energy savings, increased debt service on a thirty-year mortgage, estimated down payment and closing costs, net annual cash flow in the first

year, and simple payback on the initial investment.⁴⁶

Incremental or Added Costs

Tables 5A shows the average per-unit incremental cost of adopting the 2021 IECC over the current HUD–USDA 2009 IECC baseline for single family homes, both nationally and for each Climate Zone: a national average of an estimated \$5,554 per unit for single family housing,⁴⁷ ranging from a low of \$2,813

in Climate Zone 1, to a high of almost \$6,800 in Climate Zones 7 and 8. Cost data sources used to derive these costs include: Building Component Cost Community (BC3) data repository; construction cost data collected by Faithful+Gould under contract with PNNL; RS Means Residential Cost Data; National Residential Efficiency Measures Database; and price data from

⁴⁴ Hunt Allcott and Michael Greenstone, "Is there an energy efficiency gap?" *Journal of Economic Perspectives*, Volume 26, Number 1, Winter 2012, pp. 3–28.

⁴⁵ PNNL, Salcido *et al.*, 2021

⁴⁶ The 2009 standard is used as the primary baseline for this analysis since, as shown in Table 3, 36 states are still at the 2009 baseline, which is also the most recent baseline established by HUD and USDA, while only eight states have adopted the 2018 standard. (Note that Table 6 below shows 2018

baseline data for individual states, per data provided by DOE/PNNL).

⁴⁷ Source: Data provided by DOE to HUD and USDA showing disaggregated LCC Savings, Incremental Cost, and Annual Energy Savings for single-family and low-rise multifamily homes.

nationally recognized home supply stores.⁴⁸

TABLE 5A—NATIONAL COSTS AND BENEFITS—2021 IECC VS. 2009 IECC (SINGLE FAMILY)

	LCC savings (\$)	Incremental cost (\$)	Annual energy savings (\$)	Annual mortgage increase (\$)	Down payment and other up-front costs (\$)	Net annual cashflow for year one (\$)	Years to positive cashflow (years)	Simple payback (years)
National	14,536.42	5,554.63	751.78	247.30	715.44	422.76	2	7.6
Climate Zone 1	9,080.84	2,813.49	474.75	125.26	362.38	308.10	2	6.1
Climate Zone 2	7,536.81	4,176.67	474.92	185.95	537.96	227.52	3	9.1
Climate Zone 3	13,753.10	6,175.22	750.85	274.93	795.37	385.08	3	8.5
Climate Zone 4	19,730.66	6,617.71	956.49	294.63	852.36	564.50	2	7.1
Climate Zone 5	17,368.88	5,954.78	851.84	265.12	766.98	499.12	2	7.2
Climate Zone 6	27,560.65	5,290.90	1,179.24	235.56	681.47	865.84	1	4.6
Climate Zone 7	35,673.62	6,794.41	1,544.15	302.50	875.12	1,141.69	1	4.5
Climate Zone 8	46,836.58	6,796.21	1,926.36	302.58	875.35	1,523.79	1	3.6

Annual Cost Savings

Table 5A summarizes the first-year annual energy cost savings per single family dwelling unit for the 2021 IECC compared to the 2009 IECC, aggregated over 16 single family residential prototype buildings modeled by DOE/PNNL.⁴⁹ Modeled energy savings are converted to cost savings using the most recent residential fuel prices from DOE's Energy Information Administration (EIA).⁵⁰ Cost savings stated are time zero dollars not adjusted for inflation or fuel price escalation. The per-unit annual energy cost savings for single-family homes is estimated to be \$752 per unit, ranging from \$474/unit in Climate Zones 1 and 2, to a high of \$1,926 in Climate Zone 8.

Simple Payback

Simple payback is a commonly used measure of cost effectiveness, defined as the number of years required for the sum of the annual returns on an investment to equal the original investment. The simple payback for adoption of the 2021 IECC code is an estimated 7.6 years for single-family homes, ranging from 3.6 years in Climate Zone 8 to 9.1 years in Climate Zone 2.

Total Life Cycle Cost Savings

LCC analysis computes overall cost savings per dwelling unit resulting from implementing efficiency improvements. LCC savings are based on the net change in overall cash flows (energy savings minus additional costs) resulting from

implementing the new code. LCC savings are a sum over an analysis period of 30 years: future cash flows vary from year to year and are discounted to present values using a discount rate that accounts for the changing value of money over time. LCC is the primary metric used by DOE to determine the cost effectiveness of the code or specific code changes. The economic analysis assumes that initial costs are mortgaged, that homeowners take advantage of the mortgage interest deduction, that short-lived efficiency measures are replaced at the end of the useful life of the equipment, and that all efficiency measures with useful life remaining at the end of the 30-year period of analysis retain a residual value at that point.⁵¹

Life cycle cost savings shown in Table 5A averages \$14,536 per housing unit for adoption of the latest 2021 IECC. LCC savings vary considerably by climate zone, from as low as \$7,536 in Climate Zone 2, to a high of \$46,836 in Climate Zone 8.

Consumer Cash Flows

Converting first costs and annual savings to Consumer Cash Flows is an important component of the affordability analysis. Consumer Cash Flow results are derived from the year-by-year calculations that underlie LCC savings and provide an assessment of how annual cost outlays are compensated by annual energy savings and the time required for cumulative energy savings to exceed cumulative

costs, including both increased mortgage payments and down payment and other up-front costs.

The financial and economic parameters used by DOE/PNNL in calculating LCC savings and annual cash flow are based on the latest DOE cost-effectiveness methodology; these are shown in Figure 3 below.

FIGURE 3—ECONOMIC PARAMETERS FOR CONSUMER CASH FLOWS

Mortgage interest rate (fixed rate).	5.0%.
Loan fees	1% of mortgage amount.
Loan term	30 years.
Down payment	12% of home value.
Nominal discount rate (equal to mortgage rate).	3.0%.
Inflation rate	1.4%.
Marginal Federal income tax.	12%.
Marginal State income tax.	% varies by State.
Property tax	% varies by State.

Source: PNNL, Salcido *et al.*, 2021.

Annual cash flow is defined as the net difference between annual energy savings and annual cash outlays (mortgage payments, etc.), including all tax effects but excluding up-front costs (mortgage down payment, loan fees, etc.). Only first year net cash flow is reported; subsequent years' cash flow will differ due to the effects of inflation and fuel price escalation, changing income tax effects as the mortgage

⁴⁸ See for example, PNNL, *Alaska Cost Effectiveness Analysis*, https://www.energycodes.gov/sites/default/files/2021-06/AlaskaResidentialCostEffectiveness_2018.pdf.

⁴⁹ For residential buildings, PNNL uses two base prototypes to simulate (1) a single-family detached house and (2) a multifamily low-rise apartment building. These prototypes are modified to accommodate four different heating system types

and four foundation types typically found in residential new construction. The result is an expended set of 32 models (16 for each building type) which is then simulated across 18 climate locations for each edition of the IECC. This results in a set of 3,552 energy models in EnergyPlus Version 9.5).

⁵⁰ U.S. Energy Information Administration, Washington, DC Natural Gas Prices, <https://>

www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_m.htm. Electric Power Monthly, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_06_b. Petroleum and Other Liquids. https://www.eia.gov/dnav/pet/PET_PRI_WFR_A_EPD2F_PRS_DPGAL_W.htm.

⁵¹ PNNL, Salcido *et al.*, 2021.

interest payments decline, etc. Assuming a five percent, 30-year fixed mortgage, and a 10 percent down payment, increased annual debt service is shown in Table 5A to be an average of \$247/unit, or \$20.58/month, with annual energy savings three times that amount: \$751, or \$62.50/month. This translates into an annual positive cash flow in Year One of \$422 or \$35.10/month. Years to Positive Cash Flow, *i.e.*, the number of years needed to recoup the cost of the initial down payment and first-year debt service with annual savings, is just two years on average.

Low-Rise Multifamily Buildings

Table 5B shows costs and savings for low-rise multifamily housing similar to

those shown in Table 5A for single family homes. The costs and savings shown are aggregated over 16 low-rise multifamily residential prototype buildings modeled by DOE/PNNL.⁵² The incremental costs for this housing type, as well as associated savings, are generally lower than for single family homes, as a result of both differences in unit size and building type. Incremental costs average \$2,306/unit nationally, approximately half of the \$5,556 per unit cost for single family housing only. LCC savings of \$5,265 for low-rise multifamily housing are also projected to be significantly lower than for single-family housing only (\$14,536/unit).

First year increased debt service for low-rise multifamily housing is

estimated to be \$102/unit, while savings are three times that amount: \$314/year, for a net annual cash flow of \$178/year. While costs and savings differ, Years to Positive Cash Flow are similar to that of single-family homes (2 years), and the national Simple Payback average of 7.5 years is also comparable. Simple paybacks range from a low of 5.1 years in Climate Zone 8 to a high of 8.1 years in Climate Zones 2 and 3. LCC savings vary considerably from \$4,064 in Climate Zone 2 to a high of \$15,452 in Climate Zone 8. Higher incremental or added costs typically translate into higher annual savings, with annual positive cash flows ranging from \$145 to \$525.

TABLE 5B—NATIONAL COST AND BENEFITS—2021 vs. 2009 IECC (LOW-RISE MULTIFAMILY)

	LCC savings (\$)	Incremental cost (\$)	Annual energy savings (\$)	Annual mortgage increase (\$)	Down payment and other up-front costs (\$)	Net annual cashflow for year one (\$)	Years to positive cashflow (years)	Simple payback (years)
National	5,265.55	2,306.50	314.77	102.69	297.08	178.15	2	7.5
Climate Zone 1	4,798.90	1,685.89	280.05	75.06	217.14	180.19	2	6.2
Climate Zone 2	4,064.66	2,138.91	271.97	95.23	275.49	145.27	2	8.1
Climate Zone 3	4,983.81	2,472.83	312.80	110.09	318.50	166.32	2	8.1
Climate Zone 4	5,994.21	2,372.29	339.34	105.62	305.55	198.82	2	7.2
Climate Zone 5	5,156.91	2,309.78	307.22	102.83	297.50	170.41	2	7.7
Climate Zone 6	8,231.86	2,147.46	407.58	95.61	276.59	280.38	1	5.4
Climate Zone 7	11,082.93	3,647.16	592.12	162.38	469.75	376.09	2	6.3
Climate Zone 8	15,452.48	3,646.44	741.63	162.34	469.66	525.64	1	5.1

Table 5C shows the energy savings and incremental costs of construction for the average housing unit (average of single family and multifamily). First costs average \$2,372 per unit, well

below the average first cost of \$5,550 against the 2009 baseline. As would be expected, annual savings are similarly lower, and the resulting average payback is higher than the 2009 IECC—

at 10.5 years vs. 7.6 years against the 2009 IECC. Simple paybacks vary considerably across Climate Zones, from 4.7 years in Climate Zone 1 to 16.5 years in Climate Zone 5.

TABLE 5C—INCREMENTAL COSTS AND ENERGY SAVINGS OF IECC 2018 TO IECC 2021⁵³

Area	Upfront cost for single-family (\$)	Upfront cost for condo (\$)	Upfront cost for average unit (\$)	First year energy savings for average unit (\$)	Simple payback for average unit (years)
National Average	2,372	1,316	2,013	191	10.5
Climate Zone 1: Very Hot	936	933	935	200	4.7
Climate Zone 2: Hot	1,530	1,146	1,400	192	7.3
Climate Zone 3: Warm	1,859	1,192	1,632	200	8.2
Climate Zone 4: Mixed	3,687	1,533	2,956	205	14.4
Climate Zone 5: Cool	3,569	1,487	2,862	173	16.5
Climate Zone 6: Cold	1,477	1,102	1,350	123	11.0
Climate Zone 7: Very Cold	2,980	2,603	2,852	306	9.3
Climate Zone 8: Subarctic/Arctic	2,982	2,603	2,853	411	6.9

Notes: Single Family cost and condo cost and average energy savings from PNNL. Upfront cost derived by HUD and simple payback calculated by HUD. HUD does not have disaggregated estimates for single family and multifamily units for the update from 2018, only the average across single family and low-rise multifamily.

⁵² See Footnote 47 for methodology for prototype buildings.

⁵³ HUD does not have PNNL estimates of energy savings disaggregated by single-family and

multifamily for the 2021 IECC relative to the 2018 standard. HUD computed a weighted average of the incremental cost of construction. The weights used by PNNL in their analysis are 66 percent for single-

family units and 34 percent for low-rise multifamily units.

State-Level Results

Table 6 provides a state-by-state breakout of estimated costs and savings, for single family homes only. This Table provides a more granular breakout of

estimated costs and savings than the national and Climate Zone averages shown in Table 5A above, using the HUD–USDA 2009 IECC baseline for those states that have not yet adopted

this standard or its equivalent as well as a 2018 IECC baseline for the 12 states plus the District of Columbia that have adopted the 2018 IECC or its equivalent.^{54 55}

TABLE 6—STATE BY STATE COSTS AND BENEFITS (SINGLE FAMILY) 2021 IECC VS. 2009 OR 2018 IECC

State	Baseline code	Incremental cost (\$)	Increase down payment (\$)	Annual mortgage (\$)	Annual energy savings (\$)	LCC savings (\$)	Payback (years)
AK	No Code	8,854	1,140	394	2,225	53,213	4.1
AL	2009	4,865	627	217	727	15,778	6.9
AR	<2009	5,358	690	239	775	16,713	7.1
AZ	<2009	4,163	536	185	499	9,125	8.6
CA	2021						
CO	No Code	5,788	746	258	549	9,699	10.9
CT	2009	6,616	852	295	1,028	21,114	6.6
DC	2018	397	13	138	397	6,864	8.0
DE	2018	424	16	146	298	4,636	11.4
FL	2009	3,369	434	150	440	7,818	7.9
GA	2009	5,228	673	233	756	15,657	7.1
HI	2015	2,340	301	104	1,057	27,120	2.3
IA	2009	5,694	733	253	998	22,037	5.9
ID	2009	5,291	682	236	493	8,485	11.1
IL	2009	6,487	836	289	679	11,067	9.8
IN	2009	6,207	800	276	696	13,176	9.2
KS	No Code	5,842	753	260	925	19,859	6.5
KY	2009	6,373	821	284	959	20,899	6.8
LA	2009	3,955	509	176	448	8,397	9.1
MA	2018	6,680	860	297	1,142	25,281	6.0
MD	2018	395	30	136	324	5,224	9.7
ME	2009	4,933	635	220	1,155	27,551	4.4
MI	2009	5,807	748	259	936	19,542	6.4
MN	2009	5,826	750	259	1,141	26,059	5.3
MO	No Code	6,701	863	298	827	16,518	8.4
MS	No Code	4,865	627	217	669	13,865	7.5
MT	2009	4,935	636	220	562	10,617	9.0
NC	2009	5,188	668	231	749	15,680	7.1
ND	No Code	5,123	660	228	976	21,463	5.4
NE	2018	427	61	148	211	1,040	16.2
NH	2009	5,542	714	247	995	21,242	5.7
NJ	2009	7,473	963	333	989	18,531	7.8
NM	2009	5,888	758	262	549	9,746	11.1
NV	2009	6,685	861	298	608	9,778	11.3
NY	2018	473	49	164	386	5,369	9.8
OH	2009	5,973	769	266	699	12,845	8.8
OK	2009	5,368	691	239	826	17,831	6.7
OR	2018						
PA	2018	4,144	539	187	426	2,535	10.1
PR							
RI	2009	6,372	821	284	1,090	23,668	6.0
SC	2009	4,885	629	217	732	15,816	6.9
SD	No Code	4,492	579	200	971	22,501	4.8
TN	<2009	5,561	716	248	748	15,424	7.7
TX	2015	195	32	68	216	3,311	7.2
UT	2009	5,238	675	233	519	9,414	10.4
VA	2009	5,897	759	263	904	19,799	6.7
VT	2021						
WA	2021						
WI	2006	5,823	750	259	862	17,198	7.0
WV	2009	6,423	827	286	943	20,790	7.0
WY	None	4,913	633	219	712	15,193	7.1

Incremental costs for adoption of the 2021 IECC in those states currently at

the 2009 IECC or its equivalent range from a low of \$2,340 (Hawaii) to a high

of \$8,854 (Alaska), with most states typically in the \$5,000 range. Annual

⁵⁴ Cost benefit data are not available for three states (California, Washington and Oregon). According to DOE, these codes “deviate

significantly from the model codes” and as a result DOE has historically not analyzed those states.

⁵⁵ The 2018 data shown in Table 6 are aggregated single family and low-rise multifamily data adjusted for the weighted averages used by PNNL for the 2009 IECC.

energy savings exceed added debt service in all states.

Both incremental costs and savings for the 2021 IECC in the 11 states plus the District of Columbia that have adopted the 2018 IECC are typically lower than for those at the 2009 IECC baseline. Incremental first costs are less than \$500 first cost/unit against the 2018 baseline in these states. New York, for example, shows an added cost of \$473/unit for adoption of the 2021 IECC relative to its current 2018 baseline,

\$386 in annual estimated savings, yielding LCC savings of \$5,369. Delaware shows an added cost of \$424/unit, an annual savings of \$298, and a LCC savings of \$4,636.

Total Costs and Benefits

Table 7 provides estimated up-front costs, annual energy cost savings and life cycle cost savings for the 2021 IECC for all 50 states and the District of Columbia, weighted by the estimated share of single-family and low-rise multifamily units potentially impacted

by the adoption of the 2021 IECC. As previously shown in Table 4, an estimated 140,000 single-family and low-rise multifamily units would be impacted annually by this code if adopted today. By multiplying the incremental cost/unit per state by the number of units estimated likely to be impacted, the total cost of implementing the 2021 IECC is preliminarily estimated at \$420.5 million, yielding an estimated annual savings of \$64 million and a life-cycle cost savings of \$1.14 billion.

TABLE 7—AGGREGATE ESTIMATED COST AND SAVINGS FOR 2021 IECC (SINGLE FAMILY AND LOW-RISE MULTIFAMILY)

State	Baseline code	Total incremental cost per state (\$)	Total energy cost savings per state (\$ per year)	Life-cycle cost (LCC) savings (\$)	Simple payback (years)
AK	NC	1,127,393	283,309	6,775,768	4.0
AL	2009	18,057,816	2,704,469	55,917,230	6.7
AR	<2009	8,288,783	1,202,143	23,974,946	6.9
AZ	<2009	19,883,153	2,386,661	39,378,344	8.3
CA	2021	0	0	0	0.0
CO	NC	16,940,650	1,608,095	24,607,251	10.5
CT	2009	979,129	149,471	3,309,762	6.6
DC	2018	95,717	96,264	845,064	1.0
DE	2018	727,164	509,989	7,590,775	1.4
FL	2009	59,952,314	7,876,622	125,801,672	7.6
GA	2009	41,644,334	6,039,069	109,876,655	6.9
HI	2015	492,777	217,851	4,856,670	2.3
IA	2009	2,201,675	383,939	7,431,325	5.7
ID	2009	4,962,175	461,960	6,750,699	10.7
IL	2009	7,824,969	819,313	10,407,259	9.6
IN	2009	11,586,682	1,299,580	21,741,652	8.9
KS	NC	3,009,893	476,735	7,966,904	6.3
KY	2009	11,142,041	1,678,812	28,628,785	6.6
LA	2009	9,255,670	1,054,429	20,336,338	8.8
MA	2018	2,678,880	450,003	8,594,306	6.0
MD	2018	1,077,820	888,574	13,922,015	1.2
ME	2009	1,060,695	247,256	5,297,721	4.3
MI	2009	3,963,075	631,850	14,160,179	6.3
MN	2009	5,459,528	1,018,941	27,561,549	5.4
MO	NC	8,703,440	1,078,725	19,861,036	8.1
MS	NC	6,258,788	860,339	16,896,275	7.3
MT	2009	1,195,888	136,034	2,232,087	8.8
NC	2009	31,297,407	4,545,258	88,763,865	6.9
ND	NC	1,052,232	200,451	3,162,698	5.2
NE	2018	128,294	62,463	356,167	2.1
NH	2009	1,035,284	183,401	4,007,029	5.6
NJ	2009	4,441,704	588,565	7,189,226	7.5
NM	2009	5,754,766	538,116	9,352,990	10.7
NV	2009	14,142,779	1,286,230	17,406,347	11.0
NY	2018	200,168	162,163	2,611,431	1.2
OH	2009	8,873,994	1,037,565	16,123,974	8.6
OK	2009	8,877,981	1,365,072	28,580,458	6.5
OR	2018	0	0	0	0.0
PA	2009	6,180,500	819,910	14,047,324	7.5
RI	2009	518,212	87,987	1,876,922	5.9
SC	2009	23,184,247	3,483,230	71,411,236	6.7
SD	NC	1,207,381	259,053	4,908,339	4.7
TN	<2009	22,760,783	3,072,624	58,511,424	7.4
TX	2018	6,304,697	6,980,223	96,334,751	0.9
UT	2009	12,810,311	1,271,438	21,270,223	10.1
VA	2009	17,825,103	2,760,236	58,859,601	6.5
VT	2021	0	0	0	0.0
WA	2021	0	0	0	0.0
WI	2006	1,388,510	204,039	3,760,117	6.8
WV	2009	3,521,350	517,015	10,091,785	6.8
WY	None	560,916	80,664	1,688,720	7.0

This LCC figure covers a single year's cohort of HUD and USDA financed housing. Annual effects will increase as more cohorts are added to the stock of new HUD- and USDA-assisted, insured or guaranteed energy-efficient housing. In the second year, with two cohorts in place, there could be a stream of almost \$150 million (future value) of energy savings. The number of units affected every year will decline as states update their standards to the 2021 IECC, or industry adopts the prescribed above-code standards. Thus, we expect the aggregate annual incremental effects to taper off. The maximum annual effect of all cohorts is not likely to exceed somewhere between three or four times the annual effect of a single-year cohort. While a new code edition is typically published every three years, since HUD and USDA must consider the affordability and availability impacts of each edition when it is published, this Notice LCC savings cover one year's cohort. See "Aggregate Incremental Impacts of IECC Update" in the Regulatory Impact Analysis (p.39) for further discussion.

The Regulatory Impact Analysis at www.regulations.gov provides an estimated first cost of \$553 million, annual energy savings of \$73 million and net LCC savings that range from \$971 million (7% discount factor) to \$1.48 billion (3% discount factor). (See RIA Figures 20 and 21).

C. Preliminary Affordability Determination—2021 IECC

Based on the analysis provided above, HUD and USDA have determined that adoption of the 2021 IECC will not negatively impact the affordability of homes covered by the statute. This conclusion recognizes the profile of FHA borrowers, who according to FHA's 2021 Annual Report are typically first-time home buyers (84 percent) who are more likely than repeat buyers to be especially price sensitive. While the national average cost shown in Table 5 of adopting this standard is \$5,500, this represents a 2.1 percent increase in the average cost of a new FHA-insured home in 2020, and the incremental costs (shown in Table 6) exceed \$5,000/unit relative to the 2009 IECC baseline in only nine states. In all cases this translates into a relatively modest increase in down payment and other first costs: a national average of \$715, which represents approximately 0.3 percent of the average FHA-insured new home mortgage, or an average USDA-guaranteed loan.⁵⁶ For qualifying

purposes, a hypothetical borrower earning \$5,000/month with a 4.5 percent down payment will require an additional income of \$85 (1.7 percent) a month to qualify for the average new home; and monthly payments will increase by \$31/month on a 30-year 4.25 percent fixed rate mortgage, from \$1,800/month to \$1,831/month.⁵⁷

Unlike other added costs associated with the home purchase transaction, these incremental costs yield significant costs savings to the borrower. In all Climate Zones, annual energy savings in Year One exceeds increases in debt service. Debt service increases average just \$20/month for net positive cash flows of \$35/month after debt service. While there is likely to be variability in actual cash flows depending on energy use associated with family size and behavior, the data shows that on average the adoption of these measures are likely to improve overall affordability in light of these positive cash flows.

An additional affordability consideration is whether increased down payment costs due to the added or incremental cost will negatively impact home buyers with regard to qualifying for a mortgage, or down payment requirements. This is especially important for first-time home buyers who typically have lower cash availability for down payments. PNNL estimates increased down payment and other up-front costs range from \$362 to \$875 for conventional mortgages.⁵⁸ Note that these down payments assume an average of 10 percent down, whereas the typical FHA borrower is likely to pay only 4.5 percent down;⁵⁹ the incremental down payment cost is therefore likely to be lower for FHA borrowers than the typical homeowner modeled by PNNL, with down payment increases ranging from as low as \$163 to \$393, which represent 0.06–0.15 percent of the average cost of an FHA new home in 2020, of \$263,000. At 5% down, the

of \$210,700. Incremental cost of \$5,500 equals 2.9 percent and 2.6 percent respectively of these loans; down payment costs are .27 percent and .34 percent. For average FHA new home mortgage of \$263,000 (2020), added first cost equals 2.1 percent, average down payment equals 2.1 percent.

⁵⁷ See Fannie Mae Financial Calculator, front-end Debt to Income ratio, monthly payment includes Principal, Interest, Property Taxes of \$1,500/year, Insurance of \$1,200/year and HOA payment of \$50/month. <https://fm.fanniemae.com/homeownership/resources/financial-calculators>.

⁵⁸ Average price in 2021 for all FHA-insured purchases, including existing homes, was \$239,000.

⁵⁹ HUD, *Annual Report to Congress Regarding the Financial Status of the Federal Housing Administration Mutual Mortgage Insurance Fund*, November 2021. <https://www.hud.gov/sites/dfiles/Housing/documents/2021FHAAnnualReportMMIFund.pdf>.

average downpayment increase is estimated to be \$278.

Note that energy costs and savings are generally not factored into current underwriting practices for single family mortgages, *i.e.*, while positive cash flows related to improved energy efficiency will be realized, they are not specifically included in the Principal Interest, Taxes and Insurance (PITI) debt-to-income ratios typically used by lenders to qualify borrowers. Conversely, despite the significant cost savings likely to be realized from adoption of more efficient energy codes, there are generally no direct incentives for borrowers to purchase more efficient homes either through lower Mortgage Insurance Premiums or lower interest rates. Multifamily financing, on the other hand, does take into account energy savings: FHA offers the Green Mortgage Insurance Premium to multifamily borrowers who build to a green building standard, which may include the most recent energy code as a mandatory element, or may offer additional points if the building meets or exceeds the latest IECC or ASHRAE 90.1 standard.

Equity Impacts

The Regulatory Impact Analysis (RIA) that accompanies this Notice includes an extensive equity analysis, which discusses the disproportionate energy burden experience by low-income borrowers—and conversely the increased benefits likely to be realized by low-income borrowers from increased efficiency. See the Equity Impacts section of the RIA (p.84) at www.regulations.gov.

Lower-income households face disproportionately higher energy burdens; they spend a higher share of their gross household income on energy costs.⁶⁰ Two-thirds of low-income households earning up to 200 percent of the federal poverty level face high energy burdens, spending more than 6 percent of their income on energy bills. Black, Hispanic, Native American, and older adult households, as well as families residing in manufactured housing and low-income households with a person with a disability, experience disproportionately high energy burdens.

Since increasing energy efficient codes will lower the energy burden for buyers of energy efficient homes; more efficient codes will at the same time be most beneficial to lower-income households. These codes typically require added first costs, but HUD and

⁵⁶ Average USDA Section 502 Direct Loan 2018–20 of \$191,100, and of Section 502 Guaranteed Loan

⁶⁰ <https://www.energy.gov/scep/slsc/low-income-community-energy-solutions>.

USDA single family insured or guaranteed programs include mitigating factors which may make this investment more affordable to eligible borrowers, e.g., lower down payment requirements (3.5% for FHA-backed mortgages compared to 20 percent required for conventional financing), as well as more flexible underwriting requirements such as lower allowable credit scores. USDA's Direct Loan program serves an underserved market, very low or extremely low-income borrowers in rural areas, through no- or low-down payment requirements, as well as significant interest rate subsidies. FHA's low-rise multifamily housing serves a renter population that is not directly responsible for any additional first costs.

The overall conclusion provided in the RIA concerning the equity impacts of a minimum energy standard are that lower-income households will benefit more from the existence of energy-efficient housing but may be challenged in their ability to address first costs. Empirical work has shown that residential energy is a necessary good, but that reducing its cost through energy efficiency requires an additional investment that lower-income households may not have the disposable income to accommodate. If, however, the Notice encourages the supply of energy efficiency in the affordable housing stock, then low- households will gain. Precise impacts are likely to vary by housing market and climate zone.

III. ASHRAE 90.1–2019 Affordability Determination

A. Overview

EISA requires HUD to consider the adoption of revisions to ASHRAE 90.1 for HUD-assisted multifamily programs.⁶¹ Published and revised every three years in coordination with the publication schedule of the IECC, the standard provides minimum requirements for the energy-efficient design of commercial buildings, including residential buildings with more than three stories.⁶²

ASHRAE 90.1 includes several compliance pathways. The first is the prescriptive path, which establishes energy-related criteria for individual building components, including minimum insulation levels, maximum

lighting power, and controls for lighting and heating, ventilation, air conditioning, and refrigeration systems. Some requirements are considered mandatory, even when one of the optional paths is utilized.

ASHRAE 90.1 also includes two optional whole-building performance paths. The first is the Energy Cost Budget method, which allows the designer to trade off compliance among various code requirements, using established energy modeling protocols. A building is deemed in compliance when the annual energy cost of the proposed design is no greater than the annual energy cost of the reference building design (baseline). ASHRAE 90.1 also includes a second performance approach, the Performance Rating Method in Appendix G. Appendix G has been used to rate the performance of buildings that exceed the requirements of Standard 90.1 for above-code programs, such as LEED, Green Globes, ASHRAE Standard 189.1, the International Green Construction Code, the National Green Building Standard, and other above-code programs.

Current HUD–USDA Standard and Subsequent Revisions

In their May 2015 Final Determination, HUD and USDA established the 2007 edition of ASHRAE 90.1 (ASHRAE 90.1–2007) as the minimum standard for HUD-assisted multifamily properties. ASHRAE has revised the code four times since the publication of the 2007 edition. ASHRAE 90.1–2010 was published in October 2010. There were 56 positive changes to the 2007 edition code, including revised requirements for the building envelope, HVAC systems, commissioning, lighting, and power.⁶³ DOE determined that the 2010 ASHRAE code would yield national energy cost savings of 7.72 percent in mid-rise apartment buildings and 6.99 percent in high-rise apartment buildings over the previous 2007 code.⁶⁴

The next edition, ASHRAE 90.1–2013, published in October 2013, included 52 changes over the 2010 edition, most of which were determined by DOE to be relatively minor. Only six were applicable to residential buildings, including improved lighting controls

and decreased lighting power densities, increased building envelope requirements for “opaque assemblies and fenestration,” and increased efficiency requirements for smaller air conditioners and heat pumps.⁶⁵ These amendments resulted in an average energy savings of 5.4 percent in mid-rise apartment buildings and 6.9 percent in high-rise multifamily buildings (site energy) over ASHRAE 90.1–2010.⁶⁶ Cost savings were estimated by DOE to be 5.0 percent for mid-rise apartments and 8.7 percent for high-rise apartments.

The following edition, ASHRAE 90.1–2016, yielded an additional 3.6 percent site energy savings for mid-rise apartment buildings, and 4.0 percent for high-rise apartment buildings.⁶⁷ Energy cost savings were estimated by DOE to be 3.9 percent and 5.1 percent respectively over the 2013 edition for these two building types.

DOE's quantitative analysis concluded that ASHRAE 90.1–2019 for mid-rise and high-rise multifamily buildings (representing 11.65 percent of all commercial buildings) would yield an additional site energy savings of 2.65 percent over the 2016 edition, and energy cost savings (Energy Cost Index (ECI)) of 2.5 percent.^{68 69 70}

Tables 8 and 9 show the changes in incremental costs for each code cycle since the 2007 edition. Table 8 shows that per square foot costs increased for

⁶⁵ PNNL, *National Cost-effectiveness of ANSI/ASHRAE/IES Standard 90.1–2013*, January 2015. See https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23824.pdf.

⁶⁶ U.S. Department of Energy, *Determination Regarding Energy Efficiency Improvements in ANSI/ASHRAE/IES Standard 90.1–2013: Energy Standard for Buildings, Except Low-Rise Residential Building*, September 26, 2014. Table IV.5. See <https://www.federalregister.gov/documents/2014/09/26/2014-22882/determination-regarding-energy-efficiency-improvements-in-ansiashraeies-standard-901-2013-energy>. For more detailed analysis, see PNNL, *ANSI/ASHRAE/IES Standard 90.1–2013 Determination of Energy Savings: Quantitative Analysis*, August 2014. Available at https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23479.pdf.

⁶⁷ PNNL/DOE *Preliminary Energy Savings Analysis, ANSI/ASHRAE/IES Standard 90.1–2016*, June 2017. Available at https://www.energy.gov/sites/default/files/2017/07/f35/Preliminary_90.1-2016_Energy_Savings_Analysis.pdf.

⁶⁸ *Op cit.*, PNNL, *Energy Savings Analysis*, July 2021.

⁶⁹ PNNL, *Impacts of Model Building Energy Codes—Interim Update*, July 21, 2021. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31437.pdf. For all commercial buildings, DOE estimates national site energy savings of 4.7 percent and energy cost savings of approximately 4.3 percent.

⁷⁰ 86 FR 40543 (July 28, 2021), *Final Determination Regarding Energy Efficiency Improvements in ANSI/ASHRAE/IES Standard 90.1–2019*, <https://www.federalregister.gov/documents/2021/07/28/2021-15971/final-determination-regarding-energy-efficiency-improvements-in-ansiashraeies-standard-901-2019>.

⁶¹ USDA multifamily programs are not covered by the Act.

⁶² Standard 90.1 is published in October of the year two years before the year listed for the IEC, to allow the latest version of standard 90.1 to be submitted to the IECC for inclusion in the commercial chapter of the IECC.

⁶³ A “positive change” is defined as a change to the code that results in increased energy efficiency. Other changes might include items that are either savings-neutral, or, in rare cases, may lower energy efficiency.

⁶⁴ Pacific Northwest National Laboratory for the Department of Energy, *Cost-effectiveness of ASHRAE Standard 90.1–2010 Compared to ASHRAE Standard 90.1–2007*, May 2013, Tables C.2. See http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22043.pdf.

the first two cycles (2010 and 2013) in a prototype mid-rise apartment building modeled by PNNL in five representative climate zones. In 2013, for example, the incremental cost of complying with ASHRAE 90.1 ranged from just 0.17 \$/

sf to 0.69 \$/sf, or 0.14 to 0.59 percent of total building costs. In contrast, the last two code cycles (both 2016 and 2019) have seen incremental cost savings rather than cost increases as a result of complying with these codes. In

all cases, the incremental cost, whether a cost increase or a cost savings, is a small fraction of the total per building first cost (111 \$/sf in 2010 to \$218 \$/sf in 2019).

TABLE 8—INCREMENTAL ASHRAE 90.1–2019 CONSTRUCTION COSTS
[\$/sf and %/sf]

Year	Building	2A	3A	3B	4A	5A
	First cost (\$/ft ²)	Tampa (\$/ft ²)	Atlanta (\$/ft ²)	El Paso (\$/ft ²)	New York (\$/ft ²)	Buffalo (\$/ft ²)
2019	\$218	(\$0.36) – 0.16%	(\$0.37) – 0.17%	(\$0.40) – 0.19%	(\$0.30) – 0.14%	(\$0.29) – 0.13%
2016	\$194	(\$0.54) – 0.28%	(\$0.51) – 0.27%	(\$0.53) – 0.27%	(\$0.37) – 0.19%	(\$0.73) – 0.38%
2013	\$117	\$0.17 0.14%	\$0.69 0.59%	\$0.69 0.59%	\$0.38 0.33%	\$0.58 0.50%
2010	\$111	\$0.62 0.56%	\$0.62 0.56%	\$0.62 0.56%	\$0.62 0.56%	\$0.62 0.56%

Table 9 shows building-level incremental cost or cost savings for each code cycle since 2007. In Climate Zone 2A (Tampa) for example, the

incremental cost for the prototype mid-rise building was estimated to be \$20,858 and \$5,711 for the 2010 and 2013 editions respectively, followed by

a combined savings of \$30,167 in the following 2016 and 2019 codes.

TABLE 9—INCREMENTAL ASHRAE 90.1 CONSTRUCTION COSTS
[\$/Prototype 32-Unit Building]

Code	Prototype bldg first cost		2A		3A	
		(\$/bldg)	Tampa	(\$/bldg)	Atlanta	(\$/bldg)
2019	\$7.36 million	(\$11,992)	(\$12,389)	(\$13,661)	(\$9,966)	(\$9,674)
2016	\$6.55 million	(\$18,175)	(\$17,353)	(\$17,944)	(\$12,430)	(\$24,614)
2013	\$3.95 million	\$5,711	\$23,214	\$23,358	\$12,891	\$19,577
2010	\$3.75 million	\$20,858	\$20,858	\$20,858	\$20,858	\$20,858

ASHRAE 90.1–2019 Overview

This Notice addresses the most recent published edition of ASHRAE 90.1, ASHRAE 90.1–2019. In its qualitative analysis of the code, DOE identified a total of 88 changes, or addenda, to ASHRAE 90.1–2016.⁷¹ ⁷² Twenty-nine

⁷¹ Pacific Northwest National Laboratory for the U.S. Department of Energy, *Energy Savings Analysis: ANSI/ASHRAE/IES Standard 90.1–2019*, July 21, 2021. https://www.energycodes.gov/sites/default/files/2021-07/Standard_90.1-2019_Final_Determination_TSD.pdf.

⁷² DOE determined that 59 of the 88 addenda will have a neutral impact on overall building efficiency; these included editorial changes, changes to reference standards, changes to alternative compliance paths, and other changes to the text of the standard that may improve the usability of the standard, but do not generally improve or degrade the energy efficiency of the building. Changes with impacts which do not become effective within three years from the publication of Standard 90.1–2019 (*i.e.*, until a cutoff date of December 31, 2022), are also

changes were determined to have a positive impact on energy efficiency (*i.e.*, yield energy savings). These include: increased requirement for building vestibules, removal of data processing centers from exceptions to HVAC requirements, removal of hotel room exceptions to HVAC requirements, modification of demand-controlled ventilation requirements, modification of fan power limitations, modification of retail lighting requirements, modification of cooling tower testing requirements, modification of commercial boiler requirements, modification of part load fan requirements, modification of opaque envelope requirements, and modification of fenestration envelope requirements.

considered as having no impact within the context of this analysis.

Current State Adoption of ASHRAE 90.1–2019

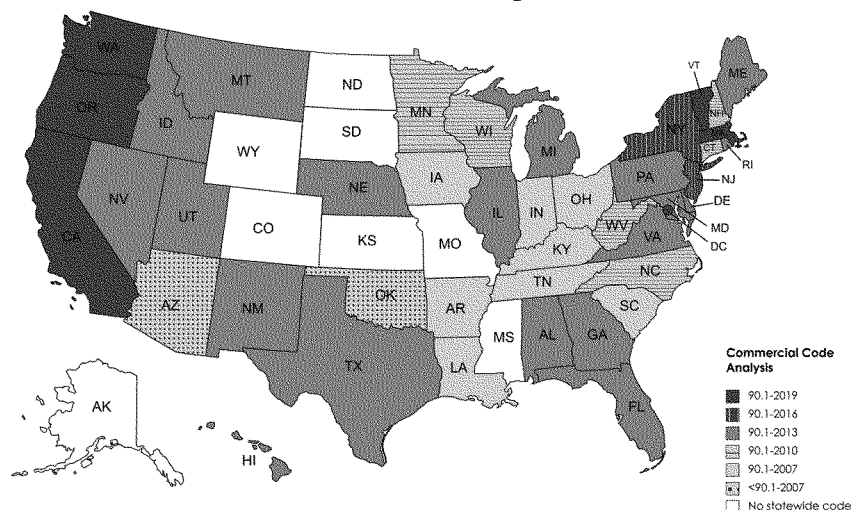
Table 10 shows the current adoption status of ASHRAE 90.1 for mid-rise or high-rise multifamily buildings. As of September 2022, five states have adopted ASHRAE 90.1–2019. A total of 32 states and the District of Columbia have adopted an ASHRAE standard that is equivalent to or above the current HUD–USDA standard (one of the 2010, 2013, 2016 or 2019 editions), while 18 states have adopted codes that are currently equivalent to or below the current HUD–USDA standard or have no statewide codes.⁷³

⁷³ DOE, *Status of State Energy Code Adoption—Commercial*, <https://www.energycodes.gov/status/commercial>. Note that the codes shown in Table 10 and Figure 4 represent DOE/PNNL's Determination of the standard that the state-adopted code is equivalent to, reflecting amendments that may have been adopted by each state.

TABLE 10—CURRENT ADOPTION OF ASHRAE 90.1 (SEPTEMBER 2022) MULTIFAMILY MID- AND HIGH-RISE BUILDINGS

Above Current HUD–USDA Standard (32 states and DC)	
ASHRAE 90.1 2019 (5 states plus DC)	
Washington California Massachusetts	Oregon Vermont District of Columbia
ASHRAE 90.1 2016 (2 states)	
New Jersey	New York
ASHRAE 90.1–2013 (19)	
Alabama Delaware Florida Georgia Idaho Illinois Michigan Maryland Maine Rhode Island.	Montana Nebraska Nevada New Mexico Pennsylvania Texas Utah Virginia Hawaii
ASHRAE 90.1–2010 (6)	
Connecticut New Hampshire North Carolina	Minnesota West Virginia Wisconsin
At or Below Current HUD–USDA Standard (18)	
ASHRAE 90.1–2007 (8)	
Arkansas Iowa Indiana Kentucky	Louisiana Ohio South Carolina Tennessee
No Statewide Code (8)	
Alaska Colorado (Home Rule) Kansas (Home Rule) Mississippi	Missouri (Home Rule) North Dakota (Home Rule) South Dakota (Home Rule) Wyoming (Home Rule)
Older Than ASHRAE 90.1–2007 (2)	
Arizona (Home Rule)	Oklahoma
U.S Territories	
Guam Puerto Rico U.S. Virgin Islands.	N Mariana Islands (2001) American Samoa

**Figure 4. ASHRAE 90.1 Adoption Map (Mid-Rise and High-Rise Multifamily)
Status as of September 2022**



Impacted Multifamily Housing

Table 11, below, provides the estimated number of new mid-rise or high-rise multifamily units that are estimated to be impacted annually by the proposed Determination on ASHRAE 90.1–2019. Using a three-year

average (2019 to 2021) annual production for each program, HUD preliminarily estimates that a total of 17,900 new mid- or high-rise multifamily units (four or more stories) will be impacted annually in the states that had not yet adopted this version of ASHRAE 90.1. This includes

approximately 13,700 FHA-insured multifamily units, 400 public housing units, and approximately 2,800 HOME- and 300 HTF-financed units. No USDA-guaranteed multifamily units are impacted since these are not covered under this Notice.

TABLE 11—HIGH RISE MULTIFAMILY UNITS POTENTIALLY IMPACTED BY ASHRAE 90.1–2019

State	PIH	HOME	Housing trust fund	RAD	FHA multifamily	Total
AK	0	18	13	25	0	56
AL	34	29	0	0	207	270
AR	0	67	8	16	105	196
AZ	0	58	0	38	278	374
CA (2019)	8	378	0	12	107	505
CO	8	72	0	10	440	530
CT	15	22	0	0	81	118
DC (2019)	7	0	0	0	89	96
DE	0	2	0	48	0	50
FL	94	124	56	21	953	1248
GA	21	80	0	0	513	614
HI	2	0	0	0	0	2
IA	0	3	3	0	0	6
ID	0	25	17	73	7	122
IL	22	56	0	0	260	338
IN	0	60	0	0	32	92
KS	0	4	19	0	36	59
KY	0	34	0	2	122	158
LA	8	105	1	3	80	197
MA	0	9	0	35	316	360
MD	0	77	0	0	547	624
ME	0	21	19	24	10	74
MI	11	54	0	0	65	130
MN	2	73	0	5	391	471
MO	0	138	1	0	286	425
MS	0	0	0	0	0	0
MT	0	19	2	21	44	86
NC	4	79	0	0	852	935
ND	0	17	8	0	0	25
NE	0	0	0	0	191	191
NH	0	33	4	46	69	152
NJ	27	75	0	0	32	134
NM	0	5	9	12	74	100
NV	3	216	2	1	59	281
NY	10	156	0	27	932	1125

TABLE 11—HIGH RISE MULTIFAMILY UNITS POTENTIALLY IMPACTED BY ASHRAE 90.1–2019—Continued

State	PIH	HOME	Housing trust fund	RAD	FHA multifamily	Total
OH	7	83	0	0	68	158
OK	0	0	7	10	52	69
OR (2019)	0	92	8	30	24	154
PA	27	45	0	0	54	126
RI	0	2	15	2	23	42
SC	0	10	0	0	152	162
SD	0	63	47	37	8	155
TN	1	9	16	103	484	613
TX	54	114	36	0	4,310	4514
UT	0	1	0	17	307	325
VA	8	38	9	0	596	651
VT (2019)	0	38	16	0	5	59
WA (2019)	10	47	4	31	266	358
WI	4	41	0	0	111	156
WV	0	5	6	5	46	62
WY	0	10	1	0	12	23
Territories						
Puerto Rico	41	86				127
Total	428	2,793	327	645	13,696	17,889
45 states + DC	417	2,229	299	538	13,067	16,550

B. ASHRAE 90.1–2019 Affordability Analysis

Cost Benefit Analysis

In its Final Determination of improved energy efficiency for commercial buildings, including multifamily buildings, DOE completes both a “qualitative” analysis and a “quantitative” analysis to assess increased efficiency of ASHRAE Standard 90.1.⁷⁴ In addition to a quantitative and qualitative analysis of the new code, PNNL publishes a cost benefit analysis of each of the codes, which considers the added, or incremental cost for the new standard. In addition, PNNL has published its methodology for evaluating the cost-effectiveness of commercial energy code

changes, including multifamily buildings, and that methodology is used by HUD and USDA for this determination.⁷⁵ For more detail on the methodology developed by DOE for their cost-benefit analysis, see PNNL’s 2015 cost-effectiveness report.⁷⁶

Evaluating cost-effectiveness requires three primary steps: (1) evaluating the energy and energy cost savings of code changes, (2) evaluating the incremental and replacement costs related to the changes, and (3) determining the cost-effectiveness of energy code changes based on those costs and savings over time. The DOE methodology estimates the energy impact by simulating the effects of the code change(s) on typical new buildings, assuming both old and new code provisions are implemented

fully and correctly. The methodology does not estimate rates of code adoption or compliance. Cost-effectiveness is defined primarily in terms of LCC evaluation, although the DOE methodology includes several metrics intended to assist states considering adoption of new codes.

Building Prototypes

The basis for DOE’s ASHRAE cost-benefit analysis are 16 prototype building models representing different commercial sector building types. Of the 16 prototypes modeled by DOE, two are multifamily buildings—a 4-floor mid-rise apartment building and a 10-floor high-rise apartment building. Table 12 provides detailed characteristics of the mid-rise prototype.

TABLE 12—MID-RISE APARTMENT BUILDING PROTOTYPE CHARACTERISTICS⁷⁷

GENERAL	
Building Type	Multifamily residential building.
Gross Floor Area	33,700 sf.
Building Shape	Rectangle.
Aspect Ratio	2.75 (152 ft x 56 ft).
Number of Floors	4.
Activity Area	Each floor has 8 (25' x 38') apartments, except ground floor which has 7 apartments and one lobby/office.
Window-to-Wall Ratio	15% (4 ft high view windows).
Floor Height	10 ft.
Floor-to-Ceiling Height	10 ft (for the office area only).
Exterior Wall	Steel-framed wall.
Roof	Insulation entirely above deck, metal deck roof.

⁷⁴ 86 FR 40543 (July 28, 2021), *Final Determination Regarding Energy Efficiency Improvements in ANSI/ASHRAE/IES Standard 90.1–2019*. <https://www.govinfo.gov/content/pkg/FR-2021-07-28/pdf/2021-15971.pdf>.

⁷⁵ PNNL, *Methodology for Evaluating Cost-Effectiveness of Commercial Energy Code Changes*, January 2015. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23923.pdf.

⁷⁶ Ibid.

⁷⁷ PNNL, *Impacts of Standard 90.1–2007 for Commercial Buildings at State Level*. https://www.pnnl.gov/main/publications/external00nal/technical_reports/PNNL-18544.pdf.

TABLE 12—MID-RISE APARTMENT BUILDING PROTOTYPE CHARACTERISTICS⁷⁷—Continued

Floor	8" Slab-on-grade.
INTERNAL LOADS	
Occupancy:	
Number of People	78 persons total (average 2.5 persons per apartment unit).
Lighting:	
Average Power Density	• Apartment units: 0.36 w/sf. • Corridors: 0.5 w/sf. • Office area: 1.1 w/sf.
Plug Load:	
Average Power Density	0.62 w/sf.
HVAC:	
Heating Type	Gas furnace.
Cooling Type	Split system DX (one per apartment).
Fan Control	Constant volume.
Distribution/Terminal Units	Single zone/direct air.
Cooling T-stat	75 °F (no setback assumed).
Heating T-stat	70 °F (no setback assumed).
WATER HEATER	
Water Heater Type	Individual residential electric storage water heater.
Tank Capacity, gallons	20 (per apartment unit).
Supply Temperature, °F	120.

ASHRAE 90.1–2019 Incremental Costs

Table 13 provides annual cost savings, added construction costs, and net LCC savings for the mid-rise multifamily prototype building.⁷⁸ Cost estimates typically use current national average prices. Labor costs are based on estimated hours and current crew labor rates from RS Means. In some cases, cost estimates completed for a prior code cycle are still applicable and are adjusted for inflation rather than creating a new cost estimate or obtaining current unit prices throughout the cost estimate. Where cost estimates are updated, inflation factors specific to the equipment are used. These inflation factors are developed for each specific equipment or insulation type by comparing RS Means from the time of the estimate with the current RS Means.

Added construction costs average \$574/building, or just \$18/unit. This low average per-unit increase in cost is because in two of the climate zones analyzed, construction costs are expected to be lower for ASHRAE 90.1–2019 relative to the USDA–HUD 2007 baseline: construction costs for ASHRAE 90.1–2019 are projected to decrease by \$257/unit in Climate Zone 2A, and by \$142/unit in Climate Zone 4A. Conversely, the highest increase is projected to be \$285/unit in Climate Zone 3B, followed by \$274 per unit in Climate Zone 3A. Added or incremental construction cost can be negative for some building types for some of the following reasons:

- Fewer light fixtures are required when the allowed lighting power is reduced. Also, changes from fluorescent to LED technology result in reduced lighting costs in many cases and longer

lamp lives, requiring fewer lamp replacements.

- Smaller heating, ventilating, and air-conditioning (HVAC) equipment sizes can result from the lowering of heating and cooling loads due to other efficiency measures, such as better building envelopes. For example, Standard 90.1–2019 has more stringent fenestration U-factors for some climate zones. This results in smaller equipment and distribution systems, resulting in a negative first cost.⁷⁹

Annual energy cost savings average \$7,153 per building, or \$224 per unit, yielding LCC savings of an estimated \$188,337 per building or \$5,886 per unit. Simple paybacks are immediate in two of the five climate zones analyzed, and 0.4 to 1.5 years in the remaining climate zones, resulting in an extremely fast average payback of just 0.1 years.

TABLE 13—ASHRAE 90.1–2019 ADDED COSTS AND SAVINGS—NATIONAL

[2019 Edition vs. 2007 baseline]

Climate zone	Per square foot			
	Annual cost savings, \$/ft ²	Added construction cost, \$/ft ²	Net LCC savings, \$/ft ²	Simple payback years
2A	0.253	–0.244	6.37	Immediate.
3A	0.213	0.260	5.42	1.2.
3B	0.186	0.270	4.89	1.5.
4A	0.206	–0.135	5.68	Immediate.
5A	0.207	0.075	5.44	0.4.
National Weighted Average	0.212	0.017	5.58	0.1.

⁷⁸ Special tabulation provided by DOE/PNNL to HUD of costs and savings for mid-rise multifamily buildings only, 9/2/21.

⁷⁹ See, for example, PNNL: <https://www.energycodes.gov/sites/default/files/2021-07/>

Cost-effectiveness_of_ASHRAE_Standard_90-1-2019-NorthCarolina.pdf.

Climate zone	Per building			Per unit		
	Annual savings \$/bldg.	Added construction cost, \$/bldg.	Net LCC savings \$/bldg.	Annual savings \$/unit	Added construction cost, \$/unit	Net LCC savings \$/unit
2A	8,536	(8,233)	214,924	267	– 257	6,716
3A	7,187	8,772	182,871	225	274	5,715
3B	6,276	9,110	164,989	196	285	5,156
4A	6,950	(4,555)	191,643	217	– 142	5,989
5A	6,984	2,531	183,546	218	79	5,736
National Weighted Average	7,153	574	188,337	224	18	5,886

State-Level Results

Table 14 provides multifamily added costs and savings for ASHRAE 90.1–19 over the 2007 edition for individual states.⁸⁰ Most states (38 states plus the District of Columbia) show lower per-unit added costs for adoption of

ASHRAE 90.1–2019 compared to the 2007 standard. Incremental cost savings per unit range from a low of \$44 in Illinois to a high of \$425 in Oregon. Only 13 states show increased incremental costs: Alabama, California, Georgia, Mississippi, Montana, North Carolina, Nevada, Oklahoma, South

Carolina, South Dakota, Tennessee, Vermont, Wisconsin. For these 13 states, increased costs average \$169/unit, ranging from \$22/unit in Nevada to \$381/unit in California. The average incremental cost for all states is just \$18/unit.

TABLE 14—ASHRAE 90.1–2019 ADDED COSTS AND SAVINGS—STATES

State	Current code	Incremental cost \$/unit	Energy cost savings \$/bldg./yr	Energy cost savings, \$/unit/yr	Net LCC savings, scenario 1 (publicly-owned), \$/unit	Net LCC savings, scenario 2 (privately-owned), \$/unit	Simple payback (years)
AK	No Code ..	(319)	7,828	245	9,652	8,604	Imme- diate.
AL	2013	210	10,493	328	6,275	5,705	0.9.
AR	2007	(23)	5,736	179	5,321	4,835	Imme- diate.
AZ	Home Rule.	(234)	5,702	178	6,466	5,938	Imme- diate.
CA	2016	381	9,211	288	6,523	6,041	1.6.
CO	No Code ..	(72)	6,208	194	5,630	5,201	Imme- diate.
CT	2010	(122)	7,322	229	8,055	7,423	Imme- diate.
DC	2016	(314)	6,748	211	6,959	6,189	Imme- diate.
DE	2013	(347)	6,208	194	6,537	5,778	Imme- diate.
FL	2013	(127)	5,871	183	6,657	6,039	Imme- diate.
GA	2013	229	9,515	297	5,693	5,213	1.1.
HI	Home Rule.	(297)	5,938	186	11,457	10,357	Imme- diate.
IA	2007	(117)	5,601	175	5,975	5,458	Imme- diate.
ID	2013	(60)	7,592	237	5,135	4,698	Imme- diate.
IL	2013	(44)	8,536	267	6,450	6,028	Imme- diate.
IN	2007	(182)	5,770	180	6,527	5,970	Imme- diate.
KS	No Code ..	(308)	5,972	187	6,655	6,113	Imme- diate.
KY	2007	(328)	9,211	288	5,947	5,377	Imme- diate.
LA	2007	(172)	6,782	212	6,237	5,627	Imme- diate.
MA	2016	(148)	6,208	194	8,424	7,549	Imme- diate.
MD	2013	(303)	5,263	164	6,445	5,848	Imme- diate.
ME	No Code ..	(56)	4,994	156	7,160	6,461	Imme- diate.

⁸⁰ Ibid., DOE/PNNL Special Tabulation provided to HUD 9/2/21.

TABLE 14—ASHRAE 90.1–2019 ADDED COSTS AND SAVINGS—STATES—Continued

State	Current code	Incremental cost \$/unit	Energy cost savings \$/bldg./yr	Energy cost savings, \$/unit/yr	Net LCC savings, scenario 1 (publicly-owned), \$/unit	Net LCC savings, scenario 2 (privately-owned), \$/unit	Simple payback (years)
MI	2013	(88)	6,782	212	6,475	5,978	Imme- diate.
MN	2010	(54)	7,659	239	6,915	6,271	Imme- diate.
MO	No Code ..	(333)	7,457	233	6,434	5,902	Imme- diate.
MS	No Code ..	161	8,199	256	5,985	5,527	0.7.
MT	2013	94	14,744	461	5,620	5,114	0.5.
NC	2010	157	4,859	152	5,125	4,699	0.9.
ND	No Code ..	(57)	6,276	196	6,220	5,584	Imme- diate.
NE	2013	(124)	7,085	221	5,546	5,072	Imme- diate.
NH	2010	(6)	7,018	219	7,022	6,394	Imme- diate.
NJ	2016	(285)	7,254	227	7,477	6,812	Imme- diate.
NM	2013	(305)	7,794	244	5,807	5,300	Imme- diate.
NV	2013	22	6,613	207	5,150	4,758	0.1.
NY	2016	(305)	6,917	216	8,454	7,754	Imme- diate.
OH	2007	(192)	6,984	218	6,151	5,640	Imme- diate.
OK	No Code ..	150	7,389	231	5,330	4,836	0.8.
OR	2016	(425)	6,276	196	5,878	5,421	Imme- diate.
PA	2013	(256)	5,061	158	6,524	5,811	Imme- diate.
PR	2007	0	8,098	253			0.0.
RI	2010	(200)	5,668	177	8,171	7,518	Imme- diate.
SC	2007	186	6,276	196	5,684	5,221	0.9.
SD	No Code ..	297	6,343	198	5,359	4,945	1.6.
TN	2007	118	5,061	158	6,086	5,525	0.5.
TX	2013	(155)	6,276	196	5,581	5,182	Imme- diate.
UT	2013	(104)		0	5,366	4,930	Imme- diate.
VA	2013	(275)	6,006	188	5,297	4,754	Imme- diate.
VT	2016	137	7,187	225	7,341	6,652	0.5.
WA	2016	(432)	8,772	274	5,992	5,481	Imme- diate.
WI	2010	59	5,027	157	6,400	5,909	0.3.
WV	2010	(96)	6,343	198	6,093	5,479	Imme- diate.
WY	No Code ..	(180)	5,736	179	5,952	5,426	Imme- diate.
Average		18	7,153	224	6,394	5,886	0.1

Key: No Code = No statewide code; Home Rule = Home Rule state.

All states show energy cost savings, both those with incremental cost increases as well as those that show lower incremental costs. Annual energy cost savings average \$224/unit, ranging from \$156/unit (Maine) to \$461/unit (Montana). For the prototype 32-unit mid-rise building, this translates into an average annual cost savings of \$7,153/building, ranging from \$4,994 annual cost savings in Maine to \$14,744 in Montana.

The annual energy cost savings relative to lower incremental costs in many states yield “negative” simple paybacks in these states; where that is the case, Table 15 shows these paybacks as “immediate.” Average simple payback for all states is just 0.1 years, or 1.2 months. The states showing lower incremental costs show immediate paybacks: For example, Ohio shows a decrease in first costs of \$192 per unit, but annual energy cost savings of \$218,

in which case the payback on this investment is immediate.

Table 14 also shows life cycle cost savings for this investment. Average Life Cycle Cost savings for privately owned buildings are \$5,886/unit, with LCC savings estimated to be highest in Hawaii (\$10,357 per building) and lowest in North Carolina (\$4,699 per building).

Total Life Cycle Cost Savings

Table 15 shows total estimated LCC Savings for ASHRAE 90.1–2019 relative

to ASHRAE 90.1–2007. For the total estimated units that could be impacted by the adoption of this code, incremental costs will be an estimated

\$1.76 million lower than the cost of construction to the 2007 baseline. Annual energy costs savings are estimated to be \$3.37 million, and

national LCC savings \$90.87 million for privately owned buildings.

TABLE 15—TOTAL LIFE CYCLE SAVINGS—STATES (2020\$)

[ASHRAE 90.1–2019 against 90.1–2007 baseline]

State	Total units	Annual energy cost savings, \$/state	Added construction cost, \$/state	Net LCC savings, scenario 1 (publicly-owned), \$/state	Net LCC savings, scenario 2 (privately-owned), \$/state	Simple payback (years)
AK	56	18,199	(17,731)	535,672	477,505	Immediate.
AL	270	66,046	56,652	1,694,138	1,540,410	0.9.
AR	196	35,042	(4,535)	1,040,340	945,314	Immediate.
AZ	374	87,032	(87,426)	2,415,231	2,217,933	Immediate.
CA	505					
CO	530	94,351	(37,964)	2,981,277	2,754,052	Immediate.
CT	118	33,966	(14,432)	950,540	875,890	Immediate.
DC	96					
DE	50	9,603	(17,171)	323,588	286,010	Immediate.
FL	1,248	319,626	(157,840)	8,305,011	7,534,226	Immediate.
GA	614	129,477	140,483	3,495,238	3,200,678	1.1.
HI	2	922	(595)	22,914	20,714	Immediate.
IA	6	1,164	(702)	35,851	32,751	Immediate.
ID	122	18,523	(7,332)	626,446	573,192	Immediate.
IL	338	66,286	(14,968)	2,179,969	2,037,417	Immediate.
IN	92	20,371	(16,781)	600,445	549,228	Immediate.
KS	59	12,939	(18,165)	392,658	360,683	Immediate.
KY	158	28,987	(51,810)	939,575	849,615	Immediate.
LA	197	44,545	(33,771)	1,225,497	1,105,745	Immediate.
MA	360					
MD	624	128,954	(188,826)	4,021,926	3,648,880	Immediate.
ME	74	17,902	(4,107)	526,279	474,899	Immediate.
MI	130	28,099	(11,377)	841,739	777,180	Immediate.
MN	471	102,798	(25,327)	3,256,772	2,953,840	Immediate.
MO	425	83,348	(141,603)	2,734,363	2,508,516	Immediate.
MS						#DIV/0!
MT	86	15,866	8,023	480,495	437,223	0.5.
NC	935	168,579	146,890	4,792,171	4,393,892	0.9.
ND	25	4,903	(1,423)	155,494	139,599	Immediate.
NE	191	33,430	(23,764)	1,059,288	968,665	Immediate.
NH	152	38,464	(962)	1,067,365	971,847	Immediate.
NJ	134	31,789	(38,147)	1,001,861	912,850	Immediate.
NM	100	17,625	(30,319)	577,846	527,384	Immediate.
NV	281	44,442	6,222	1,447,028	1,337,109	0.1.
NY	1,125	299,968	(342,651)	9,506,499	8,719,231	Immediate.
OH	158	31,319	(30,320)	971,893	891,097	Immediate.
OK	69	12,784	10,256	365,096	331,295	0.8.
OR	154					
PA	126	24,710	(32,283)	822,084	732,143	Immediate.
PR	127					0.0.
RI	42	11,946	(8,314)	339,113	311,984	Immediate.
SC	162	34,333	30,062	920,830	845,845	0.9.
SD	155	28,996	45,938	828,025	764,005	1.6.
TN	613	137,556	72,330	3,727,585	3,384,017	0.5.
TX	4,514	875,739	(699,639)	25,191,762	23,392,691	Immediate.
UT	325	53,375	(33,872)	1,741,174	1,599,869	Immediate.
VA	651	101,587	(179,150)	3,448,464	3,094,969	Immediate.
VT						
WA						
WI	156	33,061	9,211	998,409	921,760	0.3.
WV	62	12,290	(5,949)	377,780	339,669	Immediate.
WY	23	4,123	(4,147)	136,895	124,794	Immediate.
National	17,889	3,365,065	(1,757,336)	99,102,626	90,886,616	Immediate.

The Regulatory Impact Analysis at www.regulations.gov provides a more granular analysis of the estimated cost benefits associated with building to the

ASHRAE 90.1–2019 standard, taking into account each state's current baseline code. Using current state baselines, RIA Figure 28 estimates a

total incremental cost savings of \$10.8 million, and a LCC savings of \$48.1 million (at a 3 percent discount rate).

Incremental Costs and Energy Savings Resulting from Adoption of 2019 ASHRAE 90.1

Current ASHRAE 90.1 Standard	Number of States	Annual Number of Units Affected*	Total Incremental Costs	Net Present Value of Energy Savings	
				3% Discount Rate	7% Discount Rate
No Statewide Code	10	1,596	-\$662,487	\$21,397,225	\$14,072,666
2007	8	1,458	-404,258	6,188,735	4,070,248
2010	6	1,838	-697,586	5,048,570	3,320,376
2013	19	9,569	-8,452,990	14,840,737	9,760,552
2016	2	1,232	-622,624	609,372	400,776
2019	6	1,424	0	0	0
Total	51	17,117	-\$10,839,945	\$48,084,639	\$31,624,618

C. Preliminary Affordability Determination—ASHRAE 90.1–2019

In light of the significant estimated savings, both annual and LCC savings, and the nominal cost increase shown in Tables 13 and 14, HUD and USDA have determined that the adoption of ASHRAE 90.1–2019 will not negatively impact the affordability of the multifamily housing covered by this Notice. As shown in Table 14, the weighted national average incremental cost for adoption of this edition is just \$18/unit, while the annual energy cost savings per unit averages \$224/unit. In all but 13 states, the incremental costs of building to this standard have in fact decreased, not increased, relative to the current HUD–USDA ASHRAE 90.1–2007 standard: in none of these states is the added construction cost more than \$381/unit, and in that state (California), annual energy cost savings are estimated to be \$288/year, yielding a rapid Simple Payback of just 1.6 years. Average (unweighted) payback for all states is 0.1 years (1.2 months), with most states showing an immediate payback due to the lower incremental/first costs. Estimated first costs are also a nominal fraction of total construction costs: the weighted national average of 0.017 \$/sf (less than two cents) in added costs represents just 0.16 percent of the estimated total building cost of \$218/sf. Finally in every state analyzed, the net LCC savings are positive, with a weighted national average of \$5,886 for privately owned buildings.

IV. Impact on Availability of Housing

EISA requires that HUD and USDA assess both the affordability *and* availability of housing covered by the Act. This section of this Notice addresses the impact that the EISA requirements would have on the “availability” of housing covered by the Act. “Affordability” is assumed to be a measure of whether a home built to the updated energy code is affordable to potential homebuyers or renters, while

“availability” of housing is a measure associated with whether builders will make such housing available to consumers at the higher code level; *i.e.*, whether the higher cost per unit as a result of complying with the revised code will impact whether that unit is likely to be built or not. A key aspect of determining the impact on availability is the proportion of affected units in relation to total units funded by HUD and USDA or total for sale units. These issues are discussed below.

2009 IECC—Single Family

In its 2015 Final Determination adopting the 2009 IECC, HUD concluded “[t]hrough both higher construction costs and hedonic increases in demand for more energy-efficient housing are expected to contribute to an increase in housing prices or contract rents, HUD and USDA do not project such higher prices to decrease the quantity of affordable housing exchanged in the market.”⁸¹

The current proposed update of IECC requirements constitutes a more expansive impact. The per unit cost is greater than for the previous rule. PNNL’s estimate of the upfront cost of building to 2021 IECC is approximately \$5,500, ranging from a low upfront incremental cost of \$3,000 in Climate Zone 1 to a high of \$6,800 in Climate Zone 8. Likewise, the geographic scope of the impact of the proposed rule is also more extensive than in 2015. In 2015, construction only in those 16 states that had not yet adopted the 2009 IECC or its equivalent was directly affected. Conversely, only three jurisdictions have adopted the 2021 IECC. Under this Notice, approximately 100,000 newly built units would have to comply with the 2021 IECC standard, compared to an estimate of 10,000 annually for the 2015 notice that required IECC 2009 as a minimum standard. This merits a more detailed discussion of the potential impacts on

the availability of housing to program participants as well as the housing market overall. As set forth in this section of this Notice, HUD and USDA preliminarily find that there would be no noticeable impact on the supply of housing covered by this Notice; there are many ways for both homebuyers and builders to address the costs of the Notice if buying or building to the 2021 IECC is not advantageous; but that, under very specific conditions, availability could be constrained.

The focus of this availability analysis is on the purchase of newly built homes by FHA-insured borrowers. While other covered programs are important, FHA-insured single-family purchases represent the overwhelming majority of units that would be affected by final adoption of the proposed standards. Homebuyers and builders of single-family homes will be more sensitive to the IECC requirement than renters and builders affected by the ASHRAE update because the estimated incremental cost for single-family homes is greater than the incremental cost of updating ASHRAE.

Builder Impacts

Builders are required to build to the 2021 IECC standard only if they wish to sell the new home to a borrower who has a mortgage insured by FHA or guaranteed by USDA. If builders predict that the construction costs outweigh the expected private benefits of building to the 2021 IECC standard, then the supply of newly built homes for FHA-financed borrowers would contract. FHA-insured borrowers would still be able to find housing within the existing housing stock, but their opportunities could be restricted.

One incentive for builders to build to the 2021 IECC standard is to preserve FHA-insured borrowers as potential customers. As shown below, in 2020, FHA-insured loans financed 1 percent of the purchases of newly built homes in the Northeast, 8.3 percent in the Midwest, 11 percent in the West, and

⁸¹ 80 FR 25901 at 25918 (May 6, 2015).

24.5 percent of purchases in the South. FHA-insured borrowers can be a large portion of potential buyers of new construction in some markets.

The regions where construction activity is high (e.g., South and West)

are also areas where a higher share of buyers of new construction are FHA-insured. In such markets, builders would be more inclined to build to the energy code required by this Notice. Having more potential customers

increases competition for a home and would reduce the opportunity costs of time on market.

TABLE 16—TYPE OF FINANCING OF NEW SINGLE-FAMILY HOMES
[Homes sold in the United States, 2020]

	Thousands of homes				Total	Percent financed			
	Conventional	FHA	VA	Cash		Conventional	FHA	VA	Cash
Northeast	25	(Z)	1	2	28	89.3	1.0	3.6	7.1
Midwest	60	6	2	4	72	83.3	8.3	2.8	5.6
South	244	96	31	21	392	62.2	24.5	7.9	5.4
West	128	19	18	8	173	74.0	11.0	10.4	4.6
U.S.	457	122	52	35	665	68.6	18.3	7.8	5.3

Source: Annual Characteristics of New Housing, U.S. Census.
Z = Less than 500 units or less than 0.5 percent.

The cost to a developer of adopting the standard includes the added building costs, loss of potential customers unwilling to pay the additional price, and any other distortions in design introduced by the regulation. The builder can reasonably be expected to build an affordable home to the 2021 IECC standard if: FHA-insured borrowers are a significant part of the market for newly built homes; there is a sufficient market return from energy efficiency; and the builder is able to pass on some of the cost to the buyer. Under these conditions, which will vary by climate zone and the state of the housing market, availability is not likely expected to be adversely affected.

A second possibility is that the builder continues to build affordable homes but not to the 2021 IECC. This would be the case when and where there are significant profits from building new homes for low-income homebuyers, even if not FHA-insured; FHA-insured borrowers are not a major part of the market, perhaps because conventional loans are relatively more affordable; the unlikely case that lower-income homebuyers do not place a significant premium on energy efficiency; or the builder is unable to pass on costs to the buyer. Under this scenario, the total supply of affordable housing would not necessarily be adversely affected, but new construction for FHA borrowers could decline.

A third possibility is that the profit margin from building affordable housing is so slim that any change to the market would lead to a very different development decision. One alternative may be for builders to build housing for higher-income buyers. This strategy could place the home out of reach of FHA-insured borrowers and thus reduce the availability of affordable housing,

albeit not housing for higher-income borrowers.

Single Family Market Impacts

The change in market quantity depends not only on the decisions of builders and the real estate industry more broadly but also on the willingness of buyers to absorb a price change. The percentage reduction of quantity is greater as demand and supply are more responsive to price changes and as the incremental cost constitutes a larger portion of the sales price.

The impact on availability, as measured by the quantity of housing, would be given by:

$$\frac{\Delta Q}{Q} = \left(\frac{E_S \cdot E_D}{E_S - E_D} \right) \cdot \left(\frac{\Delta C}{P} \right)$$

The percentage change in the quantity of housing, $\Delta Q/Q$, depends on the price elasticity of demand E_D (the percentage change in quantity demanded from a percentage change in price), the price elasticity of supply E_S , and the incremental cost ΔC , as a fraction of the pre-regulation sales price P . The percentage reduction of quantity is greater as demand and supply are more responsive to price changes (more price elastic), and the incremental cost constitutes a larger portion of the sales price before the introduction of the cost.⁸²

Estimates from studies of the price elasticities of demand and supply vary due to differences in methods, data, and geographies and time periods examined. Generally, the estimate of the price elasticity of demand for housing is below -1 , as low as -0.2 for low-income households, but has been

estimated to be above -1 . Generally, lower income households have a lower measured price elasticity of demand for housing. The positive association between income and the absolute value of price elasticity stems from shelter being a necessary good.⁸³

The price elasticity of supply and demand has been estimated at a wide variety of levels for different housing markets, primarily due to differences in the ease of building additional units, depending on the metropolitan area, neighborhood and even type of housing.⁸⁴ The incremental cost of adopting the 2021 IECC is expected to be approximately 2 percent of the pre-regulation sales price (a \$5,500 incremental cost and \$250,000 sales price). Our most cautious estimate is that the approximately 2 percent increase in construction cost would reduce the production of homes for FHA-insured borrowers by 1.5 percent, which represents a 0.2 percent reduction of all homes available to FHA-insured homebuyers.

This estimate is considered a “worst-case” scenario because it does not account for any of the positive effects of energy-efficiency. Any adverse impacts on availability would be diminished when there is a perceptible demand for energy-efficient homes.

In addition, there would be no adverse effects on availability if FHA-insured homebuyers were able to find close substitutes in other submarkets. Finding a close substitute may be more difficult in rural areas where there is less available housing stock. USDA

⁸³ Mayo (1981) shows this to be the case when a household must consume a minimum amount of housing (a Stone-Geary utility function).

⁸⁴ Gyourko and Saiz (2006) attribute the local variation in construction activity to more than the cost of materials but also to local wages, local topography, and the local regulatory environment.

⁸² The pass-through rate is the proportion of the cost paid by buyers, which is higher as demand is less price elastic and supply is more price elastic.

guaranteed and direct loans are limited to eligible areas as defined by USDA and exclude central cities. Thus, there could be a greater relative burden on Section 502 guaranteed loans: about half of USDA's guaranteed and direct home loans are to borrowers in rural areas as defined by the 2010 Census as compared to about one-fifth of FHA mortgages (AHS, 2019).

However, adoption of the new code is not expected to have any spillover impacts on other housing submarkets given the relatively small size of the directly affected FHA and USDA submarkets. The purchase of new homes by FHA-insured borrowers represents only 2.3 percent of all residential sales in 2020. As a portion of all home purchases (all homebuyers, new and existing homes), FHA-financed purchases of new construction range from slightly more than 0 percent in the Northeast to slightly less than 3.6 percent in the South.

Energy efficiency has also been shown to impart an economic value to buildings. The willingness to pay for this benefit will vary among homebuyers. If there is a sufficient proportion who expect to realize those gains, then there will be a demand for housing built to the 2021 IECC that could partially counteract any adverse impacts on availability. See the discussions in the Regulatory Impact Analysis at www.regulations.gov in the "Capitalization of Energy Efficiency Standard" section (p.74).

Empirical studies cited in the RIA suggest there is a statistically significant and positive influence of energy efficiency on real estate values.⁸⁵ One study examining the residential market in California found that a green label adds about 2.1 percent to the value of a home. This premium is slightly above

the costs of bringing a home in compliance with the green labels (Energy Star, LEED, and EnergyPoint).

Another study examined the premium placed on the Energy Star certification on homes in Gainesville, Florida and found that there is a premium for these homes but that the premium diminishes when the home is resold; this finding could suggest that energy efficiency is a motivator for buying newly built homes.⁸⁶ Another two studies examined the effects of a label, which would be a voluntary option for the builder, rather than a code, which is obligatory.⁸⁷ In another study, researchers found that energy performance certificates do not play a role in determining market value but that energy efficiency itself is capitalized into housing sales prices (about 2 percent for every 10 percent reduction of energy consumption).⁸⁸

A survey by the National Association of Home Builders found that the median borrower was willing to pay an extra \$5,000 upfront to save \$1000/year in utility bills.⁸⁹ This tradeoff would be equivalent to the resident receiving 10 years of benefits at a 20 percent discount rate or 30 years of benefits at 25 percent discount rate. A recent survey of the National Association of Realtors found that sixty five percent of realtors believed that energy efficiency was valuable in promoting residential units. (However, the majority of realtors (57 percent) were "not sure" as to the impact of energy efficiency on sales price.)⁹⁰

A study of commercial buildings showed that a study with an Energy Star certification will rent for about 3 percent more per square foot and sell for as much as 16 percent more. The authors were able to disentangle the value of the label itself from the value of energy savings stemming from

increased energy efficiency. Energy savings were important: a 10 percent decrease in energy consumption led to an increase in value of about one percent over and above the rent and value premium for a labeled building.⁹¹

All of this empirical research shows that there are profit incentives to providing energy efficiency. Such a price gain would diminish any adverse effects on the supply of housing, although it is also evidence that bidding for energy efficiency could reduce affordability.

Evidence From Prior (2009 IECC) Code Adoption

Examining FHA new construction loans by the level of a state's energy-efficiency standards can provide a rough indicator of the potential impact of the IECC on availability. Having required a minimum standard equal to the 2009 IECC (in 2015), the FHA-insured purchase of new construction could depend on the strictness of the state-wide code relative to the 2009 IECC. However, as shown in Table 17, in states where the state-wide standard is lower than that required by HUD and USDA, the proportion of FHA loans for new construction appears similar to states that have adopted stricter codes. For the group where the state-wide code is at least as stringent as the 2009 IECC, the proportion of FHA-insured new construction loans is 16.9 percent, which is slightly higher than the 15.1 percent for the states where energy codes are below IECC 2009. Despite the cyclical nature of new construction, there is no compelling evidence that the availability of newly built owner-occupied housing will be adversely affected.

TABLE 17—FHA-INSURED SINGLE FAMILY FORWARD LOANS, 2021, GROUPED BY REGION AND STRICTNESS OF STATE-WIDE STANDARD, UNITED STATES

State-wide energy standard	New construction	All purchase loans	Percent new (%)
Less than IECC 2009	14,800	98,300	15.1
Same as IECC 2009	61,900	445,800	13.9
Higher than IECC 2009	47,000	226,700	21.0
South			
Less than IECC 2009	5,400	32,600	16.6

⁸⁵ Laquatra, J., *Housing Market Capitalization of Energy Efficiency Revisited*, 2002.

⁸⁶ Bruegge, C., Deryugina, T. and Myers, E., 2019. The distributional effects of building energy codes. *Journal of the Association of Environmental and Resource Economists*, 6(S1), pp. S95–S127.

⁸⁷ Bruegge et al., 2016; Kahn, Matthew E., and Nils Kok. "The capitalization of green labels in the California housing market." *Regional Science and Urban Economics* 47 (2014): 25–34.

⁸⁸ Aydin, Erdal, Dirk Brounen, and Nils Kok. "The capitalization of energy efficiency: Evidence from the housing market." *Journal of Urban Economics* 117 (2020): 103243.

⁸⁹ Ford, Carmel. "How Much Are Buyers Willing to Pay for Energy Efficiency?" *Eye on Housing: National Association of Home Builders Discusses Economics and Housing Policy*. April 12, 2019. <https://eyeonhousing.org/2019/04/how-much-are-buyers-willing-to-pay-for-energy-efficiency/>.

⁹⁰ National Association of Realtors, REALTORS and Sustainability Report—Residential, 2021, <https://www.nar.realtor/sites/default/files/documents/2021-realtors-and-sustainability-report-04-20-2021.pdf>.

⁹¹ Eichholz, P., N. Kok and J. Quigley, "Doing Well by Doing Good? Green Office Buildings," *American Economic Review* 100:5 (2010): 2492–2509.

TABLE 17—FHA-INSURED SINGLE FAMILY FORWARD LOANS, 2021, GROUPED BY REGION AND STRICTNESS OF STATE-WIDE STANDARD, UNITED STATES—Continued

State-wide energy standard	New construction	All purchase loans	Percent new (%)
Same as IECC 2009	49,390	225,000	21.9
Higher than IECC 2009	37,900	116,000	32.7
West			
Less than IECC 2009	8,090	42,275	19.1
Same as IECC 2009	5,490	32,500	16.9
Higher than IECC 2009	9,050	73,900	12.3
Midwest			
Less than IECC 2009	1,310	23,400	5.6
Same as IECC 2009	5,650	122,000	4.6
Higher than IECC 2009	165	3,270	5.1
Northeast			
Less than IECC 2009	0	0	
Same as IECC 2009	1,410	66,000	2.1
Higher than IECC 2009	500	33,660	1.5

There is some regional variation. In the South, the proportion of new construction is much higher in states above the IECC 2009 (32.7 percent) than in states below (16.6 percent). In the West, the proportion of FHA new construction is lower in states with energy codes above the IECC 2009 (12.3 percent) than in states below (19.1 percent). A clear pattern is not identifiable in either the Northeast or Midwest. Diverse climate zones and housing markets could explain why different regions appear to respond differently to the energy standard.

Variability in Building Practices in Relation to Energy Codes

Note that there is wide variability in enforcement of, or compliance with, building codes in general. Some states do not adopt statewide building codes, others adopt for only certain building types that may exclude single family housing, some states adopt codes with amendments, while others that have adopted building codes may not enforce them, either in their entirety or only for certain building types.⁹²

Conversely, there are a number of above-code energy efficiency or green building standards that meet or exceed the 2021 IECC that a growing number of builders are incorporating as standard building practice. Energy Star for New Homes, historically set at 10 percent above the current state energy code, but

as of January 2023 set at 10 percent over the 2015 IECC across all states, has a new construction adoption rate of nine percent of all single-family homes nationally. There are also a smaller number built to the DOE's Zero Energy Ready Home (ZERH) standards. In addition, certain green building standards set Energy Star as a minimum requirement. With Infrastructure Reduction Act tax credits of \$2,500 now available for Energy Star Certified Homes, and \$5,000 for DOE Zero Energy Ready Homes, the market share for these above-code standards is likely to increase.

There is widespread regional variation in adoption of these standards are not typically mandated by municipalities for single family home construction. There are regional variations in above-code standards among builders as well. For example, for Energy Star New Homes, adoption rates in most states are below five percent, with very little in the northeast, while in the southwest the share of Energy Star new homes is much higher, e.g., Arizona is around 40 percent.⁹³

In the multifamily sector, some builders build to above code standards like LEED, Enterprise Green Communities, ICC 700 National Green Building Standard, PHIUS, the Living Building Challenge or regional programs like Earthcraft. Most of these programs embed Energy Star New Construction within their standards while also addressing other areas of health and disaster resilience requirements. Some

municipalities may require one of these above-code standards for new construction of multifamily housing. In the affordable housing sector, each state may also drive the choice of compliance with above-code standards through their Low-Income Housing Tax Credit Qualified Allocation Plans (QAPs). State QAPs may call out these above-code standards specifically or may allocate points to other matching funding streams that incentivize or require specific above-code standards.

ASHRAE 90.1–2019—Rental Housing

USDA and HUD have preliminarily determined that in light of the extremely small incremental first costs, or, in many cases, negative first costs, adoption of ASHRAE 90.1–2019 will not negatively impact the availability of multifamily units financed or insured through these programs. Simple paybacks times are extremely low for the small number of states that will see an increase in first costs, in most cases less than one year. The estimate of the direct cost of construction of moving to this code is not greater than zero. Even if there were a slight increase in construction costs, the estimates of energy savings are sizeable enough such that the benefits would offset the costs for property managers. There could be some builders of multi-family properties who are doubtful of the return and so view the ASHRAE 90.1–2019 requirement as a net burden. For the hesitant developer, there remain other incentives to comply: FHA multifamily loans allow a higher LTV than is common and Low-Income Housing Tax Credits that are frequently used by

⁹² Lawrence Berkeley National Laboratory, *The Cost of Enforcing Building Codes, Phase I*, April 2013. Table 1 shows varying compliance rates: https://www.researchgate.net/publication/282136731_The_Cost_of_Enforcing_Building_Energy_Codes_Phase_1.

⁹³ https://www.energystar.gov/newhomes/energy_star_certified_new_homes_market_share.

developers in conjunction with HUD financing often carry a requirement or incentive for energy efficiency. In addition, FHA's lower Green Mortgage Insurance Premium provides a strong incentive for developers to adopt an above-code standard.

V. Implementation

Section 109(d) of Cranston-Gonzalez (42 U.S.C. 12709) automatically applies to all covered programs upon completion and publication of the specified affordability and availability determinations by HUD and USDA. Accordingly, once a Final Determination has been made by HUD and USDA under section 109(d) (42 U.S.C. 12709(d)) and published, additional notice and comment rulemaking will not be required for the covered programs. The new codes, if found not to negatively affect both the availability and affordability of covered housing, will automatically apply, subject to administrative actions such as mortgagee letters, notices, or amendments to handbooks and conforming regulations that may be required by individual programs.

Based on DOE findings on improvements in energy efficiency and energy savings, and a subsequent HUD and USDA Final Determination with respect to both housing affordability and availability, HUD and USDA programs specified under EISA will implement procedures to ensure that recipients of HUD and USDA funding, assistance, or insurance comply with the 2021 IECC and ASHRAE 90.1–2019 code requirements, commencing no later than 30 days after the date of publication of a Notice of Final Determination. HUD and USDA will take such administrative actions as are necessary to ensure timely implementation of and compliance with the energy codes, to include Mortgagee Letters, Notices, Notices of Funding Opportunity (NOFOs), Builder's Certification Form HUD–92541, and amendments to relevant handbooks. Conforming rulemaking will be required to update FHA's single family minimum property standards at 24 CFR 200.926d, Public Housing Capital Fund energy standards at 24 CFR 905, and HOME property standards at 24 CFR 92.251, though as noted above, this would not entail notice and comment rulemaking. USDA will update minimum energy requirements at 7 CFR part 1924.

To enable these administrative and conforming rulemaking procedures to be implemented and to provide the industry with adequate time to prepare for these requirements and incorporate them in project plans and specifications, proposals or applications, adoption of

the new construction standards described in this Notice will take effect as follows:

(1) For FHA-insured multifamily programs, the standards set forth by this Notice are applicable to those properties for which mortgage insurance pre-applications are received by HUD 90 days after the effective date of this Final Determination;

(2) For FHA-insured and USDA-guaranteed single family loan programs, the standards set forth by this Notice are applicable to properties for which building permits are issued 180 days after the effective date of a Final Determination.

(3) For the HOME program, the standards set forth by this Notice are applicable to residential new construction projects for which HOME funds applications are committed by Participating Jurisdictions no later than 180 days after the effective date of a Final Determination.

(4) For Public Housing Capital Fund new construction projects for which approvals are submitted the standards set forth by this Notice are applicable no later than 180 days after the effective date of a Final Determination.

Alternate Compliance Paths

HUD and USDA will accept certain energy and green building certifications as evidence of compliance with the standards addressed in this Notice, provided that they require energy efficiency levels that meet or exceed the 2021 IECC or ASHRAE 90.1–2019. These may include standards referenced in one or more HUD or USDA programs, such as the ICC–700 National Green Building Standard, Enterprise Green Communities, Energy Star Certified New Homes, Energy Star Indoor Air Plus, DOE Zero Energy Ready Homes, Leadership in Energy and Environmental Design (LEED), Living Building Challenge or Passive House, as well as one or more regional or local standards such as Earthcraft, Earth Advantage, or Greenpoint Rated New Home.⁹⁴ HUD and USDA will publish a list of those standards that comply with the minimum energy efficiency requirements of this Notice. HUD and USDA will also accept certifications of compliance of state or local codes or standards for which credible third-party documentation exists that these meet or exceed the 2021 IECC and ASHRAE 90.1–2019.

⁹⁴ Energy Star Certified New Homes Version 3.2 and DOE's Zero Energy Ready Homes set the 2021 IECC as the baseline standard.

VI. Request for Public Comment

HUD and USDA welcome comments on all aspects of this Preliminary Determination, but are especially interested in comments on the following subjects:

(1) HUD and USDA are requesting comments on whether the higher first-costs associated with adopting the 2021 IECC over the current 2009 IECC standard for USDA- or HUD-assisted housing, or relative to the most recent 2018 IECC, may lower homebuyer options, despite the significant life-cycle cost savings over the life of the mortgage described in this Notice, *i.e.*, whether adoption of the 2021 IECC may limit the availability of such housing to otherwise-qualified buyers or renters.

(2) HUD and USDA request comments from code officials on the current status of code adoption in their states, and the anticipated timetable for adopting the next revision of the IECC and/or ASHRAE codes, their equivalent, or higher, as well as from code officials in home rule jurisdictions that may adopt the codes independently of state action. HUD and USDA wish to establish the extent to which adoption of the latest IECC and ASHRAE 90.1 standards aligns with state or local home rule adoption of these codes.

(3) HUD and USDA request comments on the cost benefit analysis utilized by PNNL as described in Sections II.B and III.B of this Preliminary Determination.

(4) Anecdotal reports suggest that because manually operated bathroom fans allowed under the IECC to meet ventilation requirements rely on occupant action to operate them, these may impact indoor air quality and the health of occupants. HUD and USDA request comments on this possible health concern.

(5) HUD and USDA are requesting comment on the extent to which the 2021 IECC air leakage requirements (3 air changes per hour or 5 air changes per hour at 50 pascals depending on Climate Zone) may present fire code issues for attached single family homes or low-rise multifamily properties, and, if such issues exist, cost-effective solutions that have been developed in the field or are currently being developed to address them.

(6) HUD and USDA seek comment on the time required for builders and building designers to familiarize themselves with the new codes, the training or technical support that may be required by building professionals and local code officials on the new requirements of the 2021 IECC and ASHRAE 90.1–2019 standards, workforce training needs, and any other

issues related to implementation of these standards. Comments on particular challenges or issues facing rural areas in adoption and/or implementation of these codes are also requested.

(7) The construction industry has experienced COVID-related supply chain challenges for certain products and materials, particularly but not exclusively for lumber products, leading to significant price increases in such products as framing lumber, plywood, and oriented strand board (OSB).⁹⁵ HUD and USDA solicit comments on the duration, persistence and intensity of these price increases, the extent to which they may impact the cost of energy related products or materials covered by the IECC or ASHRAE energy codes addressed in this Notice, and to what extent these supply chain issues may impact implementation of the codes addressed by this Notice.

(8) HUD and USDA currently provide incentives or require green building standards for some programs. The agencies are seeking to maximize alignment between the 2021 IECC and ASHRAE 90.1–2019 and those green building standards that are encouraged or incentivized through these programs. During the implementation phase of this Notice, HUD and USDA will seek certifications from all green building or above-code energy performance standard-setting bodies as to their establishing 2021 IECC and ASHRAE 90.1–2019 standards as the baseline against which they measure above-code energy performance. The agencies seek preliminary comments from current green building or above-code energy performance standard-setting bodies on their (1) current minimum IECC and ASHRAE 90.1 requirements; and/or (2) proposed establishment of the 2021 IECC and ASHRAE 90.1–2019 as the baseline for such standards.

VII. Environmental Impact

A Finding of No Significant Impact with respect to the environment has been made in accordance with HUD regulations at 24 CFR part 50 and USDA Rural Development regulations at 7 CFR part 1970, which implement section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)). That finding is posted at www.regulations.gov and is also available for public inspection between the hours of 8 a.m. and 5 p.m. weekdays in the Regulations Division, Office of

General Counsel, Department of Housing and Urban Development, 451 7th Street SW, Room 10276, Washington, DC 20410–0500. Due to security measures at the HUD Headquarters building, please schedule an appointment to review the finding by calling the Regulations Division at 202–402–3055 (this is not a toll-free number). HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech or communication disabilities. To learn more about how to make an accessible telephone call, please visit <https://www.fcc.gov/consumers/guides/telecommunications-relay-service-trs>.

Adrianne Todman,

Deputy Secretary, U.S. Department of Housing and Urban Development.

Anthony Shea,

Acting Deputy Secretary, U.S. Department of Agriculture.

[FR Doc. 2023–10596 Filed 5–17–23; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R4–ES–2023–N042;
FXES11140400000–234–FF04E000000]

Endangered Species; Recovery Permit Applications

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of permit applications; request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service, have received applications for permits to conduct activities intended to enhance the propagation or survival of endangered species under the Endangered Species Act. We invite the public and local, State, Tribal, and Federal agencies to comment on these applications. Before issuing any of the requested permits, we will take into consideration any information that we receive during the public comment period.

DATES: We must receive written data or comments on the applications by June 20, 2023.

ADDRESSES:

Reviewing Documents: Submit requests for copies of applications and other information submitted with the applications to Karen Marlowe (see **FOR FURTHER INFORMATION CONTACT**). All requests and comments should specify the applicant name and application number (e.g., Mary Smith, ESPER0001234).

Submitting Comments: If you wish to comment, you may submit comments by one of the following methods:

- *Email (preferred method):*

permitsR4ES@fws.gov. Please include your name and return address in your email message. If you do not receive a confirmation from the U.S. Fish and Wildlife Service that we have received your email message, contact us directly at the telephone number listed in **FOR FURTHER INFORMATION CONTACT**.

- *U.S. mail:* U.S. Fish and Wildlife Service Regional Office, Ecological Services, 1875 Century Boulevard, Atlanta, GA 30345 (Attn: Karen Marlowe, Permit Coordinator).

FOR FURTHER INFORMATION CONTACT:

Karen Marlowe, Permit Coordinator, 404–679–7097 (telephone) or karen_marlowe@fws.gov (email). 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: We, the U.S. Fish and Wildlife Service, invite review and comment from the public and local, State, Tribal, and Federal agencies on applications we have received for permits to conduct certain activities with endangered and threatened species under section 10(a)(1)(A) of the Endangered Species Act of 1973, as amended (ESA; 16 U.S.C. 1531 *et seq.*), and our regulations in the Code of Federal Regulations (CFR) at 50 CFR part 17. Documents and other information submitted with the applications are available for review, subject to the requirements of the Privacy Act of 1974, as amended (5 U.S.C. 552a) and the Freedom of Information Act (5 U.S.C. 552).

Background

With some exceptions, the ESA prohibits take of listed species unless a Federal permit is issued that authorizes such take. The ESA's definition of "take" includes hunting, shooting, harming, wounding, or killing, and also such activities as pursuing, harassing, trapping, capturing, or collecting.

A recovery permit issued by us under section 10(a)(1)(A) of the ESA authorizes the permittee to take endangered or threatened species while engaging in activities that are conducted for scientific purposes that promote recovery of species or for enhancement of propagation or survival of species.

⁹⁵ Softwood lumber prices in North America, <https://www.nrcan.gc.ca/our-natural-resources/domestic-and-international-markets/current-lumber-pulp-panel-prices/13309#panel>.

These activities often include the capture and collection of species, which would result in prohibited take if a permit were not issued. Our regulations implementing section 10(a)(1)(A) for these permits are found at 50 CFR 17.22 for endangered wildlife species, 50 CFR 17.32 for threatened wildlife species, 50 CFR 17.62 for endangered plant species,

and 50 CFR 17.72 for threatened plant species.

Permit Applications Available for Review and Comment

The ESA requires that we invite public comment before issuing these permits. Accordingly, we invite local, State, Tribal, and Federal agencies, and the public to submit written data, views,

or arguments with respect to these applications. The comments and recommendations that will be most useful and likely to influence agency decisions are those supported by quantitative information or studies. Proposed activities in the following permit requests are for the recovery and enhancement of propagation or survival of the species in the wild.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
PER0018443-0	U.S. Army Engineer Research and Development Center; Vicksburg, MS.	Fishes: Alabama sturgeon (<i>Scaphirhynchus suttkusi</i>), Arkansas River shiner (<i>Notropis girardi</i>), Big Bend gambusia (<i>Gambusia gaigei</i>), Clear Creek gambusia (<i>Gambusia heterochir</i>), Comanche Springs pupfish (<i>Cyprinodon elegans</i>), Devils River minnow (<i>Dionda diabolii</i>), duskytail darter (<i>Etheostoma percnurum</i>), fountain darter (<i>Etheostoma fonticola</i>), Leon Springs pupfish (<i>Cyprinodon bovinus</i>), Neosho madtom (<i>Noturus placidus</i>), pearl darter (<i>Percina aurora</i>), Pecos bluntnose shiner (<i>Notropis simus pecosensis</i>), Pecos gambusia (<i>Gambusia nobilis</i>), peppered chub (<i>Macrhybopsis tetranema</i>), Rio Grande silvery minnow (<i>Hybognathus amarus</i>), San Marcos gambusia (<i>Gambusia georgei</i>), sharpnose shiner (<i>Notropis oxyrhynchus</i>), smalleye shiner (<i>Notropis buccula</i>), Topeka shiner (<i>Notropis topeka</i> [= <i>tristis</i>]), and yellowcheek darter (<i>Etheostoma moorei</i>); Mussels: Alabama lampmussel (<i>Lampsilis virescens</i>), Alabama moccasinshell (<i>Medionidus acutissimus</i>), Arkansas fatmucket (<i>Lampsilis powellii</i>), black clubshell (<i>Pleurobema curtum</i>), clubshell (<i>Pleurobema clava</i>), Cumberlandian combshell (<i>Epioblasma brevidans</i>), Curtis pearlymussel (<i>Epioblasma florentina curtisii</i>), false spike (<i>Fusconaia mitchelli</i>), fanshell (<i>Cyprogenia stegaria</i>), finereyed pigtoe (<i>Fusconaia cuneolus</i>), flat pigtoe (<i>Pleurobema marshalli</i>), Guadalupe fatmucket (<i>Lampsilis bergmanni</i>), Guadalupe orb (<i>Cyclonaias necki</i>), heavy pigtoe (<i>Pleurobema taitianum</i>), Higgins eye (<i>Lampsilis higginsii</i>), longsolid (<i>Fusconaia subrotunda</i>), Louisiana pearlshell (<i>Margaritifera hembeli</i>), Neosho mucket (<i>Lampsilis rafinesqueana</i>), northern riffleshell (<i>Epioblasma rangiana</i>), orangenacre mucket (<i>Hamiota perovalis</i>), Ouachita rock pocketbook (<i>Arcidens wheeleri</i>), ovate clubshell (<i>Pleurobema perovatum</i>), round hickorynut (<i>Obovaria subrotunda</i>), scaleshell (<i>Leptodea leptodon</i>), slabside pearlymussel (<i>Pleurobema dolabelloides</i>), snuffbox (<i>Epioblasma triquetra</i>), southern clubshell (<i>Pleurobema decisum</i>), southern combshell (<i>Epioblasma penita</i>), speckled pocketbook (<i>Lampsilis streckeri</i>), spectaclecase (<i>Cumberlandia monodonta</i>), stirrupshell (<i>Quadrula stapes</i>), Texas fatmucket (<i>Lampsilis bracteata</i>), Texas fawnfoot (<i>Truncilla macrodon</i>), Texas hornshell (<i>Popenaias popeii</i>), Texas pimpleback (<i>Cyclonaias petrina</i>), turgid blossom (<i>Epioblasma turgidula</i>), and winged mapleleaf (<i>Quadrula fragosa</i>); Insects: American burying beetle (<i>Nicrophorus americanus</i>).	Alabama, Arkansas, Florida, Illinois, Indiana, Kentucky, Louisiana, Mississippi, Missouri, Ohio, Tennessee, Texas, and West Virginia.	Presence/probable absence surveys and scientific studies.	Capture, handle, identify, collect glochidia, and release.	New.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
ES91373A-4 ...	Jonathan Miller; Brundidge, AL.	Alabama lampmussel (<i>Lampsilis virescens</i>), Alabama moccasinshell (<i>Medionidus acutissimus</i>), Alabama pearlshell (<i>Margaritifera marrianae</i>), black clubshell (<i>Pleurobema curtum</i>), Chipola slabshell (<i>Elliptio chipolaensis</i>), Choctaw bean (<i>Obovaria choctawensis</i>), Coosa moccasinshell (<i>Medionidus parvulus</i>), cracking pearlymussel (<i>Hemistena lata</i>), Cumberlandian combshell (<i>Epioblasma brevidens</i>), dark pigtoe (<i>Pleurobema furvum</i>), dromedary pearlymussel (<i>Dromus dromas</i>), fanshell (<i>Cyprogenia stegaria</i>), fat pocketbook (<i>Potamilus capax</i>), fat threeeridge mussel (<i>Amblema neislerii</i>), finelined pocketbook (<i>Hamiota altilis</i>), finerayed pigtoe (<i>Fusconaia cuneolus</i>), fluted kidneyshell (<i>Ptychobranchus subtentus</i>), fuzzy pigtoe (<i>Pleurobema strodeanum</i>), Georgia pigtoe (<i>Pleurobema hanleyianum</i>), Gulf moccasinshell (<i>Medionidus penicillatus</i>), heavy pigtoe (<i>Pleurobema taitianum</i>), inflated heelsplitter (<i>Potamilus inflatus</i>), Louisiana pearlshell (<i>Margaritifera hembeli</i>), narrow pigtoe (<i>Fusconaia escambia</i>), orangenacre mucket (<i>Hamiota perovalis</i>), oval pigtoe (<i>Pleurobema pyriforme</i>), ovate clubshell (<i>Pleurobema perovatum</i>), pink mucket (<i>Lampsilis abrupta</i>), purple bankclimber (<i>Elliptioideus sloatianus</i>), rabbitsfoot (<i>Quadrula cylindrica cylindrica</i>), ring pink (<i>Obovaria retusa</i>), rough pigtoe (<i>Pleurobema plenum</i>), round ebonyshell (<i>Reginaia rotulata</i>), sheepnose (<i>Plethobasus cyphyus</i>), shiny pigtoe (<i>Fusconaia cor</i>), shinyrayed pocketbook (<i>Hamiota subangulata</i>), slabside pearlymussel (<i>Pleuronaia dolabelloides</i>), snuffbox (<i>Epioblasma triquetra</i>), southern clubshell (<i>Pleurobema decusum</i>), southern kidneyshell (<i>Ptychobranchus jonesi</i>), southern pigtoe (<i>Pleurobema georgianum</i>), southern sandshell (<i>Hamiota australis</i>), tapered pigtoe (<i>Fusconaia burkei</i>), and triangular kidneyshell (<i>Ptychobranchus greenii</i>).	Alabama, Florida, Georgia, Louisiana, and Mississippi.	Presence/probable absence surveys.	Capture, handle, identify, release, and salvage relic shells.	Renewal.
ES56749B-5 ...	Patrick Moore; Johnson City, TN.	Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), Ozark big-eared bat (<i>Corynorhinus townsendii ingens</i>), tricolored bat (<i>Perimyotis subflavus</i>), and Virginia big-eared bat (<i>Corynorhinus townsendii virginianus</i>).	Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, Wisconsin, and Wyoming.	Presence/probable absence surveys, studies to document habitat use, population monitoring, and studies to evaluate potential impacts of white-nose syndrome or other threats.	Enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, radio tag, and release.	Renewal and amendment.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
ES070800-7	Ecological Solutions, Inc.; Roswell, GA.	Fishes: amber darter (<i>Percina antesella</i>), blue shiner (<i>Cyprinella caerulea</i>), Cherokee darter (<i>Etheostoma scotti</i>), Conasauga logperch (<i>Percina jenkinsi</i>), Etowah darter (<i>Etheostoma etowahae</i>), goldline darter (<i>Percina aurolineata</i>), rush darter (<i>Etheostoma phytophilum</i>), snail darter (<i>Percina tanasi</i>), spring pygmy sunfish (<i>Elassoma alabamae</i>), and vermilion darter (<i>Etheostoma chermocki</i>); Mussels: Alabama moccasinshell (<i>Medionidus acutissimus</i>), Alabama pearlshell (<i>Margaritifera marrianae</i>), Altamaha spiny mussel (<i>Elliptio spinosa</i>), Chipola slabshell (<i>Elliptio chipolaensis</i>), Choctaw bean (<i>Obovaria choctawensis</i>), Coosa moccasinshell (<i>Medionidus parvulus</i>), Cumberland bean (<i>Villosa trabalis</i>), fat threeridge (<i>Amblema neisleri</i>), finelined pocketbook (<i>Hamiota altis</i>), fuzzy pigtoe (<i>Pleurobema strodeanum</i>), Georgia pigtoe (<i>Pleurobema hanleyianum</i>), Gulf moccasinshell (<i>Medionidus penicillatus</i>), narrow pigtoe (<i>Fusconaia escambia</i>), Ochlockonee moccasinshell (<i>Medionidus simpsonianus</i>), orangenacre mucket (<i>Hamiota perovalis</i>), oval pigtoe (<i>Pleurobema pyriforme</i>), ovate clubshell (<i>Pleurobema perovatum</i>), purple bankclimber (<i>Elliptioideus sloatianus</i>), rabbitsfoot (<i>Quadrula cylindrica cylindrica</i>), round ebonyshell (<i>Reginaia rotulata</i>), sheepnose (<i>Plethobasus cyphus</i>), shinyrayed pocketbook (<i>Hamiota subangulata</i>), slabside pearly mussel (<i>Pleuonaia dolabelloides</i>), snuffbox (<i>Epioblasma triquetra</i>), southern acornshell (<i>Epioblasma othcaloogenis</i>), southern clubshell (<i>Pleurobema decusum</i>), southern combshell (<i>Epioblasma penita</i>), southern kidneyshell (<i>Ptychobranthus jonesi</i>), southern pigtoe (<i>Pleurobema georgianum</i>), southern sandshell (<i>Hamiota australis</i>), spectaclecase (<i>Cumberlandia monodonta</i>), tapered pigtoe (<i>Fusconaia burkei</i>), triangular kidneyshell (<i>Ptychobranthus greenii</i>), and upland combshell (<i>Epioblasma metastrata</i>).	Alabama, Florida, Georgia, North Carolina, and Tennessee.	Presence/probable absence surveys.	Capture, handle, identify, and release.	Renewal.
ES070796-12 ..	Apogee Environmental & Archaeological, Inc.; Pittsburgh, PA.	Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), Ozark big-eared bat (<i>Corynorhinus townsendii ingens</i>), and Virginia big-eared bat (<i>Corynorhinus townsendii virginianus</i>).	Alabama, Arkansas, Connecticut, Delaware, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Mississippi, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Virginia, Vermont, West Virginia, Wisconsin, and Wyoming.	Presence/probable absence surveys, studies to document habitat use, population monitoring, and studies to evaluate potential impacts of white-nose syndrome or other threats.	Enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, radio tag, and release.	Renewal.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
ES129703-7	HMB Professional Engineers, Inc.; Frankfort, KY.	Bats: gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), tricolored bat (<i>Perimyotis subflavus</i>), and Virginia big-eared bat (<i>Corynorhinus townsendii virginianus</i>); Fishes: amber darter (<i>Percina antesella</i>), blackside dace, (<i>Phoxinus cumberlandensis</i>), blue shiner (<i>Cyprinella caerulea</i>), bluemask darter (<i>Etheostoma akatulo</i>), boulder darter (<i>Etheostoma wapiti</i>), Conasauga logperch (<i>Percina jenkinsi</i>), Cumberland darter (<i>Etheostoma susanae</i>), diamond darter (<i>Crystallaria cincotta</i>), duskytail darter (<i>Etheostoma percnurum</i>), Kentucky arrow darter (<i>Etheostoma spilotum</i>), palezone shiner (<i>Notropis albizonatus</i>), pygmy madtom (<i>Noturus stanauli</i>), relict darter (<i>Etheostoma chienense</i>), and smoky madtom (<i>Noturus baileyi</i>); Mussels: Alabama lampmussel (<i>Lampsilis virescens</i>), Appalachian elktoe (<i>Alasmodonta raveneliana</i>), Appalachian monkeyface (<i>Thelidderma sparsa</i>), birdwing pearlymussel (<i>Lemiox rimosus</i>), clubshell (<i>Pleurobema clava</i>), Coosa moccasinshell (<i>Medionidus parvulus</i>), cracking pearlymussel (<i>Hemistena lata</i>), Cumberland bean (<i>Villosa trabalis</i>), Cumberland elktoe (<i>Alasmodonta atropurpurea</i>), Cumberland monkeyface (<i>Thelidderma intermedia</i>), Cumberland pigtoe (<i>Pleuroaia gibber</i>), Cumberlandian combshell (<i>Epioblasma brevidans</i>), dromedary pearlymussel (<i>Dromus dromas</i>), fanshell (<i>Cyprogenia stegaria</i>), fat pocketbook (<i>Potamilus capax</i>), finereyed pigtoe (<i>Fusconaia cuneolus</i>), fluted kidneyshell (<i>Ptychobranhus subtentus</i>) green blossom (<i>Epioblasma torulosa gubernaculum</i>), littlewing pearlymussel (<i>Pegias fabula</i>), longsolid (<i>Fusconaia subrotunda</i>), northern riffleshell (<i>Epioblasma rangiana</i>), orangefoot pimpleback (pearlymussel) (<i>Plethobasus cooperianus</i>), oyster mussel (<i>Epioblasma capsaeformis</i>), pale lilliput (<i>Toxolasma cylindrellus</i>), pink mucket (<i>Lampsilis abrupta</i>), purple bean (<i>Villosa perpurpurea</i>), purple cat's paw (<i>Epioblasma obliquata obliquata</i>), rabbitsfoot (<i>Quadrula cylindrica cylindrica</i>), ring pink (<i>Obovaria retusa</i>), rough pigtoe (<i>Pleurobema plenum</i>), rough rabbitsfoot (<i>Quadrula cylindrica strigillata</i>), round hickorynut (<i>Obovaria subrotunda</i>), sheepnose (<i>Plethobasus cyphyus</i>), shiny pigtoe (<i>Fusconaia cor</i>), slabside pearlymussel (<i>Pleuroaia dolabelloides</i>), snuffbox (<i>Epioblasma triquetra</i>), southern acornshell (<i>Epioblasma othcaloogensis</i>), southern pigtoe (<i>Pleurobema georgianum</i>), spectaclecase (<i>Cumberlandia monodonta</i>), tan riffleshell (<i>Epioblasma florentina walker</i> [= <i>E. walker</i>]), triangular kidneyshell (<i>Ptychobranhus greenii</i>), turgid blossom (<i>Epioblasma turgidula</i>), upland combshell (<i>Epioblasma metastriata</i>), white wartyback (<i>Plethobasus cicatricosus</i>), winged mapleleaf (<i>Quadrula fragosa</i>), and yellow blossom (<i>Epioblasma florentina florentina</i>); Crustacean: Big Sandy crayfish (<i>Cambarus callainus</i>).	Alabama, Georgia, Indiana, Kentucky, North Carolina, Ohio, Tennessee, and West Virginia.	Presence/probable absence surveys, studies to document habitat use, and population monitoring.	Bats: enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, radio tag, and release; Fishes and Crustacean: capture, handle, identify, and release; Mussels: capture, handle, identify, release, and salvage relic shells.	Renewal and amendment.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
ES171545-4 ...	Ronald Redman; Benton, AR.	Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), Ozark big-eared bat (<i>Corynorhinus townsendii ingens</i>), and Virginia big-eared bat (<i>Corynorhinus townsendii virginianus</i>).	Alabama, Arkansas, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.	Presence/probable absence surveys and white-nose syndrome research.	Enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, radio tag, swab, and release.	Renewal.
ES71854A-1 ...	David Eargle; Columbia, SC.	Carolina heelsplitter (<i>Lasmigona decorata</i>)	North Carolina and South Carolina.	Presence/probable absence surveys.	Capture, handle, identify, release, and salvage relic shells.	Renewal.
PER1922058-0	Tracy Feltman; Chatsworth, GA.	Fishes: amber darter (<i>Percina antesella</i>), blue shiner (<i>Cyprinella caerulea</i>), Cherokee darter (<i>Etheostoma scotti</i>), Conasauga logperch (<i>Percina jenkinsi</i>), Etowah darter (<i>Etheostoma etowahae</i>), frecklebelly madtom (<i>Noturus munitus</i>), goldline darter (<i>Percina aurolineata</i>), and trispot darter (<i>Etheostoma trisella</i>); Mussels: Alabama moccasinshell (<i>Medionidus acutissimus</i>), Coosa moccasinshell (<i>Medionidus parvulus</i>), fat threeridge (<i>Amblema neislerii</i>), finelined pocketbook (<i>Hamiota altilis</i>), purple bankclimber (<i>Elliptioideus sloatianus</i>), shinyrayed pocketbook (<i>Hamiota subangulata</i>), and southern acornshell (<i>Epioblasma othcaloogenis</i>).	Georgia	Presence/probable absence surveys.	Capture, handle, identify, and release.	New.
ES63577A-3 ...	Mammoth Cave National Park; Mammoth Cave, KY.	Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), and tricolored bat (<i>Perimyotis subflavus</i>).	Alabama, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia.	Presence/probable absence surveys, studies to document habitat use, disease surveillance activities, and population monitoring.	Enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, radio tag, collect hair samples, PIT tag, light tag, wing punch, and release.	Renewal and amendment.
ES37900B-2 ...	Sarah Lauerman; Gainesville, FL.	Red-cockaded woodpecker (<i>Picoides borealis</i>)	Osceola National Forest, Florida.	Population monitoring and translocation of subadults from Osceola National Forest (donor population) to recruitment clusters.	Capture, handle, band, monitor nest cavities, and translocate.	Renewal.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
ES53149B-3 ...	Hans William Otto; Tucson, AZ.	Mammals: Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), Ozark big-eared bat (<i>Corynorhinus townsendii ingens</i>), and Virginia big-eared bat (<i>Corynorhinus townsendii virginianus</i>); Mice: New Mexico meadow jumping mouse (<i>Zapus hudsonius luteus</i>).	Alabama, Arizona, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, Wisconsin, and Wyoming.	Presence/probable absence surveys and scientific research.	Bats: enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, collect hair samples, band, radio tag, light tag, collect fecal material, apply fungal lift tape, swab, wing punch, and release; Mice: live trap, handle, identify, and release.	Renewal.
ES142294-6	William Holiman; Little Rock, AR.	Red-cockaded woodpecker (<i>Picoides borealis</i>)	Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, Oklahoma, South Carolina, and Texas.	Population management and monitoring.	Capture, band, construct and monitor artificial nest cavities and restrictors, translocate, recapture, and release.	Renewal.
ES066980-6	Brandon Rutledge; Newton, GA.	Red-cockaded woodpecker (<i>Picoides borealis</i>)	Georgia	Population management and monitoring.	Capture, band, construct and monitor artificial nest cavities and restrictors, translocate, recapture, buccal swab, and release.	Renewal.
PER2378263-0	Anthony Ledbetter; Clyde, NC.	Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), northern long-eared bat (<i>Myotis septentrionalis</i>), and tricolored bat (<i>Perimyotis subflavus</i>).	Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.	Presence/probable absence surveys.	Enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, radio tag, and release.	New.

Permit application No.	Applicant	Species	Location	Activity	Type of take	Permit action
ES63633A-7 ...	Biodiversity Research Institute; Portland, ME.	Gray bat (<i>Myotis grisescens</i>), Indiana bat (<i>Myotis sodalis</i>), and northern long-eared bat (<i>Myotis septentrionalis</i>).	Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Vermont, Virginia, West Virginia, Wisconsin, and Wyoming.	Presence/probable absence surveys, studies to document habitat use, population monitoring, and studies to evaluate potential impacts of white-nose syndrome or other threats.	Enter hibernacula or maternity roost caves, capture with mist nets or harp traps, handle, identify, band, collect hair samples, radio tag, wing punch, and release.	Renewal.
ES034476-5	Florida Forest Service; Milton, FL.	Red-cockaded woodpecker (<i>Picoides borealis</i>)	Florida	Population management and monitoring.	Install artificial nest cavities and restrictors, monitor nest cavities, capture, band, translocate, and release.	Renewal.
PER2417230-0	Zachariah Alley; Cincinnati, OH.	Amber darter (<i>Percina antesella</i>), blackside dace (<i>Phoxinus phoxinus</i>), blue shiner (<i>Cyprinella caerulea</i>), candy darter (<i>Etheostoma osburni</i>), Carolina madtom (<i>Noturus furiosus</i>), Cherokee darter (<i>Etheostoma scotti</i>), chucky madtom (<i>Noturus crypticus</i>), Conasauga logperch (<i>Percina jenkinsi</i>), Cumberland darter (<i>Etheostoma susanae</i>), diamond darter (<i>Crystallaria cincotta</i>), Etowah darter (<i>Etheostoma etowahae</i>), frecklebelly madtom (<i>Noturus munitus</i>), goldline darter (<i>Percina aurolineata</i>), Kentucky arrow darter (<i>Etheostoma spilatum</i>), laurel dace (<i>Chrosomus saylori</i>), pallid sturgeon (<i>Scaphirhynchus albus</i>), relict darter (<i>Etheostoma chienense</i>), Roanoke logperch (<i>Percina rex</i>), smoky madtom (<i>Noturus baileyi</i>), and trispot darter (<i>Etheostoma trisella</i>).	Alabama, Arkansas, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, North Carolina, North Dakota, South Dakota, Tennessee, Virginia, and West Virginia.	Presence/probable absence surveys.	Capture, handle, identify, and release.	New.
ES22311A-6 ...	Tennessee Aquarium; Chattanooga, TN.	Alabama cavefish (<i>Speoplatyrhinus poulsoni</i>), amber darter (<i>Percina antesella</i>), Barrens topminnow (<i>Fundulus julisia</i>), blue shiner (<i>Cyprinella caerulea</i>), Cahaba shiner (<i>Notropis cahabae</i>), Conasauga logperch (<i>Percina jenkinsi</i>), Cumberland darter (<i>Etheostoma susanae</i>), frecklebelly madtom (<i>Noturus munitus</i>), goldline darter (<i>Percina aurolineata</i>), laurel dace (<i>Chrosomus saylori</i>), rush darter (<i>Etheostoma phytophylum</i>), sickle darter (<i>Percina williamsi</i>), snail darter (<i>Percina tanasi</i>), trispot darter (<i>Etheostoma trisella</i>), vermilion darter (<i>Etheostoma chermocki</i>), and watercress darter (<i>Etheostoma nuchale</i>).	Alabama, Georgia, Kentucky, Tennessee, and Virginia.	Presence/probable absence surveys, tissue collection for genetic analysis, and captive propagation.	Capture, identify, take fin clips, and release.	Renewal and amendment.

Public Availability of Comments

Written comments we receive become part of the administrative record associated with this action. 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. All submissions from organizations or businesses, and from

individuals identifying themselves as representatives or officials of organizations or businesses, will be made available for public disclosure in their entirety.

Next Steps

If we decide to issue a permit to an applicant listed in this notice, we will publish a notice in the **Federal Register**.

Authority

We publish this notice under section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

John Tirpak,

*Deputy Assistant Regional Director,
Ecological Services, Southeast Region.*

[FR Doc. 2023–10647 Filed 5–17–23; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR**Fish and Wildlife Service**

[Docket No. FWS–R7–NWRs–2023–0072]

**Notice of Intent To Prepare a
Supplemental Environmental Impact
Statement for a Potential Land
Exchange Involving Izembek National
Wildlife Refuge Lands**

AGENCY: Fish and Wildlife Service,
Interior.

ACTION: Notice of intent.

SUMMARY: In accordance with the National Environmental Policy Act of 1969, as amended, and the Alaska National Interest Lands Conservation Act of 1980, as amended, along with other laws as applicable, the U.S. Fish and Wildlife Service (FWS) intends to prepare a supplemental environmental impact statement (supplemental EIS) to consider the effects of a potential land exchange of certain lands owned by the King Cove Corporation and/or the State of Alaska with certain lands owned by the U.S. Government. King Cove would use the acquired land for a road corridor for noncommercial use through the Izembek National Wildlife Refuge and the Izembek Wilderness Area. We furnish this notice to advise the public and other agencies of our intentions and to seek information and suggestions on the scope of issues to be addressed in the supplemental EIS. In particular, we will update information used in the 2013 analysis on the impacts of a then-proposed exchange and road corridor and the viability of alternatives to provide safe and reliable transportation between the City of King Cove, Alaska, and the airport at Cold Bay, Alaska.

DATES: This notice initiates the public scoping process for the supplemental EIS. The FWS must receive any public comments concerning the scope of the analysis, potential alternatives, and

identification of relevant information and studies no later than June 20, 2023.

ADDRESSES:

Obtaining documents: To inform public comment, we are making FWS's 2013 EIS and ROD documents available for review at <https://www.regulations.gov> in Docket No. FWS–R7–NWRs–2023–0072. In addition, any comments and other materials that we receive will be available for public inspection online at that site.

Submitting public comments: You may submit comments related to the potential Izembek land exchange and other potential transportation solutions by any of the following methods:

- **Online:** <https://www.regulations.gov>.

Follow the instructions for submitting comments on Docket No. FWS–R7–NWRs–2023–0072.

- **U.S. mail:** Public Comments Processing, Attn: Docket No. FWS–R7–NWRs–2023–0072; U.S. Fish and Wildlife Service, MS: PRB/3W; 5275 Leesburg Pike; Falls Church, VA 22041–3803.

We will post all comments on <https://www.regulations.gov>. This generally means that we will post any personal information you provide us (see Public Review Process, below, for more information).

FOR FURTHER INFORMATION CONTACT:

Shane Walker, Branch Chief of Conservation Planning and Policy, by telephone at 907–226–4626; by email at shane_walker@fws.gov; or via U.S. mail at U.S. Fish & Wildlife Service, Alaska Region, National Wildlife Refuge System, 95 Sterling Highway, Suite 1, Homer, AK 99603. Contact Shane Walker to have your name added to our mailing list. 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: The Izembek National Wildlife Refuge (417,533 acres (ac)) and the North Creek (8,452 ac) and Pavlof (1,447,264 ac) units of the Alaska Peninsula National Wildlife Refuge are located at the westernmost tip of the Alaska Peninsula. The 1,008,697-ac Unimak Island (the easternmost Aleutian Island of the Alaska Maritime National Wildlife Refuge) lies across the Isanotski Strait. To the north of the Izembek Refuge is the Bering Sea; to the south is

the Pacific Ocean. The Izembek Wilderness covers much of the Izembek National Wildlife Refuge and includes pristine streams, extensive wetlands, steep mountains, tundra, and sand dunes, and provides high scenic, wildlife, and scientific values, as well as opportunities for solitude and recreation. The Izembek National Wildlife Refuge includes the traditional homelands of the Unanga people.

The King Cove Corporation is an Alaska Native Village Corporation established under the Alaska Native Claims Settlement Act of 1971 (ANCSA; 43 U.S.C. 1601 *et seq.*). Under the authority of ANCSA, Congress granted to King Cove Corporation land entitlements within and adjacent to Izembek Refuge. The State of Alaska also owns lands, submerged lands, shorelands, and tidelands within and adjacent to Izembek and Alaska Peninsula Refuges, including the Izembek State Game Refuge.

The Alaska Maritime National Wildlife Refuge stretches from the Arctic Ocean to the southeast panhandle of Alaska and protects breeding habitat for seabirds, marine mammals, and other wildlife on more than 2,500 islands, spires, rocks, and coastal headlands. Sitkinak Island, which lies within the boundaries of the Alaska Maritime National Wildlife Refuge, is primarily owned by the State of Alaska, with two parcels owned by the Service.

In the Omnibus Public Land Management Act of 2009 (Pub. L. 111–11, title VI, subtitle E (“the 2009 Act”), Congress directed FWS to prepare an EIS under the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 *et seq.*), and its implementing regulations (40 CFR parts 1500–1508) to evaluate the impacts of a proposed land exchange with the State of Alaska and the King Cove Corporation for the purpose of constructing a single-lane gravel road between the communities of King Cove and Cold Bay, Alaska. The 2009 Act required that the road “shall be used primarily for health and safety purposes (including access to and from the Cold Bay Airport) and only for noncommercial purposes,” with limited exceptions. The land exchange contemplated by the 2009 Act would have involved the removal of approximately 206 ac within the Izembek Wilderness portion of Izembek National Wildlife Refuge for the road corridor and approximately 1,600 ac of Federal land within the Alaska Maritime National Wildlife Refuge on Sitkinak Island. In exchange, the FWS would have received approximately

43,093 ac of land owned by the State of Alaska and approximately 13,300 ac of land owned by the King Cove Corporation.

These lands are located around Cold Bay and are adjacent to the North Creek Unit of the Alaska Peninsula National Wildlife Refuge.

In accordance with section 6402(b)(2)(B) of the 2009 Act, an EIS completed in 2013 (2013 EIS; February 6, 2013, 78 FR 8577) analyzed the proposed land exchange and the potential construction and operation of a road between the communities of King Cove and Cold Bay, Alaska, and, among other alternatives, evaluated a specific road corridor through the Izembek Refuge that was identified in consultation with the State of Alaska, the City of King Cove, and the Agdaagux Tribe of King Cove. In accordance with the 2009 Act, subsequent to the preparation of the EIS and in conjunction with the 2013 record of decision (2013 ROD; February 20, 2014, 79 FR 9759), Secretary of the Interior Sally Jewell decided not to enter a land exchange after determining the land exchange (including the construction of the proposed road) was not in the public interest.

On July 3, 2019, Secretary of the Interior David Bernhardt signed a memorandum titled “Findings and Conclusions Concerning a Proposed Land Exchange Between the Secretary of the Interior and King Cove Corporation for Lands Within Izembek National Wildlife Refuge, Alaska” (2019 Secretarial Memorandum). That memorandum laid the foundation for the concurrent approval of a land exchange agreement (2019 Exchange Agreement) between the Department of the Interior and King Cove Corporation. The 2019 Secretarial Memorandum stated that the purpose of the 2019 Exchange Agreement was to allow a road across the Izembek National Wildlife Refuge to improve access by the residents of King Cove to the airport at Cold Bay. Since the authorities under the 2009 Act had expired, the 2019 Exchange Agreement relied on the general exchange authority found at in section 1302(h) of the Alaska National Interest Lands Conservation Act of 1980 (Pub. L. 96–487, sec. 1302(h), Dec. 2, 1980; 16 U.S.C. 3192(h)). However, the 2019 Exchange Agreement relied in large part on the record developed for the exchange analyzed under the 2013 EIS and rejected by Secretary Jewell in the 2013 ROD.

On June 1, 2020, the District Court for the District of Alaska vacated the 2019 Exchange Agreement. The vacatur order, which remains in effect, was based on

several legal defects in the decision, including the district court’s conclusion that Secretary Bernhardt failed to properly justify the change in policy and his rejection of Secretary Jewell’s prior conclusions. The district court did not rule on claims that Secretary Bernhardt’s 2019 decision violated the National Environmental Policy Act (NEPA) or the Endangered Species Act (ESA; 16 U.S.C. 1531 *et seq.*) Therefore, those claims are pending and have not yet been addressed. Review of the district court’s judgment is pending before an *en banc* panel of the Ninth Circuit Court of Appeals.

On March 14, 2023, Secretary of the Interior Deb Haaland issued a new decision memorandum withdrawing the Department from the 2019 Exchange Agreement between the Secretary of the Interior and King Cove Corporation. That decision memorandum identified concerns with analysis of the 2019 Exchange Agreement’s potential impacts on subsistence uses and needs, and highlighted shortcomings in the record regarding NEPA and ESA analyses. In addition, the Secretary expressed significant policy concerns regarding the nonpublic manner in which the 2019 Exchange Agreement was accomplished, as well as the terms of the exchange agreement, which differed from the exchange evaluated in the 2013 EIS.

While the authorities in the 2009 Act remain expired, the FWS will prepare a supplemental EIS to address an exchange under section 1302(h) of ANILCA or under other authorities, as applicable. The FWS’s supplemental EIS analysis will focus on thoroughly assessing the impacts of the potential exchange and road, allowing for public participation, and integrating the NEPA analysis with an evaluation under ANILCA section 810. The FWS will also use and coordinate the NEPA process to help inform the Department with respect to compliance with the National Historic Preservation Act section 106 (54 U.S.C. 306108), the ESA, ANILCA (including any land exchange’s furtherance of the statute’s conservation and subsistence purposes), ANCSA (43 U.S.C. 1601 *et seq.*), the National Wildlife Refuge System Improvement Act of 1997 (16 U.S.C. 668dd), and the Wilderness Act of 1964 (16 U.S.C. 1131 *et seq.*).

Potential action alternatives under consideration at this time include one or more of the action alternatives from the 2013 EIS addressing the proposed land exchange and road construction and operation as outlined in the 2009 Act, one or more of the action alternatives from the 2013 EIS addressing other

transportation alternatives, and a new alternative for the terms of the proposed land exchange for a road corridor approved in 2019.

Public Review Process

Request for Public Comments

The FWS is seeking public comments on issues, concerns, potential impacts, alternatives, and mitigation measures that should be considered in the analysis, particularly those not already addressed in the 2013 EIS or in need of updating. Additional opportunities for public participation, including a public comment period of at least 45 days, will be provided upon publication of the draft supplemental EIS.

It is important that commenters provide their comments at such times and in such manner that they are useful to the agency’s preparation of the supplemental EIS. Therefore, comments should be received prior to the close of the comment period and should clearly articulate the commenters’ concerns.

Public Availability of Comments

You may submit written comments and materials concerning this proposed rule by one of the methods listed in **ADDRESSES**. Comments submitted anonymously will be accepted and considered.

If you submit a comment via <https://www.regulations.gov>, your entire comment, including any personal identifying information such as your address, phone number, and email address, will be posted on the website.

If you submit a hardcopy comment that includes personal identifying information, you may request at the top of your document that we withhold this information from public review. However, we cannot guarantee that we will be able to do so. We will post all hardcopy comments on <https://www.regulations.gov>.

Tribal Consultation and Comment

The meaningful input of Alaska Native Tribes and Alaska Native Corporations is of critical importance to this supplemental EIS. Therefore, and as expressed in Executive Order 13175, “Consultation and Coordination with Indian Tribal Governments,” the Federal officials that have been delegated authority by the Secretary are committed to honoring the unique government-to-government political relationship that exists between the Federal Government and federally recognized Tribes (Tribes). Consultation with Alaska Native Corporations is based on Public Law 108–199, div. H, sec. 161, January 23, 2004, 118 Stat. 452,

as amended by Public Law 108–447, div. H, title V, sec. 518, December 8, 2004, 118 Stat. 3267, which provides that: “The Director of the Office of Management and Budget and all Federal agencies shall hereafter consult with Alaska Native corporations on the same basis as Indian Tribes under Executive Order No. 13175.” The FWS will hold individual consultation meetings upon request. The Secretary will consider Alaska Native Tribes’ and Alaska Native Corporations’ information, input, and recommendations, and address their concerns as much as practicable.

Reasonable Accommodations

The Department is committed to providing access to this process for all participants. For more information, see **FOR FURTHER INFORMATION CONTACT**.

Signing Authority

Shannon A. Estenoz, Assistant Secretary for Fish and Wildlife and Parks, approved this action on May 15, 2023, for publication. On May 15, 2023, Shannon A. Estenoz authorized the undersigned to sign the document electronically and submit it to the Office of the Federal Register for publication as an official document of the U.S. Fish and Wildlife Service.

Maureen D. Foster,

Chief of Staff, Office of the Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 2023–10621 Filed 5–17–23; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[FWS–R1–ES–2023–N036;
FXES11130100000–234–FF01E00000]

Endangered Species; Receipt of Recovery Permit Applications

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of permit applications; request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service, have received applications for permits to conduct activities intended to enhance the propagation and survival of endangered species under the Endangered Species Act. We invite the public and local, State, Tribal, and Federal agencies to comment on these applications. Before issuing the requested permits, we will take into consideration any information that we receive during the public comment period.

DATES: We must receive your written comments on or before June 20, 2023.

ADDRESSES:

Document availability and comment submission: Submit a request for a copy of the application and related documents and submit any comments by one of the following methods. All requests and comments should specify the applicant name and application number (e.g., Dana Ross, ES001705):

- *Email:* permitsR1ES@fws.gov.
- *U.S. Mail:* Marilet Zablan, Regional Program Manager, Restoration and Endangered Species Classification, Ecological Services, U.S. Fish and Wildlife Service, Pacific Regional Office, 911 NE 11th Avenue, Portland, OR 97232–4181.

FOR FURTHER INFORMATION CONTACT:

Karen Colson, Regional Recovery Permit Coordinator, Ecological Services, (503) 231–6283 (telephone); permitsR1ES@fws.gov (email). 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: We, the U.S. Fish and Wildlife Service, invite the public to comment on applications for permits under section 10(a)(1)(A) of the Endangered Species Act of 1973, as amended (ESA; 16 U.S.C. 1531 *et seq.*).

The requested permits would allow the applicants to conduct activities intended to promote recovery of species that are listed as endangered under the ESA.

Background

With some exceptions, the ESA prohibits activities that constitute take of listed species unless a Federal permit is issued that allows such activity. The ESA’s definition of “take” includes such activities as pursuing, harassing, trapping, capturing, or collecting, in addition to hunting, shooting, harming, wounding, or killing.

A recovery permit issued by us under section 10(a)(1)(A) of the ESA authorizes the permittee to conduct activities with endangered or threatened species for scientific purposes that promote recovery or for enhancement of propagation or survival of the species. These activities often include such prohibited actions as capture and collection. Our regulations implementing section 10(a)(1)(A) for these permits are found in the Code of Federal Regulations (CFR) at 50 CFR 17.22 for endangered wildlife species, 50 CFR 17.32 for threatened wildlife species, 50 CFR 17.62 for endangered plant species, and 50 CFR 17.72 for threatened plant species.

Permit Applications Available for Review and Comment

Proposed activities in the following permit requests are for the recovery and enhancement of propagation or survival of the species in the wild. The ESA requires that we invite public comment before issuing these permits. Accordingly, we invite local, State, Tribal, and Federal agencies and the public to submit written data, views, or arguments with respect to these applications. The comments and recommendations that will be most useful and likely to influence agency decisions are those supported by quantitative information or studies.

Application No.	Applicant, city, state	Species	Location	Take activity	Permit action
ES056557	U.S. Bureau of Reclamation, ID.	Snake River physa (<i>Physa natricina</i>)	Idaho	Harass by survey, capture, mark, transport, release, and collect voucher specimens..	Renew.

Application No.	Applicant, city, state	Species	Location	Take activity	Permit action
PER1353215	Clare Aslan, Northern Arizona University, AZ.	No common name (NCN) (<i>Stenogyne angustifolia</i>), honohono (<i>Haplostachys haplostachya</i>), NCN (<i>Silene lanceolata</i>), po'e (<i>Portulaca sclerocarpa</i>), a'e (<i>Zanthoxylum hawaiiense</i>), NCN (<i>Festuca hawaiiensis</i>), heau (<i>Exocarpos menziesii</i>).	Hawaii	Remove/reduce to possession—handle and monitor..	New.
ES043638	U.S. Army Garrison, Directorate of Public Works, HI.	NCN (<i>Abutilon sandwicense</i>) and 14 other vascular plant species.	Hawaii	Remove/reduce to possession—handle, swab, collect flow-ers..	Renew and amend.

Public Availability of Comments

Written comments we receive become part of the administrative record associated with this action. 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 request in your comment that we withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so. All submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, will be made available for public disclosure in their entirety.

Next Steps

If we decide to issue a permit to the applicant listed in this notice, we will publish a notice in the **Federal Register**.

Authority

We publish this notice under section 10(c) of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

Marilet A. Zablan,

Regional Program Manager for Restoration and Endangered Species Classification, Pacific Region.

[FR Doc. 2023–10612 Filed 5–17–23; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0035860; PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: Columbia Gorge Discovery Center and Museum, The Dalles, OR

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Columbia Gorge Discovery Center and Museum has completed an inventory of human remains and has determined that there is a cultural affiliation between the human remains and Indian Tribes or Native Hawaiian organizations in this notice. The human remains were removed from an unknown burial site on the banks of the Columbia River (between Washington and Oregon) of the Columbia River Plateau and Klickitat County, WA.

DATES: Repatriation of the human remains in this notice may occur on or after June 20, 2023.

ADDRESSES: Susan Buce, Columbia Gorge Discovery Center & Museum, 5000 Discovery Drive, The Dalles, OR 97058, telephone (541) 296–8600 Ext. 242, email collections@gorgediscovery.org.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Columbia Gorge Discovery Center and Museum. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records held by the Columbia Gorge Discovery Center and Museum.

Description

Human remains representing, at minimum, one individual were removed at an unknown time from a burial site located along the banks or islands of the Columbia River near The Dalles, in Wasco County, OR, and Wishram, in Klickitat County, WA, by James Gosson. In 2003, Gosson donated these human

remains to the Museum. The human remains belong to an adult of unknown sex. No known individual was identified. No associated funerary objects are present.

Human remains representing, at minimum, one individual were removed from private property in White Salmon, Klickitat County, WA by Allen B. Clarke. Clarke found these human remains while digging out his basement. Following his death, the human remains were donated to the Museum in 2013 by his wife, Rosalie Clarke. The human remains belong to an adult male. No known individual was identified. No associated funerary objects are present.

Native American People from both sides of the Columbia River utilized the islands on the Columbia River that border the present-day states of Oregon and Washington, in the north central Columbia River Plateau region, for burial. Early and late published ethnographic documentation indicates that this area was the aboriginal territory of the Western Columbia River Sahaptins, Wasco, Wishram, Yakima, Walla Walla, Umatilla, Tenino, and Skin (Daugherty 1973, Hale 1841, Hunn and French 1998, Stern 1998, French and French 1998, Mooney 1896, Murdock 1938, Ray 1936 and 1974, Spier 1936).

Cultural Affiliation

The human remains and associated funerary objects in this notice are connected to one or more identifiable earlier groups, tribes, peoples, or cultures. There is a relationship of shared group identity between the identifiable earlier groups, tribes, peoples, or cultures and one or more Indian Tribes or Native Hawaiian organizations. The following types of information were used to reasonably trace the relationship: geographical and historical.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after

consultation with the appropriate Indian Tribes and Native Hawaiian organizations, the Columbia Gorge Discovery Center and Museum has determined that:

- The human remains described in this notice represent the physical remains of two individuals of Native American ancestry.
- There is a relationship of shared group identity that can be reasonably traced between the human remains and associated funerary objects described in this notice and the Confederated Tribes and Bands of the Yakama Nation; Confederated Tribes of the Umatilla Indian Reservation; and the Confederated Tribes of the Warm Springs Reservation of Oregon.

Requests for Repatriation

Written requests for repatriation of the human remains in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for repatriation may be submitted by:

1. Any one or more of the Indian Tribes or Native Hawaiian organizations identified in this notice.
2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the human remains in this notice to a requestor may occur on or after June 20, 2023. If competing requests for repatriation are received, the Columbia Gorge Discovery Center and Museum must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the human remains and associated funerary objects are considered a single request and not competing requests. The Columbia Gorge Discovery Center and Museum is responsible for sending a copy of this notice to the Indian Tribes identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.9, 10.10, and 10.14.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023-10555 Filed 5-17-23; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-D-COS-POL-35730;
PPWODIREP0; PPMPAS1Y.000000;
PX.XDIRE0039]

Notice of Public Meeting for the Advisory Committee on Reconciliation in Place Names

AGENCY: National Park Service, Interior.

ACTION: Meeting notice.

SUMMARY: In accordance with the Federal Advisory Committee Act of 1972, the National Park Service (NPS) is hereby giving notice that the Advisory Committee on Reconciliation in Place Names (Committee) will meet as noted below.

DATES: The Committee will hold public meetings on Wednesday June 14, 2023, from 8:00 a.m. until 5:00 p.m. (MOUNTAIN) and Thursday June 15, 2023, from 8:00 a.m. until 12:00 p.m. (MOUNTAIN). Individuals that wish to participate must contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section no later than June 7, 2023, to receive instructions for accessing the meeting.

ADDRESSES: The Committee will meet at the Horace M. Albright Training Center, 1 Albright Avenue, Grand Canyon, Arizona 86023. Electronic submissions of materials or requests are to be sent to reconciliation_committee@nps.gov. The meeting will also be accessible virtually via webinar and audio conference technology.

FOR FURTHER INFORMATION CONTACT: For information concerning attending the Committee meeting in-person or virtually, submitting written comments to the Committee, or requesting to address the Committee, contact Andrea DeKoter, Committee Manager for the Advisory Committee on Reconciliation in Place Names, Office of Policy, National Park Service, at reconciliation_committee@nps.gov or by telephone at (202) 354-2220.

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: The Committee has been established by authority of the Secretary of the Interior (Secretary) under 54 U.S.C. 100906 and

is regulated by the Federal Advisory Committee Act.

Purpose of the Meeting: The Committee will receive briefings and discuss topics related to identifying existing Federal land unit names and geographic feature names that may be considered derogatory and developing recommendations for potential replacement names. The final agenda and briefing materials will be posted to the Committee's website prior to the meeting at <https://www.nps.gov/orgs/1892/advisory-committee-on-reconciliation-in-place-names.htm>.

The meeting is open to the public. Interested persons may choose to make oral comments at the meeting during the designated time for this purpose. Depending on the number of people wishing to comment and the time available, the amount of time for oral comments may be limited. Interested parties should contact the Committee Manager (see **FOR FURTHER INFORMATION CONTACT**) for advance placement on the public speaker list for this meeting. Members of the public may also choose to submit written comments by emailing them to reconciliation_committee@nps.gov. Due to time constraints during the meeting, the Committee is not able to read written public comments submitted into the record. All comments will be made part of the public record and will be electronically distributed to all Committee members. Detailed minutes of the meeting will be available for public inspection within 90 days of the meeting.

Meeting Accessibility

Please make requests in advance for sign language interpreter services, assistive listening devices, or other reasonable accommodations. We ask that you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice at least seven (7) business days prior to the meeting to give the Department of the Interior sufficient time to process your request. All reasonable accommodation requests are managed on a case-by-case basis.

Public Disclosure of Comments: 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.

Authority: 5 U.S.C. ch. 10.

Alma Rippes,

Chief, Office of Policy.

[FR Doc. 2023-10636 Filed 5-17-23; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0035865;
PPWOCRADN0-PCU00RP14.R50000]

Notice of Intent To Repatriate Cultural Items: Yuba County Water Agency, Marysville, CA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), Yuba County Water Agency (YCWA) intends to repatriate certain cultural items that meet the definition of objects of cultural patrimony and that have a cultural affiliation with the Indian Tribes or Native Hawaiian organizations in this notice. The cultural items were removed from Yuba County, CA.

DATES: Repatriation of the cultural items in this notice may occur on or after June 20, 2023.

ADDRESSES: Jacob Vander Meulen, YCWA, 1220 F Street, Marysville, CA 95901, telephone (530) 443-7412, email jvandermeulen@yubawater.org.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of YCWA. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the summary or related records held by YCWA.

Description

Four lots of objects of cultural patrimony were removed from Yuba County, CA. They are described below.

In 1966, one lot of cultural items was removed from an area near the southwestern end of Garden Valley during excavations carried out under the direction of archeologist Stephen E. Humphreys prior to inundation of the area by the Yuba County Water Agency's New Bullards Bar Project. The location was given archeological site numbers CA-YUB-018, P-58-0036, YUB-S21, and BB#4. They are currently located at the California State University

Sacramento (CSU Sacramento) curation facility. This lot contains projectile points and projectile point fragments, knives, scrapers, cores, choppers, ground or pecked stones including pestles, hammerstone, mano fragments, abrading stones, steatite objects, ochre, and other uncategorized objects.

In 1966, one lot of cultural items was removed from an area near Garden Valley during excavations carried out under the direction of archeologist Stephen E. Humphreys prior to inundation of the area by the Yuba County Water Agency's New Bullards Bar Project. The location was given archeological site numbers CA-YUB-019, P-58-0037, YUB-S22, and BB#5. They are currently located at the CSU Sacramento curation facility. This lot contains projectile points and projectile point fragments, drills, knives and knife fragments, scrapers and halfted scrapers/knives, gravers, cores, choppers, ground or pecked stones including pestles, mano fragments, metates, and other uncategorized objects.

In 1966, one lot of cultural items was removed from an area overlooking a tributary of Willow Creek during excavations carried out under the direction of archeologist Stephen E. Humphreys prior to inundation of the area by the Yuba County Water Agency's New Bullards Bar Project. The location was given archeological site numbers CA-YUB-021, P-58-0039, YUB-S24, AR6(?), and BB#7. They are currently located at the CSU Sacramento curation facility. This lot contains groundstone flakes and other uncategorized objects.

In 1966, one lot of cultural items was removed from the southeast side of Garden Valley during excavations carried out under the direction of archeologist Stephen E. Humphreys prior to inundation of the area by the Yuba County Water Agency's New Bullards Bar Project. The location was given archeologically designated site numbers: CA-YUB-0024, YUB-S19, SSC1, BB#2, and P-58-0042. They are currently located at the CSU Sacramento curation facility. This lot contains projectile points and projectile point fragments, obsidian gravers, drills, spear points, halfted knives, scrapers, cores, choppers, ground/battered stone tools, rubbing stones, mortar fragments, a net sinker, an anvil stone, pestles, hammerstones, a shaped stone, a pendant, modified and unmodified steatite fragments (including bowl, cup, and dish fragments), red ochre, modified bones, a glass bead, a shaft polisher, shell fragments, and quartz crystals.

Cultural Affiliation

The cultural items in this notice are connected to one or more identifiable earlier groups, tribes, peoples, or cultures. There is a relationship of shared group identity between the identifiable earlier groups, tribes, peoples, or cultures and one or more Indian Tribes or Native Hawaiian organizations. The following types of information were used to reasonably trace the relationship: based on geographical, kinship, biological, archeological, anthropological, linguistic, folkloric, oral traditional, historical, and expert opinion, including tribal traditional knowledge.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after consultation with the appropriate Indian Tribes and Native Hawaiian organizations, YCWA has determined that:

- The four lots of cultural items described above have ongoing historical, traditional, or cultural importance central to the Native American group or culture itself, rather than property owned by an individual.
- There is a relationship of shared group identity that can be reasonably traced between the cultural items and the United Auburn Indian Community of the Auburn Rancheria of California.

Requests for Repatriation

Additional, written requests for repatriation of the cultural items in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for repatriation may be submitted by any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the cultural items in this notice to a requestor may occur on or after June 20, 2023. If competing requests for repatriation are received, YCWA must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the cultural items are considered a single request and not competing requests. YCWA is responsible for sending a copy of this notice to the Indian Tribe identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.8, 10.10, and 10.14.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023–10560 Filed 5–17–23; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0035864;
PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: Museum of the Rockies, Bozeman, MT

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), Museum of the Rockies (MOR) has completed an inventory of human remains and associated funerary objects and has determined that there is a cultural affiliation between the human remains and associated funerary objects and Indian Tribes or Native Hawaiian organizations in this notice. The human remains and associated funerary objects were removed from Yellowstone, Big Horn, and Carbon Counties, MT.

DATES: Repatriation of the human remains and associated funerary objects in this notice may occur on or after June 20, 2023.

ADDRESSES: Melissa Dawn, Cultural History Registrar and Collections Manager, Museum of the Rockies, P.O. Box 172720, 600 W. Kagy Blvd., Bozeman, MT 59717, telephone (406) 994–2242, email melissa.dawn@montana.edu and Eric Metz, Paleontology Collections Manager—Registrar, Museum of the Rockies, P.O. Box 172720, 600 W. Kagy Blvd., Bozeman, MT 59717, telephone (406) 994–6578, email eric.metz@montana.edu.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of Museum of the Rockies. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records held by Museum of the Rockies.

Description

In 1951, human remains representing, at minimum, one individual were removed from Yellowstone County, MT,

by Joseph L. Cramer. In 1991, these human remains were donated to the Museum of the Rockies (MOR) by Joseph L. Cramer. The decedent, possibly a smallpox victim, had been placed in wide crack in the earth and burned. The human remains—skull fragments—possibly belong to a female). The 26 associated funerary objects are 24 glass trade beads, one copper trade button, and one copper wire (possibly an earring).

On April 3, 1938, 94 funerary objects were removed from a grave in small cave shelter five or six miles west of the Big Horn River and approximately six miles northwest of Hardin, in Big Horn County, MT, by Oscar T. Lewis. The grave had already been excavated and was presumed to belong to a Crow individual. In 1991, these funerary objects were donated to MOR by Joseph L. Cramer. No human remains are present. The 94 funerary objects are 24 glass trade beads, 10 copper trade beads, nine copper rolls (seven rolls and two parts), and 51 cowrie shell beads (38 complete shells and 13 small beads).

At an unknown date, 86 funerary objects were removed from Lodge Grass in Big Horn County, MT. These funerary objects were purchased by Joseph L. Cramer in 1955, and in 1991, Cramer donated them to MOR. Cramer surmised that these objects were found in a historic Crow burial by a Crow Indian, were removed and restrung, and then were sold to a filling station owner at Lodge Grass. No human remains are present. The 86 funerary objects are trade beads from a necklace.

Around 1953, 25 funerary objects were removed from Big Horn County, MT. These funerary objects were found by Art Becker of Billings, MT, eroding from a historic Crow Indian burial located at the head of Cottonwood Creek, a tributary of Hay Creek. In 1957, the funerary objects were gifted to Joseph L. Cramer, and in 1991, Cramer donated them to MOR. No human remains are present. The 25 funerary objects are brass, glass, shell, and bone beads.

Sometime during the 1940s–1950s, 87 funerary objects were removed from the Crow Indian Reservation in Big Horn County, MT. These funerary objects were found by Roy Marsh of Pryor, MT, eroding from Crow Indian burials and surface collected by him. On November 6, 1958, the funerary objects were gifted to Joseph L. Cramer, and in 1991, Cramer donated them to MOR. No human remains are present. The 87 funerary objects are glass and brass trade beads.

In 1951, human remains representing, at minimum, one individual were

removed from a mesa in Carbon County, MT, by Joseph L. Cramer. The mesa, located 1.5 miles southeast of Joliet Town, is the divide between Rock Creek & Elbow Creek. In 1991, Cramer donated these human remains to MOR. The human remains—three skull fragments, one femur fragment, one metatarsal, six phalanges, and six teeth—belong to an individual of unknown age and sex. The 24 associated funerary objects are 22 glass and shell beads strung between two buttons.

In 1953, human remains representing, at minimum, one individual were removed from the south rim of a mesa in Carbon County, MT, by Joseph L. Cramer. This area, situated between Rock Creek & Elbow Creek, 1.5 miles southeast of Joliet Town, contains Crow crevice burials. In 1991, Cramer donated these human remains to MOR. The human remains—one metatarsal and one possibly burned bone—belong to an individual of unknown age and sex. The 69 associated funerary objects are glass and bone beads.

At an unknown date, nine funerary objects were removed from the base of the north rim of a small tributary 1¼ miles west of Pryor Creek channel, in Yellowstone County, MT, by Oscar T. Lewis. In 1991, these funerary objects were donated to MOR by Joseph L. Cramer. No human remains are present. The nine associated funerary objects are eight perforated elk teeth and one lot comprised of several hundred seed beads.

Cultural Affiliation

The human remains and associated funerary objects in this notice are connected to one or more identifiable earlier groups, tribes, peoples, or cultures. There is a relationship of shared group identity between the identifiable earlier groups, tribes, peoples, or cultures and one or more Indian Tribes or Native Hawaiian organizations. The following types of information were used to reasonably trace the relationship: archeological, geographical, and historical.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after consultation with the appropriate Indian Tribes and Native Hawaiian organizations, Museum of the Rockies has determined that:

- The human remains described in this notice represent the physical remains of three individuals of Native American ancestry.
- The 420 objects described in this notice are reasonably believed to have been placed with or near individual

human remains at the time of death or later as part of the death rite or ceremony.

- There is a relationship of shared group identity that can be reasonably traced between the human remains and associated funerary objects described in this notice and the Crow Tribe of Montana.

Requests for Repatriation

Written requests for repatriation of the human remains and associated funerary objects in this notice must be sent to the Responsible Official identified in

ADDRESSES. Requests for repatriation may be submitted by:

1. Any one or more of the Indian Tribes or Native Hawaiian organizations identified in this notice.

2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the human remains and associated funerary objects in this notice to a requestor may occur on or after June 20, 2023. If competing requests for repatriation are received, Museum of the Rockies must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the human remains and associated funerary objects are considered a single request and not competing requests. Museum of the Rockies is responsible for sending a copy of this notice to the Indian Tribe identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.9, 10.10, and 10.14.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023-10559 Filed 5-17-23; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0035863;
PPWOCRADNO-PCU00RP14.R50000]

Notice of Inventory Completion: Gilcrease Museum, Tulsa, OK

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the

Gilcrease Museum has completed an inventory of human remains and associated funerary objects and has determined that there is no cultural affiliation between the human remains and associated funerary objects and any Indian Tribe. The human remains and associated funerary objects were removed from Limestone and Morgan Counties, AL.

DATES: Disposition of the human remains and associated funerary objects in this notice may occur on or after June 20, 2023.

ADDRESSES: Laura Bryant, Gilcrease Museum, 800 S Tucker Drive, Tulsa, OK 74104, telephone (918) 596-2747, email laura-bryant@tulsa.edu.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Gilcrease Museum. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records held by the Gilcrease Museum.

Description

All the human remains and associated funerary objects listed below were removed in the 1950s by Frank J. Soday, a collector and amateur archeologist. The Thomas Gilcrease Museum Association purchased the Soday Collection in 1982, and subsequently donated the collection to the Gilcrease Museum.

Human remains representing, at minimum, one individual were removed from Chemstrand, Harbor Island, in Morgan County, AL (Soday site number 504). No known individual was identified. The one associated funerary object is a lot consisting of faunal remains, including turtle and bird.

The associated funerary objects listed below were recently found at the Gilcrease Museum. The human remains with which these funerary objects are associated (together with additional associated funerary objects) were listed in a notice published in the **Federal Register** on September 20, 2016 (81 FR 64503-64505) and have since been repatriated.

One associated funerary object was removed from Limestone County, AL. Most likely, this object was removed from one of the following sites: 1LI27, 1LI49, 1LI52, or 1LI53 (Soday site number 399). The one associated funerary object is a lot consisting of lithic tools and projectile points.

Two associated funerary objects were removed from Skeleton Island (Soday site number 401) in Limestone County, AL. The two associated funerary objects are two lots consisting of lithic tools and projectile points.

One associated funerary object was removed from Center Island East (Soday site number 423) in Limestone County, AL. The one associated funerary object is a lot consisting of projectile points.

One associated funerary object was removed from East Middle Quad/TVA (Soday site number 428) in Limestone County, AL. The one associated funerary object is a lot consisting of lithic tools and projectile points.

One associated funerary object was removed from West Middle Quad, Decatur (Soday site number 435) in Morgan County, AL. The one associated funerary object is a lot consisting of lithic tools.

One associated funerary object was removed from Bald Knob Cemetery/Folsom Graveyard (Soday site number 456) in Morgan County, AL. The one associated funerary object is a lot consisting of lithic tools.

One associated funerary object was removed from Strap Handle Island (Soday site number 489) in Limestone County, AL. The one associated funerary object is a lot consisting of lithic tools.

Aboriginal Land

The human remains and associated funerary objects in this notice were removed from known geographic locations. These locations are the aboriginal lands of one or more Indian Tribes. The following information was used to identify the aboriginal land: a final judgment of the Indian Claims Commission or the United States Court of Claims, and a treaty.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after consultation with the appropriate Indian Tribes, the Gilcrease Museum has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.

- The nine objects described in this notice are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony.

- No relationship of shared group identity can be reasonably traced between the human remains and associated funerary objects and any Indian Tribe.

- The human remains and associated funerary objects described in this notice were removed from the aboriginal land of the Cherokee Nation; Eastern Band of Cherokee Indians; The Chickasaw Nation; The Muscogee (Creek) Nation; and the United Keetoowah Band of Cherokee Indians in Oklahoma.

Requests for Disposition

Written requests for disposition of the human remains and associated funerary objects in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for disposition may be submitted by:

1. Any one or more of the Indian Tribes identified in this notice.
2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization, or who shows that the requestor is an aboriginal land Indian Tribe.

Disposition of the human remains and associated funerary objects described in this notice to a requestor may occur on or after June 20, 2023. If competing requests for disposition are received, the Gilcrease Museum must determine the most appropriate requestor prior to disposition. Requests for joint disposition of the human remains and associated funerary objects are considered a single request and not competing requests. The Gilcrease Museum is responsible for sending a copy of this notice to the Indian Tribes identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.9 and 10.11.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023-10558 Filed 5-17-23; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0035859;
PPWOCRADNO-PCU00RP14.R50000]

Notice of Inventory Completion: Wasco County/Dalles City Museum Commission, The Dalles, OR

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Wasco

County/Dalles City Museum Commission has completed an inventory of human remains and associated funerary objects and has determined that there is a cultural affiliation between the human remains and associated funerary objects and Indian Tribes or Native Hawaiian organizations in this notice. The human remains and associated funerary objects were removed from unknown burial sites on the banks of the Columbia River (between Washington and Oregon) of the Columbia River Plateau.

DATES: Repatriation of the human remains and associated funerary objects in this notice may occur on or after June 20, 2023.

ADDRESSES: Susan Buce, Columbia Gorge Discovery Center & Museum, 5000 Discovery Drive, The Dalles, OR 97058, telephone (541) 296-3202, email collections@gorgediscovery.org or Eric Gleason, Vice-President, Wasco County/Dalles City Museum Commission, c/o Fort Dalles Museum, 500 W 15th Street, The Dalles, OR 97058, telephone (541) 296-4547, email fortdallesmuseum@gmail.com.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Wasco County/Dalles City Museum Commission. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records held by the Wasco County/Dalles City Museum Commission.

Description

Human remains representing, at minimum, one individual were removed from an unknown burial site along the banks or islands of the Columbia River near The Dalles, OR, and Wishram, WA. In 1971, human remains represented by a skull with lower jaw and 14 teeth—belonging to an adult female were donated to the Museum by Walter Kinnersley. No known individual was identified. No associated funerary objects are present.

Human remains representing, at minimum, two individuals were removed from the banks of the Columbia River near The Dalles, OR, most likely "Memaloose Island." At an unknown date, a box containing the human remains and associated funerary objects was donated to the Museum by an unknown individual. The human remains represent a female of unknown

age and an individual of unknown age and sex. No known individuals were identified. The seven associated funerary objects are one lot consisting of cloth (with yellow, pink and green flowers), one lot consisting of leaves, one lot consisting of soil, one lot consisting of historic nails, one lot consisting of shells, one lot consisting of rocks, and one lot consisting of basketry.

Native American People from both sides of the Columbia River utilized the islands on the Columbia River bordering the present-day states of Oregon and Washington, in the north central Columbia River Plateau region, for burials, as well as sites located along that river. Published ethnographic documentation indicates that this area was the aboriginal territory of the Western Columbia River Sahaptins, Wasco, Wishram, Yakima, Walla Walla, Umatilla, Tenino, and Skin (Daugherty 1973, Hale 1841, Hunn and French 1998, Stern 1998, French and French 1998, Mooney 1896, Murdock 1938, Ray 1936 and 1974, Spier 1936).

Cultural Affiliation

The human remains and associated funerary objects in this notice are connected to one or more identifiable earlier groups, tribes, peoples, or cultures. There is a relationship of shared group identity between the identifiable earlier groups, tribes, peoples, or cultures and one or more Indian Tribes or Native Hawaiian organizations. The following types of information were used to reasonably trace the relationship: geographical and historical.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after consultation with the appropriate Indian Tribes and Native Hawaiian organizations, the Wasco County/Dalles City Museum Commission has determined that:

- The human remains described in this notice represent the physical remains of three individuals of Native American ancestry.

- The seven objects described in this notice are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony.

- There is a relationship of shared group identity that can be reasonably traced between the human remains and associated funerary objects described in this notice and the Confederated Tribes and Bands of the Yakama Nation; Confederated Tribes of the Umatilla Indian Reservation; and the

Confederated Tribes of the Warm Springs Reservation of Oregon.

Requests for Repatriation

Written requests for repatriation of the human remains and associated funerary objects in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for repatriation may be submitted by:

1. Any one or more of the Indian Tribes or Native Hawaiian organizations identified in this notice.

2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the human remains and associated funerary objects in this notice to a requestor may occur on or after June 20, 2023. If competing requests for repatriation are received, the Wasco County/Dalles City Museum Commission must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the human remains and associated funerary objects are considered a single request and not competing requests. The Wasco County/Dalles City Museum Commission is responsible for sending a copy of this notice to the Indian Tribes identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.9, 10.10, and 10.14.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023-10554 Filed 5-17-23; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0035861; PPWOCRADN0-PCU00RP14.R50000]

Notice of Inventory Completion: Michigan State University, East Lansing, MI

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Michigan State University has completed an inventory of human remains and has determined that there is no cultural affiliation between the

human remains and any Indian Tribe. The human remains were removed from Kalamazoo County and unknown locations in MI.

DATES: Disposition of the human remains in this notice may occur on or after June 20, 2023.

ADDRESSES: Judith Stoddart, Associate Provost, University Arts and Collections, Michigan State University, 287 Delta Court, East Lansing, MI 48824, telephone (517) 432-2524, email stoddart@msu.edu.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of Michigan State University. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records held by Michigan State University.

Description

Human remains representing, at minimum, 16 individuals were removed from unknown locations in Michigan. These ancestors arrived at the Forensic Anthropology Laboratory (FAL) from police authorities and private citizens who had found human remains on their property. At some point, likely in the 1960s and 1970s, these ancestors were included in (former) teaching collections and disassociated from case and donation paperwork. As the FAL only accepts cases from within Michigan, these ancestors were most likely removed from Michigan. No associated funerary objects are present.

Human remains representing, at minimum, two individuals (catalog numbers 2007.77.4; 2007.77.5) were removed from Kalamazoo County, MI. On an unknown date, these individuals were acquired by Kalamazoo County resident, Donald Boudeman, who collected Native American material culture in the first half of the twentieth century. In 1961, Boudeman's wife, Donna Boudeman, donated the human remains together with Mr. Boudeman's collection to the Michigan State University Museum. Database records indicate these individuals were recovered from a mound near Vicksburg. No associated funerary objects are present.

Aboriginal Land

The human remains in this notice were removed from a known geographic location (Michigan). This location is the

aboriginal land of one or more Indian Tribes. The following information was used to identify the aboriginal land: treaties and a final judgment of the Indian Claims Commission or the United States Court of Claims.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after consultation with the appropriate Indian Tribes, Michigan State University has determined that:

- The human remains described in this notice represent the physical remains of 18 individuals of Native American ancestry.

- No relationship of shared group identity can be reasonably traced between the human remains and any Indian Tribe.

- The human remains described in this notice were removed from the aboriginal land of the Absentee-Shawnee Tribe of Indians of Oklahoma; Bad River Band of the Lake Superior Tribe of Chippewa Indians of the Bad River Reservation, Wisconsin; Bay Mills Indian Community, Michigan; Chippewa Cree Indians of the Rocky Boy's Reservation, Montana; Citizen Potawatomi Nation, Oklahoma; Delaware Nation, Oklahoma; Delaware Tribe of Indians; Eastern Shawnee Tribe of Oklahoma; Forest County Potawatomi Community, Wisconsin; Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Hannahville Indian Community, Michigan; Keweenaw Bay Indian Community, Michigan; Kickapoo Traditional Tribe of Texas; Kickapoo Tribe of Indians of the Kickapoo Reservation in Kansas; Kickapoo Tribe of Oklahoma; Lac Courte Oreilles Band of Lake Superior Chippewa Indians of Wisconsin; Lac du Flambeau Band of Lake Superior Chippewa Indians of the Lac du Flambeau Reservation of Wisconsin; Lac Vieux Desert Band of Lake Superior Chippewa Indians of Michigan; Little River Band of Ottawa Indians, Michigan; Little Shell Tribe of Chippewa Indians of Montana; Little Traverse Bay Bands of Odawa Indians, Michigan; Match-e-be-nash-she-wish Band of Pottawatomi Indians of Michigan; Menominee Indian Tribe of Wisconsin; Miami Tribe of Oklahoma; Minnesota Chippewa Tribe, Minnesota (Six component reservations: Bois Forte Band (Nett Lake); Fond du Lac Band; Grand Portage Band; Leech Lake Band; Mille Lacs Band; White Earth Band); Nottawaseppi Huron Band of the Potawatomi, Michigan; Ottawa Tribe of Oklahoma; Peoria Tribe of Indians of Oklahoma; Pokagon Band of Potawatomi Indians, Michigan and Indiana; Prairie Band Potawatomi

Nation; Red Cliff Band of Lake Superior Chippewa Indians of Wisconsin; Red Lake Band of Chippewa Indians, Minnesota; Sac & Fox Nation of Missouri in Kansas and Nebraska; Sac & Fox Nation, Oklahoma; Sac & Fox Tribe of the Mississippi in Iowa; Saginaw Chippewa Indian Tribe of Michigan; Sault Ste. Marie Tribe of Chippewa Indians, Michigan; Seneca Nation of Indians; Seneca-Cayuga Nation; Shawnee Tribe; Sokaogon Chippewa Community, Wisconsin; St. Croix Chippewa Indians of Wisconsin; Stockbridge Munsee Community, Wisconsin; Tonawanda Band of Seneca; Turtle Mountain Band of Chippewa Indians of North Dakota; and the Wyandotte Nation.

Requests for Disposition

Written requests for disposition of the human remains in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for disposition may be submitted by:

1. Any one or more of the Indian Tribes identified in this notice.
2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization, or who shows that the requestor is an aboriginal land Indian Tribe.

Disposition of the human remains described in this notice to a requestor may occur on or after June 20, 2023. If competing requests for disposition are received, Michigan State University must determine the most appropriate requestor prior to disposition. Requests for joint disposition of the human remains are considered a single request and not competing requests. Michigan State University is responsible for sending a copy of this notice to the Indian Tribes identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.9 and 10.11.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023-10556 Filed 5-17-23; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0035862; PPWOCRADNO-PCU00RP14.R50000]

Notice of Inventory Completion: Michigan State University, East Lansing, MI

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), Michigan State University has completed an inventory of human remains and associated funerary objects and has determined that there is a cultural affiliation between the human remains and associated funerary objects and Indian Tribes or Native Hawaiian organizations in this notice. The human remains and associated funerary objects were removed from Emmet County, MI. **DATES:** Repatriation of the human remains and associated funerary objects in this notice may occur on or after June 20, 2023.

ADDRESSES: Judith Stoddart, Michigan State University, 287 Delta Court, East Lansing, MI 48824, telephone (517) 432-2524, email stoddart@msu.edu.

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of Michigan State University. The National Park Service is not responsible for the determinations in this notice. Additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records held by Michigan State University.

Description

Human remains representing, at minimum, one individual were removed from Emmet County, MI. This individual arrived at Michigan State University as a police case in 1969 (Forensic Anthropology Lab (FAL) case number F.2.69), after a metal detectorist located the remains of a coffin burial along Five Mile Creek. The police removed human remains belonging to this individual, along with the associated funerary objects. After ancestry was determined to be Native American, the human remains and associated funerary objects were donated to Michigan State University (with a final donation date of 1971). In May of 1972, additional remains

belonging to this individual were recovered by the Michigan State Police and donated to MSU. The burial is believed to have been an extended burial, with the head pointing towards the west. Given the nails and wood, this coffin burial most likely dates between 1760 and 1820. After the analysis was complete, the human remains of this individual were stored with other forensic cases and the associated paperwork was filed (there were no computer database records of the analysis or final determination). This individual was mistaken for a cold case until 2022, when a reanalysis of several cold cases at the FAL prompted a re-investigation of this individual as well, at which time it was learned that the human remains had been previously identified as belonging to a Native American.

The 572 associated funerary objects are 40 silver brooch fragments, three brooch pins, 16 conical silver bobs, 28 silver balls, five silver loop fragments, two complete bangles, two tiered-and-faceted silver bobs, one complete teardrop bangle tied with fabric, 29 pieces of scrap metal, eight nail fragments with associated wood, eight scraps of loose fabric, 21 decorated silver band fragments (representing four distinct armbands), one amber bottle glass fragment, one burned glass fragment, one animal bone, one animal claw, one small bit of hair, three unidentified organic materials, two unidentified iron fragments, 25 pieces of scrap silver, six indigenous ceramic sherds, one piece of charcoal, one lot consisting of fly casings, one piece of fabric, 29 seed beads, and 336 assorted glass beads (brown doublet, tan doublet, faceted, dark green, brown, blue, white, amber).

Cultural Affiliation

The human remains and associated funerary objects in this notice are connected to one or more identifiable earlier groups, tribes, peoples, or cultures. There is a relationship of shared group identity between the identifiable earlier groups, tribes, peoples, or cultures and one or more Indian Tribes or Native Hawaiian organizations. The following types of information were used to reasonably trace the relationship: archeological, biological, geographical, and historical.

Determinations

Pursuant to NAGPRA and its implementing regulations, and after consultation with the appropriate Indian Tribes and Native Hawaiian organizations, Michigan State University has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.
- The 572 objects described in this notice are reasonably believed to have been placed with or near individual human remains at the time of death or later as part of the death rite or ceremony.
- There is a relationship of shared group identity that can be reasonably traced between the human remains and associated funerary objects described in this notice and the Grand Traverse Band of Ottawa and Chippewa Indians, Michigan; Little River Band of Ottawa Indians, Michigan; Little Traverse Bay Bands of Odawa Indians, Michigan; and the Ottawa Tribe of Oklahoma.

Requests for Repatriation

Written requests for repatriation of the human remains and associated funerary objects in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for repatriation may be submitted by:

1. Any one or more of the Indian Tribes or Native Hawaiian organizations identified in this notice and, if joined to a request from one or more of the Indian Tribes, any one or more of the following non-federally recognized Indian groups: the Burt Lake Band of Ottawa and Chippewa Indians and the Grand River Band of Ottawa Indians.
2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the human remains and associated funerary objects in this notice to a requestor may occur on or after June 20, 2023. If competing requests for repatriation are received, Michigan State University must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the human remains and associated funerary objects are considered a single request and not competing requests. Michigan State University is responsible for sending a copy of this notice to the Indian Tribes identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.9, 10.10, and 10.14.

Dated: May 10, 2023.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2023–10557 Filed 5–17–23; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

[Docket No. OSHA–2010–0051]

The Manlifts Standard; Extension of the Office of Management and Budget's (OMB) Approval of Information Collection (Paperwork) Requirements

AGENCY: Occupational Safety and Health Administration (OSHA), Labor.

ACTION: Request for public comments.

SUMMARY: OSHA solicits public comments concerning the proposal to extend the Office of Management and Budget's (OMB) approval of the information collection requirements specified in the Manlifts Standard.

DATES: Comments must be submitted (postmarked, sent, or received) by July 17, 2023.

ADDRESSES:

Electronically: You may submit comments and attachments electronically at <http://www.regulations.gov>, which is the Federal eRulemaking Portal. Follow the instructions online for submitting comments.

Docket: To read or download comments or other material in the docket, go to <http://www.regulations.gov>. Documents in the docket are listed in the <http://www.regulations.gov> index; however, some information (e.g., copyrighted material) is not publicly available to read or download through the website. All submissions, including copyrighted material, are available for inspection through the OSHA Docket Office. Contact the OSHA Docket Office at (202) 693–2350 (TTY (877) 889–5627) for assistance in locating docket submissions.

Instructions: All submissions must include the agency name and OSHA docket number (OSHA–2010–0051) for the Information Collection Request (ICR). OSHA will place all comments, including any personal information, in the public docket, which may be made available online. Therefore, OSHA cautions interested parties about submitting personal information such as social security numbers and birthdates.

For further information on submitting comments, see the “Public

Participation” heading in the section of this notice titled **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT:

Seleda Perryman or Theda Kenney, Directorate of Standards and Guidance, OSHA, U.S. Department of Labor; telephone (202) 693–2222.

SUPPLEMENTARY INFORMATION:

I. Background

The Department of Labor, as part of the continuing effort to reduce paperwork and respondent (*i.e.*, employer) burden, conducts a preclearance consultation program to provide the public with an opportunity to comment on proposed and continuing information collection requirements in accordance with the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3506(c)(2)(A)). This program ensures that information is in the desired format, reporting burden (time and costs) is minimal, the collection instruments are clearly understood, and OSHA's estimate of the information collection burden is accurate. The Occupational Safety and Health Act of 1970 (OSH Act) (29 U.S.C. 651 *et seq.*) authorizes information collection by employers as necessary or appropriate for enforcement of the OSH Act or for developing information regarding the causes and prevention of occupational injuries, illnesses, and accidents (29 U.S.C. 657). The OSH Act also requires that OSHA obtain such information with minimum burden upon employers, especially those operating small businesses, and to reduce to the maximum extent feasible unnecessary duplication of effort in obtaining information (29 U.S.C. 657).

The Manlifts Standard (29 CFR 1910.68(e)) specifies two paperwork requirements. The following sections describe who uses the information collected under each requirement, as well as how they use it. The purpose of the requirements is to reduce workers' risk of death or serious injury by ensuring that manlifts are in safe operating condition.

Periodic Inspections and Records (Paragraph (e))

This provision requires that each manlift be inspected at least once every 30 days and it also requires that limit switches shall be checked weekly. The manlift inspection is to cover at least the following items: steps; step fastenings; rails; rail supports and fastenings; rollers and slides; belt and belt tension; handholds and fastenings; floor landings; guardrails; lubrication; limit switches; warning signs and lights;

illumination; drive pulley; bottom (boot) pulley and clearance; pulley supports; motor; driving mechanism; brake; electrical switches; vibration and misalignment; and any “skip” on the up or down run when mounting a step (indicating worn gears). A certification record of the inspection must be prepared upon completion of the inspection. The record must contain the date of the inspection, the signature of the person who performed the inspection, and the serial number or other identifier of the inspected manlift.

Disclosure of Inspection Certification Records

Employers are to maintain the certification record and make it available to OSHA compliance officers. This record provides assurance to employers, workers, and compliance officers that manlifts were inspected as required by the Standard. The inspections are made to keep equipment in safe operating condition thereby preventing manlift failure while carrying workers to elevated worksites. These records also provide the most efficient means for the compliance officers to determine that an employer is complying with the Standard.

II. Special Issues for Comment

OSHA has a particular interest in comments on the following issues:

- Whether the proposed information collection requirements are necessary for the proper performance of the agency's functions to protect workers, including whether the information is useful;
- The accuracy of OSHA's estimate of the burden (time and costs) of the information collection requirements, including the validity of the methodology and assumptions used;
- The quality, utility, and clarity of the information collected; and
- Ways to minimize the burden on employers who must comply; for example, by using automated or other technological information collection, and transmission techniques.

III. Proposed Actions

OSHA is requesting that OMB extend the approval of the information collection requirements contained in the Manlifts Standard (29 CFR 1910.68(e)). The agency is requesting to retain the estimated burden of 37,800 hours. The total number of responses remains the same at 36,000 for the number of inspections certifications maintained annually.

OSHA will summarize the comments submitted in response to this notice and will include this summary in the

request to OMB to extend the approval of the information collection requirements.

Type of Review: Extension of a currently approved collection.

Title: The Manlifts Standard (29 CFR 1910.68(e)).

OMB Control Number: 1218–0226.

Affected Public: Business or other for-profits.

Number of Respondents: 3,000.

Number of Responses: 36,000.

Frequency of Responses: On occasion.

Average Time per Response: Varies.

Estimated Total Burden Hours: 37,800.

Estimated Cost (Operation and Maintenance): \$0.

IV. Public Participation—Submission of Comments on This Notice and Internet Access to Comments and Submissions

You may submit comments in response to this document as follows: (1) electronically at <http://www.regulations.gov>, which is the Federal eRulemaking Portal; (2) by facsimile (fax); if your comments, including attachments, are not longer than 10 pages you may fax them to the OSHA Docket Office at 202–693–1648; or (3) by hard copy. All comments, attachments, and other material must identify the agency name and the OSHA docket number for the ICR (Docket No. OSHA–2010–0051). You may supplement electronic submissions by uploading document files electronically.

Comments and submissions are posted without change at <http://www.regulations.gov>. Therefore, OSHA cautions commenters about submitting personal information such as social security numbers and dates of birth. Although all submissions are listed in the <http://www.regulations.gov> index, some information (e.g., copyrighted material) is not publicly available to read or download from this website. All submissions, including copyrighted material, are available for inspection and copying at the OSHA Docket Office. Information on using the <http://www.regulations.gov> website to submit comments and access the docket is available at the website's “User Tips” link.

Contact the OSHA Docket Office at (202) 693–2350, (TTY) (877) 889–5627 for information about materials not available from the website, and for assistance in using the internet to locate docket submissions.

V. Authority and Signature

James S. Frederick, Deputy Assistant Secretary of Labor for Occupational Safety and Health, directed the preparation of this notice. The authority

for this notice is the Paperwork Reduction Act of 1995 (44 U.S.C. 3506 *et seq.*) and Secretary of Labor's Order No. 8–2020 (85 FR 58393).

Signed at Washington, DC, on May 11, 2023.

James S. Frederick,

Deputy Assistant Secretary of Labor for Occupational Safety and Health.

[FR Doc. 2023–10567 Filed 5–17–23; 8:45 am]

BILLING CODE 4510–26–P

DEPARTMENT OF LABOR

Veterans' Employment and Training Service

Advisory Committee on Veterans' Employment, Training and Employer Outreach (ACVETEO); Meeting

AGENCY: Veterans' Employment and Training Service (VETS), Department of Labor (DOL).

ACTION: Notice of open meeting.

SUMMARY: This notice sets forth the schedule and proposed agenda of a forthcoming meeting of the ACVETEO. The ACVETEO will discuss the DOL core programs and services that assist veterans seeking employment and raise employer awareness as to the advantages of hiring veterans. There will be an opportunity for individuals or organizations to address the committee. Any individual or organization that wishes to do so should contact Mr. Gregory Green at ACVETEO@dol.gov. Additional information regarding the Committee, including its charter, current membership list, annual reports, meeting minutes, and meeting updates may be found at <https://www.dol.gov/agencies/vets/about/advisorycommittee>. This notice also describes the functions of the ACVETEO.

DATES: Thursday, June 8, 2023 beginning at 9 a.m. and ending at approximately 12 p.m. (EDT).

ADDRESSES: This ACVETEO meeting will be held via TEAMS and teleconference. Meeting information will be posted at the link below under the Meeting Updates tab. <https://www.dol.gov/agencies/vets/about/advisorycommittee>.

Notice of Intent to Attend the Meeting: All meeting participants should submit a notice of intent to attend by Friday, May 26, 2023, via email to Mr. Gregory Green at ACVETEO@dol.gov, subject line “June 2023 ACVETEO Meeting.” Individuals who will need accommodations for a disability in order to attend the meeting (e.g., interpreting services, assistive listening devices, and/or materials in alternative format)

should notify the Advisory Committee no later than Friday, May 26, 2023, by contacting Mr. Gregory Green at ACVETEO@dol.gov.

Requests made after this date will be reviewed, but availability of the requested accommodations cannot be guaranteed.

FOR FURTHER INFORMATION CONTACT: Mr. Gregory Green, Designated Federal Official for the ACVETEO, ACVETEO@dol.gov, (202) 693-4734.

SUPPLEMENTARY INFORMATION: The ACVETEO is a Congressionally mandated advisory committee authorized under title 38, U.S. Code, section 4110 and subject to the Federal Advisory Committee Act, 5 U.S.C. 10. The ACVETEO is responsible for: assessing employment and training needs of veterans; determining the extent to which the programs and activities of the U.S. Department of Labor meet these needs; assisting to conduct outreach to employers seeking to hire veterans; making recommendations to the Secretary, through the Assistant Secretary for Veterans' Employment and Training Service, with respect to outreach activities and employment and training needs of veterans; and carrying out such other activities necessary to make required reports and recommendations. The ACVETEO meets at least quarterly.

Agenda

- 9:00 a.m. Welcome and remarks, James D. Rodriguez, Assistant Secretary, Veterans' Employment and Training Service
- 9:10 a.m. Administrative Business, Gregory Green, Designated Federal Official
- 9:15 a.m. Service Delivery Subcommittee update
- 10:00 a.m. Break
- 10:15 a.m. Underserved Population Subcommittee update
- 11:00 a.m. Innovative Veteran Training and Employment Subcommittee update
- 11:45 p.m. Public Forum, Gregory Green, Designated Federal Official
- 12:00 p.m. Adjourn

Notice of this meeting is required under section 10(a)(2) of the Federal Advisory Committee Act. This document is intended to notify the general public.

Signed in Washington, DC, this 11th day of May 2023.

James D. Rodriguez,
Assistant Secretary, Veterans' Employment and Training Service.

[FR Doc. 2023-10571 Filed 5-17-23; 8:45 am]

BILLING CODE 4510-79-P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice: 23-053]

Name of Information Collection: Software Catalog

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Notice of information collection.

SUMMARY: The National Aeronautics and Space Administration, 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 proposed and/or continuing information collections.

DATES: Comments are due by June 20, 2023.

ADDRESSES: Written comments and recommendations for this 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.

FOR FURTHER INFORMATION CONTACT:

Requests for additional information or copies of the information collection instrument(s) and instructions should be directed to Bill Edwards-Bodmer, NASA Clearance Officer, NASA Headquarters, 300 E Street SW, JF0000, Washington, DC 20546, 757-864-7998, or b.edwards-bodmer@nasa.gov.

SUPPLEMENTARY INFORMATION:

I. Abstract

The information submitted by government entities, companies, academic institutions, and individuals is a software request form who wish to obtain a Software Usage Agreement (SUA) for a released NASA software technology. At a minimum, all software requestors must submit the intended use of the software and the requestor's citizenship, country of residence, phone number, and address. The collected information is used by NASA to ensure that the software requestor meets the qualifications to receive the NASA software technology.

II. Methods of Collection

NASA is participating in Federal efforts to extend the use of information technology to more Government processes via internet. NASA encourages recipients to use the latest computer technology in preparing documentation. Government entities, companies, academic institutions, and

individuals submit software requests by completing the automated form by way of the Software Catalog. NASA requests all software requests to be submitted via electronic means.

III. Data

Title: Software Catalog.

OMB Number:

Type of review: New.

Affected Public: Government entities, companies, academic institutions, and individuals.

Estimated Annual Number of Activities: 1.

Estimated Number of Respondents per Activity: 1,171.

Annual Responses: 1,171.

Estimated Time per Response: 8 hours.

Estimated Total Annual Burden Hours: 9,368.

Estimated Total Annual Cost: \$361,698.

IV. Request for Comments

Comments are invited on: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of NASA, including whether the information collected has practical utility; (2) the accuracy of NASA's estimate of the burden (including hours and cost) of the proposed collection of information; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including automated collection techniques or the use of other forms of information technology.

Comments submitted in response to this notice will be summarized and included in the request for OMB approval of this information collection. They will also become a matter of public record.

William Edwards-Bodmer,
NASA PRA Clearance Officer.

[FR Doc. 2023-10628 Filed 5-17-23; 8:45 am]

BILLING CODE 7510-13-P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice: 23-052]

Name of Information Collection: Automated Technology Licensing Application System (ATLAS)

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Notice of extension of information collection.

SUMMARY: The National Aeronautics and Space Administration, 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 proposed and/or continuing information collections.

DATES: Comments are due by June 20, 2023.

ADDRESSES: Written comments and recommendations for this 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.

FOR FURTHER INFORMATION CONTACT:

Requests for additional information or copies of the information collection instrument(s) and instructions should be directed to Bill Edwards-Bodmer, NASA Clearance Officer, NASA Headquarters, 300 E Street SW, JF0000, Washington, DC 20546, 757-864-7998, or b.edwards-bodmer@nasa.gov.

SUPPLEMENTARY INFORMATION:

I. Abstract

The information submitted by the public is a license application for those companies and individuals who wish to obtain a patent license for a NASA patented technology. Information needed for the license application in ATLAS may include supporting documentation such as a certificate of incorporation, a financial statement, a business and/or commercialization plan, a project revenue/royalty spreadsheet, and a company balance sheet. At a minimum, all license applicants must submit a satisfactory plan for the development and/or marketing of an invention. The collected information is used by NASA to ensure that companies that see to commercialize NASA technologies have a solid business plan for bringing the technology to market.

II. Methods of Collection

NASA is participating in Federal efforts to extend the use of information technology to more Government processes via internet. NASA encourages recipients to use the latest computer technology in preparing documentation. Companies and individuals submit license applications by completing the automated form by way of the Automated Technology Licensing Application System (ATLAS). NASA requests all license applications to be submitted via electronic means.

III. Data

Title: Automated Technology Licensing Application System (ATLAS).

OMB Number: 2700-0169.

Type of review: Extension.

Affected Public: Public and companies.

Estimated Annual Number of Activities: 1.

Estimated Number of Respondents per Activity: 421.

Annual Responses: 421.

Estimated Time per Response: 8 hours.

Estimated Total Annual Burden Hours: 3,368.

Estimated Total Annual Cost: \$130,038.

IV. Request for Comments

Comments are invited on: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of NASA, including whether the information collected has practical utility; (2) the accuracy of NASA's estimate of the burden (including hours and cost) of the proposed collection of information; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including automated collection techniques or the use of other forms of information technology.

Comments submitted in response to this notice will be summarized and included in the request for OMB approval of this information collection. They will also become a matter of public record.

William Edwards-Bodmer,
NASA PRA Clearance Officer.

[FR Doc. 2023-10629 Filed 5-17-23; 8:45 am]

BILLING CODE 7510-13-P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice: 23-051]

Request for Information: NASA Public Access Plan for Increasing Access to the Results of NASA-Supported Research

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Request for information (RFI); notice of comment period.

SUMMARY: NASA seeks public input on the "NASA's Public Access Plan, Increasing Access to the Results of Scientific Research" (NASA Public Access Plan). NASA has a decades-long history of providing public access to

scholarly publications and data resulting from the research it supports, including through the 2014 Open Access Plan. In 2022, the White House Office of Science and Technology Policy (OSTP) released a memorandum on "Ensuring Free, Immediate, and Equitable Access to Federally Funded Research" that establishes new guidance for improving public access to scholarly publications and data resulting from Federally supported research. The NASA Public Access Plan outlines the proposed approach NASA will take to implement the new guidance, consistent with its longstanding commitment to public access.

DATES: For the request for information published on May 18, 2023, submit comments by August 17, 2023. Early comments are encouraged. Comments received after this date will be considered to the extent practicable.

ADDRESSES: All responses to this RFI must be submitted in an electronic format only via the email mailbox: hq-publicaccess@mail.nasa.gov.

- *Mail:* Comments submitted in a manner other than the one listed above, including emails or letters sent to NASA, OCS, SMD, or other NASA officials may not be accepted.

- *Hand Delivery:* Please note that NASA cannot accept any comments that are hand delivered or couriered. In addition, NASA cannot accept comments contained on any form of digital media storage devices, such as CDs/DVDs and USB drives.

FOR FURTHER INFORMATION CONTACT:

Issues regarding clarifications or questions on this RFI can be sent to Dr. Louis Barbier, NASA Associate Chief Scientist, at Louis.M.Barbier@nasa.gov, 202-358-1421.

Issued by Office of The Chief Scientist, National Aeronautics and Space Administration

SUPPLEMENTARY INFORMATION:

I. Background

NASA has a long-standing culture of promoting the full and open sharing of data with the research communities, private industry, academia, and the general public. NASA space and airborne missions routinely process, archive, and distribute their data to researchers around the globe. Data from all NASA spacecraft are currently available through the individual mission and theme archives. Through NASA's 2014 Open Access Plan NASA responded to OSTP's call for open access to peer-reviewed scientific publications albeit with an embargo period not to exceed 12 months. That plan also called on NASA researchers to

submit a Data Management Plan along with their proposals to ensure long-term stewardship of federally funded data.

Increasing access to publications and data resulting from federally funded research offers many benefits to the scientific community and the public. Access can accelerate research, generate higher quality scientific results, encourage greater scientific integrity, and enable future inquiry, discovery, and translation for scientific research. Importantly, these efforts also uphold NASA's commitment to responsible stewardship of the Nation's investment in biomedical research by improving transparency and accessibility of taxpayer-funded research.

NASA efforts align with public access directives, policies, and programs across the U.S. Government. Since 2013, federal public access policy has been guided by the OSTP *Memorandum on Increasing Access to the Results of Federally Funded Research*, which directed all federal departments and agencies with more than \$100 million in annual research and development expenditures to develop a plan to support increased public access to scholarly publications and digital data resulting from federally funded research. On August 25, 2022, OSTP released updated policy guidance (2022 OSTP *Memorandum*) that focuses on accelerated access to scholarly publications (most notably, by removing the currently allowable 12-month embargo period for free access), increased access to scientific data, and enhanced tracking of research products through persistent identifiers (PIDs) and metadata.

The NASA Public Access Plan provides a roadmap for how NASA proposes to accelerate access to scholarly publications, scientific data, and software and will help ensure these research products are findable and equitably accessible to support further scientific discovery. NASA plans to modify implementation of the NASA Public Access Policy to accommodate novel elements of the 2022 OSTP *Memorandum* related to scholarly publications.

NASA looks forward to working across the U.S. Government to support our shared commitment to responsible stewardship of the Nation's investment in biomedical research by improving transparency and accessibility of taxpayer-funded research.

Request for Information

NASA's Public Access Plan

(https://www.nasa.gov/sites/default/files/atoms/files/nasa_ocs_public_

[access_plan_may_2023.pdf](#)) is now being released for a period of public comment. The plan adheres to NASA's principles surrounding open access, in part:

- Open Access to federally-funded scientific research has the potential to increase the pace of scientific discovery, advance technology development, speed up exploration, and promote more efficient and effective use of government funding and resources.

- Sharing and preserving publications, data, and software are central to protecting the integrity of science by facilitating validation of results, as well as advancing science by broadening the value of research data to disciplines other than the originating one and to society at large.

II. Discussion of Questions

The NASA Public Access plan also goes beyond the OSTP memorandum and calls for open access to software as well, in keeping with the Transition to Open Science (TOPS) which NASA is proudly pioneering for the federal government.

NASA seeks information regarding the NASA Public Access Plan from all interested individuals and communities, including, but not limited to, authors, investigators, research institutions, libraries, scholarly publishers, scientific societies, healthcare providers, patients, students, educators, research participants, and other members of the public. While comments are welcome on all elements of the NASA Public Access Plan, input would be most welcome on the particular issues identified below.

1. How to best ensure equity in publication opportunities for NASA-supported investigators. The NASA Public Access Plan aims to maintain the existing broad discretion for researchers and authors to choose how and where to publish their results. Consistent with current practice, the NASA Public Access Plan allows the submission of final published articles to Clearinghouse for the Open Research of the United States (CHORUS), the NASA Scientific, Technical and Research Information discoVEry System (STRIVES), Astrophysics Data System (ADS), or NASA's PubSpace to minimize the compliance burden on NASA-supported researchers. These submission routes are allowed regardless of whether or not the journal uses an open access model, a subscription model of publishing, or other publication model. This flexibility aims to protect against concerns that have been raised about certain publishing models potentially disadvantaging early career researchers

and researchers from limited-resourced institutions or under-represented groups. NASA policy allows supported researchers to charge reasonable publishing costs against their awards. NASA seeks information on additional steps it might consider taking to ensure that proposed changes to implementation of the Public Access Policy do not create new inequities in publishing opportunities or reinforce existing ones.

2. Steps for improving equity in access and accessibility of publications. Removal of the currently allowable 12-month embargo period for NASA-supported publications will improve access to these research products for all. The NASA Public Access Plan also supports making articles available in human and machine-readable forms to support automated text processing. NASA will also seek ways to improve the accessibility of publications by diverse communities of users.

3. Methods for monitoring evolving costs and impacts on affected communities. NASA proposes to actively monitor trends in publication fees and policies to ensure that they remain reasonable and equitable. NASA seeks information on effective approaches for monitoring trends in publication fees and equity in publication opportunities.

4. Input on considerations to increase findability and transparency of research. NASA seeks suggestions on any specific issues that should be considered in efforts to improve use of PIDs (such as ORCID) and metadata, including information about experiences institutions and researchers have had with adoption of different identifiers.

5. Suggestions on sharing and archiving of software. Sites like GitHub and Zenodo offer ways to distribute and manage software. NASA is seeking suggestions on improving the archiving, sharing, and maintenance of software for reuse.

III. Written Responses

Responses to this RFI are voluntary and may be submitted anonymously. You may also voluntarily include your name and contact information with your response. Other than your name and contact information, please do not include in the response any personally identifiable information or any information that you do not wish to make public. Proprietary, classified, confidential, or sensitive information should not be included in your response.

Written responses should be in a PDF file attached to the email submission, not to exceed 4 pages, excluding a cover

page and any references. You may respond to some or all questions listed in the RFI. There is no limit on the number of responses from an individual or an institution or its organizational units.

IV. Review of Public Feedback

After the Office of the Chief Scientist (OCS) has finished reviewing the responses, the responses may be posted to the NASA OCS website without redaction. All submissions will be acknowledged and NASA will publicize a summary of the submissions within 90 days.

Cheryl Parker,

Federal Register Liaison Officer.

[FR Doc. 2023-10643 Filed 5-17-23; 8:45 am]

BILLING CODE 7510-13-P

NUCLEAR REGULATORY COMMISSION

[Docket No. 70-7005; NRC-2022-0093]

Waste Control Specialists LLC

AGENCY: Nuclear Regulatory Commission.

ACTION: Environmental assessment and finding of no significant impact; issuance.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is issuing an Environmental Assessment (EA) and Finding of No Significant Impact (FONSI) in support of the NRC's consideration of a June 30, 2022, Waste Control Specialists LLC (WCS) request for a superseding Order to its current (2014) NRC Order (as supplemented by subsequent NRC letters to WCS from 2016 to 2022). In its letter, WCS requested authorization to (1) move the U.S. Department of Energy (DOE) Los Alamos National Laboratory (LANL) Waste at the WCS Site from its current location at the WCS Federal Waste Facility (FWF) disposal cell to another location at the WCS Site, the WCS Treatment, Storage, and Disposal Facility (TSDF) Bin Storage Area (BSA)—1 Enclosure, (2) prepare the LANL Waste in the WCS TSDF BSA—1 Enclosure for shipment (e.g., replace lifting straps for Standard Waste Boxes (SWBs), replace filter vents in SWBs, perform borescope in SWBs, take air samples from head space in SWBs), and (3) temporarily store the LANL Waste in the WCS TSDF BSA—1 Enclosure until the DOE ships the LANL Waste off the WCS Site to a future DOE determined location, which is currently expected to be either the DOE LANL or the DOE

Waste Isolation Pilot Plant (WIPP) Facility.

DATES: The EA and FONSI referenced in this document are available on May 18, 2023.

ADDRESSES: Please refer to Docket ID NRC-2022-0093 when contacting the NRC about the availability of information regarding this document. You may obtain publicly available information related to this document using any of the following methods:

- *Federal Rulemaking Website:* Go to <http://www.regulations.gov> and search for Docket ID NRC-2022-0093. Address questions about Docket IDs to Stacy Schumann; telephone: 301-415-0624; email: Stacy.Schumann@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 <http://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, 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 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 a.m. and 4 p.m. eastern time (ET), Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: James Park, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; telephone: 301-415-6954; email: James.Park@nrc.gov.

SUPPLEMENTARY INFORMATION:

I. Introduction

WCS operates a site in Andrews County, Texas, that is licensed to process and store certain types of radioactive material contained in low-level radioactive waste (LLRW) and mixed waste (MW) (waste that is both hazardous waste and LLRW). The WCS Site also disposes of hazardous and

toxic waste. Under an Agreement authorized by the Atomic Energy Act of 1954, as amended (AEA), the NRC can relinquish, and a state can assume, regulatory authority over radioactive material specified in an Agreement with NRC. In 1963, Texas entered into such an Agreement with the NRC's predecessor agency, the Atomic Energy Commission, and assumed regulatory authority over source material, byproduct material, and special nuclear material (SNM) under a critical mass. In 1982, the NRC and Texas amended the Agreement to permit Texas to continue to regulate byproduct material as defined in section 11e.(2) of the AEA (uranium mill tailings) in conformance with the requirements of section 274o. of the AEA.

On November 30, 1997, the State of Texas Department of Health (TDH) issued WCS a radioactive materials license (RML) to possess, treat, and store LLRW (RML R04971). In 1997, WCS began accepting Resource Conservation and Recovery Act (RCRA) and Toxic Substance Control Act wastes for treatment, storage, and disposal. Later that year, WCS received a license from the TDH for treatment and storage of MW and LLRW. The MW and LLRW streams may contain quantities of SNM. In 2007, RML R04971 was transferred to the Texas Commission on Environmental Quality (TCEQ). In September 2009, TCEQ issued RML R04100 to WCS for disposal of LLRW. In May 2013, R04971 was merged into license R04100 in amendment 22 to license R04100.

Section 70.3 of title 10 of *Code of Federal Regulations* (10 CFR), "License requirements," requires persons who own, acquire, deliver, receive, possess, use, or transfer SNM to obtain a license pursuant to the requirements of 10 CFR part 70, "Domestic Licensing of Special Nuclear Material." The licensing requirements in 10 CFR part 70 apply to persons in Agreement States possessing greater than critical mass quantities (Agreement States can regulate material below this quantity under their agreement), as defined in 10 CFR 150.11, "Critical Mass." Pursuant to 10 CFR 70.17(a), "the Commission may, upon application of any interested person or upon its own initiative, grant such exemptions from the requirements of the regulations in this part as it determines are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest."

In September 2000, WCS requested an exemption from the licensing requirements in 10 CFR part 70. On November 21, 2001, the NRC issued an

Order to WCS (2001 Order) granting an exemption to WCS from certain NRC regulations and authorizing WCS, under specified conditions, to possess waste containing SNM in greater quantities than specified in 10 CFR part 150, "Exemptions and Continued Regulatory Authority in Agreement States and in Offshore Waters under Section 274," at the WCS storage and treatment facility without obtaining an NRC license pursuant to 10 CFR part 70. The 2001 Order was published in the **Federal Register** on November 15, 2001 (66 FR 57489). Subsequent superseding orders were issued in 2004, 2009, and 2014. The 2014 Order is currently in effect.

The 2014 NRC Order to WCS contains conditions that allow WCS to possess and temporarily store DOE LANL Waste at two locations at the WCS Site, the FWF disposal cell and the WCS TSDF,¹ without obtaining an NRC part 70 license. The LANL Waste is transuranic waste with SNM that originated from LANL and was destined for disposal at the DOE Waste Isolation Pilot Plant Facility in New Mexico. The conditions in the 2014 Order were modified by five NRC letters to WCS dated September 23, 2016, September 26, 2017, December 19, 2018, December 7, 2020, and June 8, 2022.

By letter dated June 30, 2022, as supplemented by clarification calls, WCS requested a superseding order to: (1) move the DOE LANL Waste from the FWF to the WCS TSDF BSA-1 Enclosure, (2) prepare the LANL Waste in the WCS TSDF BSA-1 Enclosure for shipment (*e.g.*, replace lifting straps for SWBs, replace filter vents in SWBs, perform borescope in SWBs, take air samples from head space in SWBs), and (3) temporarily store the LANL Waste in the WCS TSDF BSA-1 Enclosure until the DOE ships the LANL Waste off the WCS Site to a DOE determined location, which is currently expected to be either the DOE LANL or the DOE WIPP Facility.

To begin the activities necessary to move the LANL Waste from the FWF disposal cell to the WCS TSDF BSA-1 Enclosure, WCS would dismantle the shade structure in the FWF and remove the temperature monitoring leads to the 35 Modular Concrete Canisters (MCCs) that contain the 74 SWBs. Then to access the MCCs, WCS would use heavy equipment (*e.g.*, back-hoe, dump truck) to remove the bulk of the sand layer covering the MCCs. After negative confirmatory radiation surveys, WCS

would remove the remaining sand around the MCC lids by hand. As the MCCs are exposed, WCS would also perform inspections and radiation surveys of the exterior surfaces of the canisters. If the survey results are favorable, WCS next would remove the MCC covers, and perform another radiation survey of the exposed surfaces. Should the radiological surveys reveal contamination, WCS would halt excavation of the MCC and determine next steps pursuant to the draft Documented Safety Analysis in the WCS request.

Once the MCC lid is removed, WCS would take the temperature of the pea gravel within the MCC. Temperatures above 37.8 degrees Celsius (100 degrees Fahrenheit) would be considered for additional monitoring, with temperatures above 57.2 degrees Celsius (135 degrees Fahrenheit) indicating that an exothermic reaction could be occurring. WCS next would check for the presence of water above the level of the pea gravel within each MCC. WCS would remove any water found and take it to the WCS TSDF to be sampled, treated, and disposed as appropriate.

With these activities completed, WCS would remove the MCCs from the FWF disposal cell, one at a time, using Kalmar lifting and handling equipment that has been specifically adapted to WCS's needs. With the MCC lid removed, the Kalmar connects to the MCC via lifting cables that attach to the interior rim of the canister. The Kalmar then would transport each MCC to the top of the FWF disposal cell, where the MCC would be loaded on a Goldhofer remote-controlled transport trailer for transfer to the BSA-1 Enclosure. The Goldhofer can transport two MCCs at a time. The MCC lids would be replaced for the transfer.

In the draft Documented Safety Analysis provided in WCS's request, the WCS TSDF BSA-1 Enclosure would be the primary control measure and barrier in the event of an unlikely release of radioactive material once the material is emplaced there. As such, it is an enclosed containment structure equipped with a high efficiency particulate air (HEPA) ventilation system to maintain the structure at a negative pressure and with a Heating, Ventilation, and Air Conditioning (HVAC) system to keep the Enclosure temperature-controlled during the movement, inspection, and handling of the SWBs and material within. To meet these needs, WCS would construct a polyvinyl chloride Architectural Membrane Tent within the WCS TSDF; the Bin Storage Area 1 Enclosure.

On arrival at the WCS TSDF BSA-1, WCS would either (1) move the Goldhofer into the Enclosure or (2) move each MCC from the Goldhofer to another WCS vehicle and move that vehicle into the Enclosure, where continuous air monitors would be used to sample the air. WCS again would remove the MCC lid, and a vacuum system equipped with a HEPA filtration system would be used to remove the pea gravel and any water found in the MCC.

WCS would sample the sand removed in the FWF from around the MCCs, any water found within an MCC, and the pea gravel removed from the MCCs. Depending on the sampling results, WCS would either dispose of these secondary wastes in the onsite RCRA Subtitle C landfill, if appropriate, (the water would need to be solidified before doing so) or request TCEQ approval for disposal in the FWF.

As the SWBs within the MCC are exposed, WCS would perform a visual inspection for any damage or defects and check the temperature of the SWB for elevated readings. Once the pea gravel has been removed to the extent practicable around the top tier of SWBs, WCS would replace, as needed, the original lifting straps that had been used to emplace the SWBs in the MCC with new straps. WCS would next remove the SWBs in turn from each MCC, using a hoist in the overhead gantry system and then move them to a temperature-controlled laydown area where they would be radiologically surveyed and inspected. In the laydown area, WCS would replace and/or add, as needed, the filter vents on each of the SWBs. WCS would also conduct a borescope inspection of the SWBs through a filter hole and take air samples from the head space within the SWB during the borescope inspection.

II. Environmental Assessment

Description of the Proposed Action

The proposed action is whether to grant the WCS June 30, 2022, request to modify the conditions of the 2014 Order to reflect the actions WCS would take in moving the LANL Waste from temporary storage at the FWF disposal cell to temporary storage in the WCS TSDF BSA-1 Enclosure, preparing the LANL Waste for DOE shipment off the WCS Site, and storing the LANL Waste in the WCS TSDF BSA-1 Enclosure until it is shipped offsite.

Need for the Proposed Action

WCS is making this request so that a new superseding Order to WCS would reflect the actions that WCS would take to move, prepare for shipment, and store

¹ For the purposes of the EA and FRN, "WCS TSDF" refers to the area on the WCS Site in Andrews County, Texas where WCS intends to perform the prepare for shipment activities and temporarily store the LANL Waste.

the LANL Waste at a different location at WCS.

The purpose of this EA is to assess the potential environmental impacts of the proposed WCS actions. This EA does not approve or deny the requested action. A separate safety evaluation report is being prepared in support of the NRC's consideration of this action.

Environmental Impacts of the Proposed Action

The NRC does not expect significant changes in radiation hazards to workers as the MCCs containing the LANL Waste are exposed in the FWF disposal cell and then moved from the FWF disposal cell to the WCS TSDF BSA-1 Enclosure and as the SWBs are removed from the MCCs and placed in temporary storage in the BSA-1 Enclosure. WCS has in place a Radiation Safety Program to ensure every reasonable effort to maintain exposures to radiation from occupational exposures is as far below the dose limits as is reasonable (Radiation Safety Program), and that program serves as a primary confirmation of the adequacy of the active operational controls and the passive engineering controls for monitoring and prevention of releases. For example, during the proposed activities to move the LANL Waste from the FWF disposal cell to the WCS TSDF BSA-1 Enclosure, WCS would conduct radiological surveys and inspections to protect workers and to keep potential doses as low as reasonably achievable (ALARA). Further, the LANL Waste at the WCS Site is subject to WCS's material control and accounting and security programs that the NRC staff has previously evaluated and found adequate to protect against nuclear criticality, or material theft or diversion.

If the WCS exemption request is approved by the NRC staff, then the NRC would issue a new order that would supersede the 2014 Order. In the new order, Conditions 1 through 7 would remain the same as in the 2014 Order, new Condition 8 would be created to reflect the NRC letters to WCS from 2016 to 2022, Conditions 8.A. and 8.B. from the 2014 Order would be renumbered as new Conditions 9.A. and 9.B reflecting the NRC letters to WCS from 2016 to 2022, and a new Condition 9.C and 9.D would be added to address WCS's exemption request. The new Condition 9 would apply to the LANL Waste stored in either the WCS TSDF or the FWF disposal cell. Conditions 9, 10, and 11, respectively, in the 2014 Order would be renumbered as Conditions 10, 11, and 12, respectively, in the new order. WCS would continue to be permitted to possess SNM at the WCS

TSDF that meets the same concentration limits and controls.

The NRC staff finds that the proposed action would result in minor transportation impacts because movement of the LANL Waste from the FWF disposal cell to the WCS TSDF BSA-1 Enclosure would be restricted to the WCS Site and would involve the use of on-site equipment (e.g., the Kalmar and the Goldhofer). In the draft Documented Safety Analysis in its request, WCS also stated that it would not allow other traffic to occur on the route from the FWF disposal cell to the WCS TSDF BSA-1 Enclosure while the MCCs are being moved.

The NRC staff considers impacts to other resource areas to be minimal. Vehicle exhaust and fugitive dust from the equipment used to remove the existing sand cover for the MCCs and to transport the MCCs from the FWF to the WCS TSDF BSA-1 Enclosure would be short term and limited to the WCS Site. As a result, air quality impacts and visual impacts would be minimal. Noise associated with operation of this equipment would also be short term and limited to the site. Given WCS's activities under the proposed action, the NRC staff considers that there would be no impacts to land use, geology and soils, surface and ground water resources, ecological resources, or socioeconomic. Additionally, given the expectation that minor impacts would be limited to the WCS Site, the NRC staff concludes that there would be no disproportionately high and adverse impacts to minority or low-income populations.

The NRC staff recognizes that the DOE would be transporting the LANL Waste from the WCS Site by truck to another location, currently expected to be either LANL or to WIPP. LANL is located in northeastern New Mexico approximately 587 kilometers (365 miles) from WCS, while WIPP is located southeast of Carlsbad, New Mexico, approximately 121 kilometers (75 miles) from WCS. The material would be shipped by DOE from the WCS Site once the material is approved for transport in accordance with U.S. Department of Transportation regulations.

Environmental Impacts of the Alternatives to the Proposed Action

As an alternative to the proposed action, the NRC staff considered denial of the WCS's June 30, 2022, request and not authorizing the requested activities. Under that alternative, WCS would continue to store the LANL Waste in the FWF disposal cell and not move it to the WCS TSDF BSA-1 Enclosure. WCS

would continue to perform monitoring of the waste in its current storage location in the FWF disposal cell and to perform other aspects of its radiation protection program to keep potential radiological doses to workers and the public ALARA.

Under this alternative, the activities identified in WCS's June 30, 2022, request that are needed to prepare the LANL Waste for shipment by DOE off the WCS Site would not occur. The NRC staff considers it reasonable to expect that DOE and WCS would seek an alternate approach to prepare the LANL Waste for shipment off the WCS Site and to request NRC approval of that approach. Thus, the environmental impacts of the no-action alternative would be very similar to those of the proposed action.

Agencies and Persons Consulted

On March 20, 2023, the NRC staff provided a copy of the draft EA to the TCEQ, for its review and comment. The TCEQ provided its comments on April 12, 2023. The NRC staff updated the EA in response to TCEQ's comments, as appropriate.

The proposed action does not involve the development or disturbance of additional land, as the WCS TSDF BSA-1 Enclosure is within an existing structure. Hence, the NRC has determined that the proposed action will not affect listed endangered or threatened species or their critical habitat. Therefore, no further consultation is required under Section 7 of the Endangered Species Act. Likewise, the NRC staff has determined that the proposed action does not have the potential to cause effects on historic properties even if present. The LANL Waste stored in the FWF disposal cell would be moved to temporary storage in the WCS TSDF BSA-1 Enclosure using existing WCS Site roads, and no ground disturbing activities are associated with the proposed action. Therefore, no consultation is required under Section 106 of the National Historic Preservation Act.

III. Finding of No Significant Impact

The NRC has reviewed WCS's June 30, 2022, request for a superseding order. The NRC has found that effluent releases and potential radiological doses to the public are not anticipated to change as a result of this action and that occupational exposures are expected to remain within regulatory limits and ALARA. Based on the EA, the NRC concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the NRC has determined

not to prepare an environmental impact statement for the proposed action.

IV. Availability of Documents

The documents identified in the following table are available to interested persons through ADAMS.

Document description	ADAMS accession No.
NRC letter to WCS, Letter to William Dornsife, WCS, from Thomas Essig, NRC, enclosing the Order to Exempt Waste Control Specialists, LLC, from Requirements of 10 CFR part 70, dated November 21, 2001.	ML030130085.
Issuance of Environmental Assessment and Finding of No Significant Impact for Modification of Exemption from Certain NRC Licensing Requirements for Special Nuclear Material for Waste Control Specialists, LLC., Andrews County, Texas, October 14, 2004.	ML043020614.
Issuance of Environmental Assessment and Final Finding of No Significant Impact for Modification of Exemption from Certain NRC Licensing Requirements for Special Nuclear Material for Waste Control Specialist, LLC., Andrews County, Texas, dated October 7, 2009.	ML092460509.
Issuance of Environmental Assessment and Finding of No. Significant Impact for Modification of Exemption from Certain NRC Licensing Requirements for Special Nuclear Material for Waste Control Specialist, LLC Andrews, dated October 30, 2014".	ML14238A208.
NRC letter to WCS, "Response to Request for Possession Time Extension in the U.S. Nuclear Regulatory Commission Exemption Order Condition 8.B.4 at Waste Control Specialists LLC (CAC No. L00904)," dated September 23, 2016.	ML16097A265.
NRC letter to WCS, "Closeout of NRC Review of WCS Exemption Request dated December 4, 2014 (CAC NO. L00904)," dated September 26, 2017.	ML17234A415.
NRC letter to WCS, "Response to the August 30, 2018, WCS Request to Extend the Possession Time in the NRC Special Nuclear Material Exemption Order Condition 8.B.4 to WCS," dated December 19, 2018.	ML18269A318.
NRC letter to WCS, "Response to the August 24, 2020, WCS Request to Extend the Possession Time of LANL Waste in the Exemption Order Condition 8.B.4 until December 23, 2022," dated December 7, 2020.	ML20252A182.
NRC letter to WCS, "Response to the March 18, 2022, WCS Request to Extend Possession Time of LANL Waste in the Exemption Order Condition 8.B.4 until December 31, 2024," dated June 8, 2022.	ML22094A131.
WCS request, "2022b-06-30-2022 Public WCS Request for Superseding NRC Order for SNM," dated June 30, 2022	ML22200A046.
NRC note to file, "Summary of NRC Clarification Calls with WCS," dated September 14, 2022	ML22257A219.
NRC email to TCEQ attaching Draft EA for review and comment, dated March 20, 2023	ML23129A311.
TCEQ email to NRC providing comments on Draft EA, dated April 12, 2023	ML23129A263.

Dated: May 15, 2023.

For the Nuclear Regulatory Commission.

Robert Sun,

Acting Chief, Environmental Review Materials Branch, Division of Rulemaking, Environmental and Financial Support, Office of Nuclear Material Safety, and Safeguards.

[FR Doc. 2023-10645 Filed 5-17-23; 8:45 am]

BILLING CODE 7590-01-P

POSTAL REGULATORY COMMISSION

[Docket Nos. MC2023-152 and CP2023-156; MC2023-153 and CP2023-157; MC2023-154 and CP2023-158; MC2023-155 and CP2023-159; MC2023-156 and CP2023-160]

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:* May 22, 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
- II. Docketed Proceeding(s)

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.

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).

II. Docketed Proceeding(s)

1. *Docket No(s)*: MC2023–153 and CP2023–156; *Filing Title*: USPS Request to Add Priority Mail Express, Priority Mail, First-Class Package Service & Parcel Select Contract 119 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date*: May 12, 2023; *Filing Authority*: 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative*: Christopher C. Mohr; *Comments Due*: May 22, 2023.

2. *Docket No(s)*: MC2023–153 and CP2023–157; *Filing Title*: USPS Request to Add Priority Mail, First-Class Package Service & Parcel Select Contract 15 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date*: May 12, 2023; *Filing Authority*: 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative*: Christopher C. Mohr; *Comments Due*: May 22, 2023.

3. *Docket No(s)*: MC2023–154 and CP2023–158; *Filing Title*: USPS Request to Add Priority Mail, First-Class Package Service & Parcel Select Contract 16 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date*: May 12, 2023; *Filing Authority*: 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative*: Kenneth R. Moeller; *Comments Due*: May 22, 2023.

4. *Docket No(s)*: MC2023–155 and CP2023–159; *Filing Title*: USPS Request to Add Priority Mail, First-Class Package Service & Parcel Select Contract 17 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date*: May 12, 2023; *Filing Authority*: 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative*: Kenneth R. Moeller; *Comments Due*: May 22, 2023.

5. *Docket No(s)*: MC2023–156 and CP2023–160; *Filing Title*: USPS Request to Add Priority Mail, First-Class Package Service & Parcel Select Contract 18 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date*: May 12, 2023; *Filing Authority*: 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative*: Jennaca D. Upperman; *Comments Due*: May 22, 2023.

This Notice will be published in the **Federal Register**.

Erica A. Barker,
Secretary.

[FR Doc. 2023–10626 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL SERVICE**Product Change—Priority Mail, First-Class Package Service & 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:* May 18, 2023.

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 May 12, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 17 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–155, CP2023–159.

Sean Robinson,

Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10586 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE**Product Change—Priority Mail, First-Class Package Service & 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:* May 18, 2023.

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 May 12, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 15 to Competitive Product List*. Documents are available at

www.prc.gov, Docket Nos. MC2023–153, CP2023–157.

Sean Robinson,

Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10584 Filed 5–17–23; 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:* May 18, 2023.

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 May 12, 2023, 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 119 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–152, CP2023–156.

Sean Robinson,

Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10590 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE**Product Change—Priority Mail Express and 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:* May 18, 2023.

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 May 9, 2023, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Express & Priority Mail Contract 137 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–147, CP2023–150.

Sean Robinson,
Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10588 Filed 5–17–23; 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:* May 18, 2023.

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 May 10, 2023, 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 118 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–149, CP2023–152.

Sean Robinson,
Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10589 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail, First-Class Package Service & 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:* May 18, 2023.

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 May 12, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 18 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–156, CP2023–160.

Sean Robinson,
Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10587 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail, First-Class Package Service & 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:* May 18, 2023.

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 May 10, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 13 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–150, CP2023–153.

Sean Robinson,
Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10582 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail, First-Class Package Service & 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:* May 18, 2023.

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 May 10, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 14 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–151, CP2023–154.

Sean Robinson,
Attorney, Corporate and Postal Business Law.
[FR Doc. 2023–10583 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail, First-Class Package Service & 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:* May 18, 2023.

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 May 12, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 16 to Competitive Product List*. Documents are available at

www.prc.gov, Docket Nos. MC2023–154, CP2023–158.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2023–10585 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail, First-Class Package Service & 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: May 18, 2023.

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 May 8, 2023, it filed with the Postal Regulatory Commission a *Request of the United States Postal Service to Add Priority Mail, First-Class Package Service & Parcel Select Contract 12 to Competitive Product List*. Documents are available at www.prc.gov, Docket Nos. MC2023–146, CP2023–149.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2023–10581 Filed 5–17–23; 8:45 am]

BILLING CODE 7710–12–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–97504; File No. SR–NYSEARCA–2023–36]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the NYSE Arca Equities Fees and Charges

May 15, 2023.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (“Act”),¹ and Rule 19b–4 thereunder,² notice is hereby given that on May 1, 2023, NYSE Arca, Inc. (“NYSE Arca” or the “Exchange”) filed with the

Securities and Exchange Commission (“SEC” or “Commission”) the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the NYSE Arca Equities Fees and Charges (“Fee Schedule”) to amend the fee for orders routed that remove liquidity in away markets in Round Lots and Odd Lots in Tapes A, B and C securities with a per share price below \$1.00, and eliminate an incremental credit associated with the Tier 4 pricing tier under Adding Tiers. The Exchange proposes to implement the fee changes effective May 1, 2023. The proposed rule change is available on the Exchange's website at www.nyse.com, at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the self-regulatory organization included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Fee Schedule to amend the fee for orders routed that remove liquidity in away markets in Round Lots and Odd Lots in Tapes A, B and C securities with a per share price below \$1.00 (“Sub-Dollar Securities”), and eliminate an incremental credit associated with the Tier 4 pricing tier under Adding Tiers. The Exchange proposes to implement the fee changes effective May 1, 2023.

Background

The Exchange operates in a highly competitive market. The Commission has repeatedly expressed its preference for competition over regulatory

intervention in determining prices, products, and services in the securities markets. In Regulation NMS, the Commission highlighted the importance of market forces in determining prices and SRO revenues and, also, recognized that current regulation of the market system “has been remarkably successful in promoting market competition in its broader forms that are most important to investors and listed companies.”³

While Regulation NMS has enhanced competition, it has also fostered a “fragmented” market structure where trading in a single stock can occur across multiple trading centers. When multiple trading centers compete for order flow in the same stock, the Commission has recognized that “such competition can lead to the fragmentation of order flow in that stock.”⁴ Indeed, equity trading is currently dispersed across 16 exchanges,⁵ numerous alternative trading systems,⁶ and broker-dealer internalizers and wholesalers, all competing for order flow. Based on publicly available information, no single exchange currently has more than 17% market share.⁷ Therefore, no exchange possesses significant pricing power in the execution of equity order flow. More specifically, the Exchange currently has less than 10% market share of executed volume of equities trading.⁸

The Exchange believes that the ever-shifting market share among the exchanges from month to month demonstrates that market participants can move order flow, or discontinue or reduce use of certain categories of products. While it is not possible to know a firm's reason for shifting order flow, the Exchange believes that one such reason is because of fee changes at any of the registered exchanges or non-exchange venues to which a firm routes order flow. ETP Holders can choose from any one of the 16 currently operating registered exchanges to route such order flow. Accordingly,

³ See Securities Exchange Act Release No. 51808 (June 9, 2005), 70 FR 37496, 37499 (June 29, 2005) (File No. S7–10–04) (Final Rule) (“Regulation NMS”).

⁴ See Securities Exchange Act Release No. 61358, 75 FR 3594, 3597 (January 21, 2010) (File No. S7–02–10) (Concept Release on Equity Market Structure).

⁵ See Cboe U.S. Equities Market Volume Summary, available at https://markets.cboe.com/us/equities/market_share/.

⁶ See FINRA ATS Transparency Data, available at <https://otctransparency.finra.org/otctransparency/AtsIssueData>. A list of alternative trading systems registered with the Commission is available at <https://www.sec.gov/foia/docs/atlist.htm>.

⁷ See Cboe Global Markets U.S. Equities Market Volume Summary, available at http://markets.cboe.com/us/equities/market_share/.

⁸ See id.

¹ 15 U.S.C. 78s(b)(1).

² 17 CFR 240.19b–4.

competitive forces constrain exchange transaction fees that relate to orders that would provide and take liquidity on an exchange or that are routed to another venue for execution.

Proposed Rule Change

Routing Fee

The Exchange currently charges a standard fee of 0.3% of Dollar Value for orders routed that remove liquidity in away markets in Sub-Dollar Securities across all Tapes.⁹ The Exchange now proposes to increase the fee from 0.3% to 0.35% of Dollar Value for orders routed that remove liquidity in away markets in Sub-Dollar Securities across all Tapes. The purpose of the proposed rule change is for business and competitive reasons. U.S. equity market volumes have been remarkably high in Sub-Dollar Securities since the beginning of 2023, driven in part by retail traders, leading to increased off-exchange (or Trade Reporting Facility (TRF)) trading volumes.¹⁰ Without having a view of ETP Holders' activity on other exchanges and off-exchange venues, the Exchange has no way of knowing whether this modest increase would result in any ETP Holder altering its trading activity in Sub-Dollar Securities. The submission of orders in Sub-Dollar Securities to the Exchange is optional for ETP Holders in that they could choose whether to submit such orders to the Exchange and, if they do, the extent of its activity in this regard.

Eliminate Unused Credit

Currently, under the Adding Tiers table in Section VII. Tier Rates—Round Lots and Odd Lots (Per Share Price \$1.00 or Above), the Exchange provides multiple tiers and associated credits for Adding liquidity on the Exchange. Specifically, under Tier 4, if an ETP Holder has Adding ADV that is equal to at least 0.20% of CADV then that ETP Holder receives a credit of \$0.0025 per share for Adding in Tape A securities, \$0.0022 per share for Adding in Tape B securities and \$0.0025 per share for Adding in Tape C securities. Additionally, ETP Holders that qualify for Tier 4 and have Adding ADV that is equal to 0.05% of CADV above May 2019 receive an incremental credit of

\$0.0002 per share for Tape A and Tape C Adding. This incremental credit is currently denoted on the Fee Schedule under footnote ** and is appended to the credits applicable under Tier 4.

The Exchange proposes to eliminate the incremental credit of \$0.0002 per share for Tape A and Tape C Adding and remove the credit from the Fee Schedule because the pricing incentive has been underutilized by ETP Holders. The Exchange has observed that not a single ETP Holder has qualified for the incremental credit in the last six months. Since the incremental credit has not been effective in accomplishing its intended purpose, which is to incent ETP Holders to increase their liquidity adding activity on the Exchange, the Exchange has determined to eliminate the incremental credit and remove it from the Fee Schedule.

The proposed changes are not otherwise intended to address any other issues, and the Exchange is not aware of any significant problems that market participants would have in complying with the proposed changes.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with section 6(b) of the Act,¹¹ in general, and furthers the objectives of sections 6(b)(4) and (5) of the Act,¹² in particular, because it provides for the equitable allocation of reasonable dues, fees, and other charges among its members, issuers and other persons using its facilities and does not unfairly discriminate between customers, issuers, brokers or dealers.

As discussed above, the Exchange operates in a highly fragmented and competitive market. The Commission has repeatedly expressed its preference for competition over regulatory intervention in determining prices, products, and services in the securities markets. Specifically, in Regulation NMS, the Commission highlighted the importance of market forces in determining prices and SRO revenues and, also, recognized that current regulation of the market system “has been remarkably successful in promoting market competition in its broader forms that are most important to investors and listed companies.”¹³

The Exchange believes that the ever-shifting market share among the exchanges from month to month demonstrates that market participants can shift order flow, or discontinue to reduce use of certain categories of

products, in response to fee changes. Accordingly, competitive forces reasonably constrain exchange transaction rates that relate to orders that would add or remove liquidity on an exchange or that are routed away from an exchange. Stated otherwise, changes to exchange transaction fees and credits can have a direct effect on the ability of an exchange to compete for order flow.

Routing Fee

The Exchange believes that the proposed change to increase the standard fee for routing orders in Sub-Dollar Securities away from the Exchange is reasonable, equitable and consistent with the Act because it represents a modest increase from the current standard fee (change from 0.3% to 0.35% of Dollar Value). The Exchange further believes that the proposal to increase the standard fee for routing orders in Sub-Dollar Securities away from the Exchange is equitably allocated and not unfairly discriminatory because it would apply to all ETP Holders in an equivalent manner.

The Exchange believes that the proposed rule change is equitable and not unfairly discriminatory because ETP Holders will continue to have the option to elect to route their orders in the same manner as they do today and will be automatically and uniformly assessed the applicable standard rates. Further, if ETP Holders do not favor the Exchange's pricing for routed orders, they can send their routable orders directly to other markets instead of utilizing routing functionality provided by the Exchange. Routing through the Exchange is optional, and the Exchange operates in a competitive environment where market participants can readily direct order flow to competing venues or providers of routing services if they believe alternatives offer them better value. The proposal is not unfairly discriminatory because it neither targets nor will it have a disparate impact on any particular category of market participant.

Finally, the submission of orders in Sub-Dollar Securities to the Exchange is optional for ETP Holders in that they could choose whether to submit such orders to the Exchange and, if they do, the extent of its activity in this regard.

Eliminate Unused Credit

The Exchange believes that the proposed rule change to eliminate the incremental credit associated with the Tier 4 pricing tier under Adding Tiers is reasonable because the pricing incentive that is the subject of this proposed rule change has been

⁹Footnote (a) under the Standard Rates—Routing table provides that the fee applies to orders of listed and Nasdaq securities routed away and executed by another market center or participant. See Fee Schedule, available at https://www.nyse.com/publicdocs/nyse/markets/nyse-arca/NYSE_Arca_Marketplace_Fees.pdf.

¹⁰In the first quarter of 2023, the TRF represented about 60.2% market share in Sub-Dollar Securities. See Choe Insights, available at <https://www.choe.com/insights/posts/how-subdollar-securities-are-trading-now/>.

¹¹ 15 U.S.C. 78f(b).

¹² 15 U.S.C. 78f(b)(4) and (5).

¹³ See Regulation NMS, 70 FR at 37499.

underutilized and has not incentivized ETP Holders to bring liquidity and increase trading on the Exchange as anticipated. No ETP Holder has availed itself of the incremental credit in the last six months. The Exchange also does not anticipate any ETP Holder in the near future will qualify for the pricing incentive that is the subject of this proposed rule change. The Exchange believes it is reasonable to eliminate requirements and credits, and even entire pricing tiers, when such incentives become underutilized. The Exchange believes eliminating underutilized incentive programs would also simplify the Fee Schedule. The Exchange further believes that removing reference to the incremental credit that the Exchange proposes to eliminate from the Fee Schedule would also add clarity to the Fee Schedule. The Exchange believes that eliminating requirements and credits, and even entire pricing tiers, from the Fee Schedule when such incentives become ineffective is equitable and not unfairly discriminatory because the requirements, and credits, and even entire pricing tiers, would be eliminated in their entirety and would no longer be available to any ETP Holder. All ETP Holders would continue to be subject to the same fee structure, and access to the Exchange's market would continue to be offered on fair and non-discriminatory terms. The Exchange also believes that the proposed change would protect investors and the public interest because the deletion of underutilized pricing incentives would make the Fee Schedule more accessible and transparent and facilitate market participants' understanding of the fees charged for services currently offered by the Exchange.

For the foregoing reasons, the Exchange believes that the proposal is consistent with the Act.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with section 6(b)(8) of the Act,¹⁴ the Exchange believes that the proposed rule change would not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange believes that the proposed change to modestly increase a routing fee would continue to encourage ETP Holders to maintain their order flow on the Exchange, thereby promoting market depth, price discovery and transparency. As a result, the Exchange believes that the proposed changes further the Commission's goal in

adopting Regulation NMS of fostering integrated competition among orders, which promotes "more efficient pricing of individual stocks for all types of orders, large and small."¹⁵

Intramarket Competition. The proposed changes are designed to respond to the current competitive environment. The Exchange believes that the proposed change to modestly increase a routing fee would continue to incentivize market participants to direct order flow to the Exchange. Greater liquidity benefits all market participants on the Exchange by providing more trading opportunities and encourages ETP Holders to send orders, thereby contributing to robust levels of liquidity, which benefits all market participants on the Exchange. The proposed fee would be applicable to all similarly-situated market participants, and, as such, the proposed change would not impose a disparate burden on competition among market participants on the Exchange. The Exchange's proposal to eliminate an incremental credit will not place any undue burden on intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act given that not a single ETP Holder has qualified for the credit proposed for deletion for the last six months. To the extent the proposed rule change places a burden on competition, any such burden would be outweighed by the fact that the pricing incentive proposed for deletion has not served its intended purpose of incentivizing ETP Holders to more broadly participate on the Exchange.

As such, the Exchange believes the proposed amendment to its Fee Schedule would not impose any burden on intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act.

Intermarket Competition. The Exchange operates in a highly competitive market in which market participants can readily choose to send their orders to other exchange and off-exchange venues if they deem fee levels at those other venues to be more favorable. As noted above, the Exchange's market share of intraday trading (*i.e.*, excluding auctions) is currently less than 10%. In such an environment, the Exchange must continually adjust its fees and rebates to remain competitive with other exchanges and with off-exchange venues. Because competitors are free to modify their own fees and credits in response, and because market participants may readily adjust their order routing practices, the Exchange

does not believe its proposed fee change can impose any burden on intermarket competition.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective upon filing pursuant to section 19(b)(3)(A)¹⁶ of the Act and paragraph (f) thereunder. At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's internet comment form (<http://www.sec.gov/rules/sro.shtml>); or
- Send an email to rule-comments@sec.gov. Please include File Number SR-NYSEARCA-2023-36 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549-1090.

All submissions should refer to File Number SR-NYSEARCA-2023-36. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's internet website (<http://www.sec.gov/rules/sro.shtml>). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the

¹⁴ 15 U.S.C. 78f(b)(8).

¹⁵ See Regulation NMS, 70 FR at 37498-99.

¹⁶ 15 U.S.C. 78s(b)(3)(A).

proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street NE, Washington, DC 20549 on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal offices of the Exchange. Do not include personal identifiable information in submissions; you should submit only information that you wish to make available publicly. We may redact in part or withhold entirely from publication submitted material that is obscene or subject to copyright protection. All submissions should refer to File Number SR-NYSEARCA-2023-36, and should be submitted on or before June 8, 2023.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.¹⁷

Sherry R. Haywood,
Assistant Secretary.

[FR Doc. 2023-10685 Filed 5-17-23; 8:45 am]

BILLING CODE 8011-01-P

SOCIAL SECURITY ADMINISTRATION

[Docket No: SSA-2023-0016]

Agency Information Collection Activities: 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 one new information collection for OMB approval.

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-2023-0016].

(SSA), Social Security Administration, OLCA, Attn: Reports Clearance Director, 3100 West High Rise, 6401 Security Blvd., Baltimore, MD 21235, Fax: 833-410-1631, 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-2023-0016].

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 June 20, 2023. Individuals can obtain copies of this OMB clearance package by writing to OR.Reports.Clearance@ssa.gov.

Upload Documents (eSubmit)—20 CFR 404.704; 404.1512, 416.912, and 422.505—0960-NEW

Background

From March 17, 2020, through April 7, 2022, because of the Coronavirus (COVID-19) public health emergency, SSA encouraged the public to use our online and automated telephone services while we offered limited in-person services in field offices. While we were able to complete forms with the public through our personal interview process via telephone or video conference, we still needed to request the submission of evidence and some paper forms for which we have no other process. The need to submit these forms to SSA via mail poses a significant burden on the members of the public doing business with us. In addition, the increased volume of documents sent to our field offices presented an enormous challenge to SSA, as we had limited staff on site to process the mail at that time. This limited the time the field office staff had to review and process those submissions or work directly with the public. To lessen the burden on front-line employees and managers, allow staff more time to work with the public and process the information we receive, and to modernize form submission and document intake, we are creating a new service called Upload Documents (eSubmit).

Upload Documents (eSubmit)

SSA is introducing Upload Documents (eSubmit), a new way individuals can submit evidence and

forms to SSA online. In the digital age, individuals expect to complete transactions online, including submission of documents and forms to government agencies. The agency already offers several self-service specific options for individuals to submit forms and other documents online, including the Electronic Protective Filing Tool, ePFT (OMB No. 0960-0826), internet Social Security Benefits Application, iClaim (OMB No. 0960-0618), and iAppeals (OMB No. 0960-0269 & 0960-0622).

Upload Documents (eSubmit) is a secure upload portal which respondents will use to submit documents and forms to SSA. To ensure the success of Upload Documents (eSubmit), we will roll out the new application in several phases. The first phase will allow respondents to provide select documents (evidence that does not need to be certified or evidence which the agency does not require to be an original, also known collectively as "non original documentation," and first-party forms that do not require a signature) to SSA electronically. Individuals must provide this information themselves since they will have to authenticate with their own information through one of several authentication methods (*i.e.*, [Login.gov](https://www.login.gov), ID.me, or SSA's Public Credentialing and Authentication Process).

During this initial release for Upload Documents (eSubmit), we will contact the respondent, via telephone or face-to-face interview with SSA, for a business matter (*e.g.*, filing a claim, performing a redetermination, or updating their personal information). During the interaction, the SSA technician will inform the individual verbally that SSA requires additional information to support their request and will offer the opportunity to provide the information electronically via the Upload Documents (eSubmit) application. After the respondent grants consent to SSA, we will generate a one-time email containing a link to Upload Documents (eSubmit) with instructions on how to access Upload Documents (eSubmit). The system will only make the electronic submission process available within 30 days from the date of the email. Concurrently, the technician will print a paper notice containing more details about the request, including any applicable due process deadline for submission, and will send it through postal mail to the respondent. Once the respondent authenticates and arrives at the Upload Documents (eSubmit) dashboard, the system will present the respondent with information regarding the items SSA requested for submission (examples of the documentation SSA

¹⁷ 17 CFR 200.30-3(a)(12).

may request include forms or non-standardized evidence to support the request [e.g., pay stubs, bank statements, pension award letters, tax documents, child support payment history, etc.]). From this screen, the individual will be able to upload the corresponding files from an electronic device. Once they finish uploading the documents, the respondents must select the Submit button to complete the action and the system will present them with an indicator of success or failure. The system will notify the technician through the Technician Experience Dashboard (TED) when the document is available for review and consideration.

The second release of Upload Documents (eSubmit) will include an electronic signature functionality that

will allow respondents to submit some forms requiring signature.

Respondents are first-party individuals who choose to use the internet to conduct business with us. To ensure Upload Documents (eSubmit) will collect respondents' legally enforceable electronic signature, SSA developed an electronic signing process in consideration of the five requirements for a legally valid and binding electronic signature established by the General Services Administration, Federal Chief Information Officers Council guidance in *Use of Electronic Signatures in Federal Organization Transactions*: (1) Identification and Authentication of Signer; (2) Electronic Form of Signature; (3) Intent to Sign; (4) Signature Attached to or Associated

with the Signed Electronic Record; and (5) Preservation of the Integrity of the Record. Our new Upload Documents (eSubmit) platform will incorporate these requirements for the second release, thereby allowing us to accept electronically signed forms and documents through the new Upload Documents (eSubmit) portal. To ensure our system is prepared to accept forms electronically signed in this manner, we will complete periodic future releases after the second release to allow Upload Documents (eSubmit) to accept more agency forms in the future.

Respondents are first-party individuals who choose to use the internet to conduct business with us.

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 for teleservice center (minutes)**	Total annual opportunity cost (dollars)**
Internet version Release #1	904,569	1	7	105,533	* \$28.01	** 19	*** \$10,979,357
Internet Version Release #2	960,196	1	7	112,023	* 28.01	** 19	*** 11,649,539
Totals	1,864,765			217,556	* 28.01	** 19	*** 22,628,896

* We based these figures on average U.S. worker's hourly wages (based on BLS.gov data, https://www.bls.gov/oes/current/oes_nat.htm).

** We based this figure on average FY 2023 wait times for teleservice centers (approximately 19 minutes per respondent), 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: May 15, 2023.

Naomi Sipple,

Reports Clearance Officer, Social Security Administration.

[FR Doc. 2023-10633 Filed 5-17-23; 8:45 am]

BILLING CODE 4191-02-P

Contact: Alexander Dusenberry, (202) 245-0319.

Jeffrey Herzig,
Clearance Clerk.

[FR Doc. 2023-10568 Filed 5-17-23; 8:45 am]

BILLING CODE 4915-01-P

Contact: Alexander Dusenberry, (202) 245-0319.

Brendetta Jones,
Clearance Clerk.

[FR Doc. 2023-10642 Filed 5-17-23; 8:45 am]

BILLING CODE 4915-01-P

SURFACE TRANSPORTATION BOARD

Release of Waybill Data

The Surface Transportation Board has received a request from Jin Yang of Northwestern University (WB23-30—5/11/23) for permission to use data from the Board's annual 1984-2021 unmasked Carload Waybill Samples. A copy of this request may be obtained from the Board's website under docket no. WB23-30.

The waybill sample contains confidential railroad and shipper data; therefore, if any parties object to these requests, they should file their objections with the Director of the Board's Office of Economics within 14 calendar days of the date of this notice. The rules for release of waybill data are codified at 49 CFR 1244.9.

SURFACE TRANSPORTATION BOARD

Release of Waybill Data

The Surface Transportation Board has received a request from William G. Secor (WB23-23—3/27/23) for permission to use data from the Board's annual 2008-2020 unmasked Carload Waybill Samples. A copy of this request may be obtained from the Board's website under Docket No. WB23-23.

The waybill sample contains confidential railroad and shipper data; therefore, if any parties object to these requests, they should file their objections with the Director of the Board's Office of Economics within 14 calendar days of the date of this notice. The rules for release of waybill data are codified at 49 CFR 1244.9.

SURFACE TRANSPORTATION BOARD

[Docket No. FD 36486 (Sub-No. 5)]

Grainbelt Corporation—Trackage Rights Exemption—BNSF Railway Company

By petition filed on February 21, 2023, Grainbelt Corporation (GNBC) requests that the Board partially revoke the trackage rights exemption granted to it under 49 CFR 1180.2(d)(7) in Docket No. FD 36486 (Sub-No. 4), as necessary to permit that trackage rights arrangement to expire on March 31, 2024. GNBC filed its verified notice of exemption on February 21, 2023, and simultaneously filed its petition for partial revocation. Notice of the exemption was served and published in the **Federal Register** (88 FR 14,664) on

March 9, 2023, and the exemption became effective on March 23, 2023.

As explained by GNBC in its verified notice of exemption in Docket No. FD 36486 (Sub-No. 4), GNBC and BNSF Railway Company (BNSF) have entered into an amendment to extend the term of the previously amended, local trackage rights on trackage owned by BNSF between approximately milepost 668.73 in Long, Okla., and approximately milepost 723.30 in Quanah, Tex. (the Line), allowing GNBC to (1) use the Line to access the Plains Cotton Cooperative Association (PCCA) facility near BNSF Chickasha Subdivision milepost 688.6 at Altus, Okla., and (2) operate additional trains on the Line to accommodate the movement of trains transporting BNSF customers' railcars (loaded or empty) located along the Line to unit train facilities on the Line (collectively, the PCCA Trackage Rights). (GNBC Verified Notice of Exemption 3–5, *Grainbelt Corp.—Trackage Rts. Exemption—BNSF Ry.*, FD 36486 (Sub-No. 4).)

GNBC explains that the trackage rights covered by the verified notice in Docket No. FD 36486 (Sub-No. 4) are local rather than overhead rights and therefore they do not qualify for the Board's class exemption for temporary trackage rights under 49 CFR 1180.2(d)(8). (GNBC Pet. 3–4.) GNBC therefore filed its verified notice of exemption under the Board's class exemption procedures at 49 CFR 1180.2(d)(7) and a petition for partial revocation of the exemption as necessary to permit the PCCA Trackage Rights to expire on March 31, 2024, pursuant to the parties' agreement. (GNBC Pet 3.) GNBC argues that the requested relief will promote the rail transportation policy and is limited in scope. (*Id.* at 4–5.) GNBC also asserts that the Board has routinely granted similar petitions to allow trackage rights to expire on a negotiated date. (*Id.* at 4.)

Discussion and Conclusions

Although GNBC and BNSF have expressly agreed on the duration of the proposed trackage rights, trackage rights approved under the class exemption at 49 CFR 1180.2(d)(7) typically remain effective indefinitely, regardless of any contractual provisions. At times, however, the Board has partially revoked a trackage rights exemption to allow those rights to expire after a limited time rather than lasting in perpetuity. *See, e.g., Grainbelt Corp.—Trackage Rts. Exemption—BNSF Ry.*, FD 36486 (Sub-No. 3) (STB served Apr. 6, 2022) (granting a petition to partially revoke a trackage rights exemption involving the Line at issue in this case);

BNSF Ry.—Trackage Rts. Exemption—Union Pac. R.R., FD 36377 (Sub-No. 7) (STB served Mar. 2, 2023); *New Orleans Pub. Belt R.R.—Trackage Rts. Exemption—Ill. Cent. R.R.*, FD 36198 (Sub-No. 1) (STB served June 20, 2018).

Granting partial revocation in these circumstances to permit the trackage rights to expire would eliminate the need for GNBC to file a second pleading seeking discontinuance when the agreement expires, thereby promoting the rail transportation policy at 49 U.S.C. 10101(2), (7), and (15). Moreover, partially revoking the exemption to limit the term of the trackage rights is consistent with the limited scope of the transaction previously exempted.¹ Therefore, the Board will grant the petition and permit the trackage rights exempted in Docket No. FD 36486 (Sub-No. 4) to expire on March 31, 2024.

To provide the statutorily mandated protection to any employee adversely affected by the discontinuance of trackage rights, the Board will impose the employee protective conditions set forth in *Oregon Short Line Railroad—Abandonment Portion Goshen Branch Between Firth & Ammon, in Bingham & Bonneville Counties, Idaho*, 360 I.C.C. 91 (1979).

This action is categorically excluded from environmental review under 49 CFR 1105.6(c).

It is ordered:

1. The petition for partial revocation of the trackage rights class exemption is granted.
2. As discussed above, the trackage rights in Docket No. FD 36486 (Sub-No. 4) are permitted to expire on March 31, 2024, subject to the employee protective conditions set forth in *Oregon Short Line Railroad*, 360 I.C.C. 91.
3. Notice of this decision will be published in the **Federal Register**.
4. This decision is effective on June 14, 2023. Petitions to stay must be filed by May 25, 2023. Petitions for reconsideration must be filed by June 5, 2023.

Decided: May 15, 2023.

By the Board, Board Members Fuchs, Hedlund, Oberman, Primus, and Schultz.

Eden Besera,

Clearance Clerk.

[FR Doc. 2023–10627 Filed 5–17–23; 8:45 am]

BILLING CODE 4915–01–P

¹ Because the proposed transaction is of limited scope, the Board need not make a market power finding. *See* 49 U.S.C. 10502(a).

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Notice of Availability of Draft Air Tour Management Plans and Draft Environmental Assessments (EA) and Public Meetings

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice.

SUMMARY: The FAA, in cooperation with the National Park Service (NPS), has initiated development of ATMPs for Haleakalā National Park, Hawai'i Volcanoes National Park, Mount Rushmore National Memorial, and Badlands National Park (collectively referred to as the Parks) pursuant to the National Parks Air Tour Management Act of 2000 and its implementing regulations. This notice announces the public availability of the draft ATMPs and draft EAs for comment and the dates of the public meetings for each of the Parks. The purpose of the public meetings is to review the draft ATMPs with the public. The draft ATMPs provide acceptable and effective measures to mitigate or prevent the significant adverse impacts, if any, of commercial air tour operations upon the Parks' natural and cultural resources and visitor experiences, as well as on tribal lands. In accordance with section 106 of the National Historic Preservation Act, the FAA and the NPS are also seeking public comment on the potential of the draft ATMPs to cause adverse effects to historic properties.

DATES:

Comment Period Dates

For Haleakalā and Hawai'i Volcanoes National Parks, comments must be received on or before June 16, 2023, by 8:00 p.m. HST. For Mount Rushmore National Memorial and Badlands National Park, comments must be received on or before June 16, 2023, by 11:59 MDT.

Comments will be received on the NPS Planning, Environment and Public Comment System (PEPC) website. Each park's website link is below:

- Haleakalā National Park—<https://parkplanning.nps.gov/HaleakalaATMP>
- Hawai'i Volcanoes National Park—<https://parkplanning.nps.gov/HawaiiVolcanoesATMP>
- Mount Rushmore National Memorial—<https://parkplanning.nps.gov/MountRushmoreATMP>

- Badlands National Park—<https://parkplanning.nps.gov/BadlandsATMP>

Before including your address, phone number, email address, or other personal identifying information in your comment, be advised that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can ask in your comment to withhold from public review your personal identifying information, we cannot guarantee that we will be able to do so.

Public Meeting Dates

The meetings will be held virtually at the dates and times listed below. Questions will be accepted during the public meeting for each Park through a separate form. The link for the question form is provided below for each meeting.

- Badlands National Park
 - Wednesday, May 24, 2023 (6:00 p.m.–7:30 p.m. MDT)
 - Join meeting: <https://faavideo.zoomgov.com/j/1600068134>
 - Passcode: 246810
 - To join using the “Zoom Cloud Meetings” app, please use the meeting ID and passcode below:
 - Meeting ID: 160 006 8134
 - Passcode: 246810
 - To join using phone audio only, please use:
 - Call 1–888–924–3239
 - Meeting ID: 160 006 8134
 - Passcode: 246810
 - Submit questions for the meeting: <https://forms.gle/6msA7mFayKq13ch49>
- Haleakalā National Park
 - Thursday, May 25, 2023 (6:00 p.m.–7:30 p.m. HST)
 - Join meeting: <https://faavideo.zoomgov.com/j/1614722433>
 - Passcode: 246810
 - To join using the “Zoom Cloud Meetings” app, please use the meeting ID and passcode below:
 - Meeting ID: 161 472 2433
 - Passcode: 246810
 - To join using phone audio only, please use:
 - Call 1–888–924–3239
 - Meeting ID: 161 472 2433
 - Passcode: 246810
 - Submit questions for the meeting: <https://forms.gle/nCCQcSniKrBTz2RXXA>
- Mount Rushmore National Memorial
 - Thursday, June 1, 2023 (6:00 p.m.–7:30 p.m. MDT)
 - Join meeting: <https://faavideo.zoomgov.com/j/1615600109>

faavideo.zoomgov.com/j/1615600109

- Passcode: 246810
- To join using the “Zoom Cloud Meetings” app, please use the meeting ID and passcode below:
 - Meeting ID: 161 560 0109
 - Passcode: 246810
- To join using phone audio only, please use:
 - Call 1–888–924–3239
 - Meeting ID: 161 560 0109
 - Passcode: 246810
- Submit questions for the meeting: <https://forms.gle/Jm5cT4DHhfta8fnP9>
- Hawai’i Volcanoes National Park
 - Wednesday, June 7, 2023 (6:00 p.m.–7:30 p.m. HST)
 - Join meeting: <https://faavideo.zoomgov.com/j/1615197156>
 - Passcode: 246810
 - To join using the “Zoom Cloud Meetings” app, please use the meeting ID and passcode below:
 - Meeting ID: 161 519 7156
 - Passcode: 246810
 - To join using phone audio only, please use:
 - Call 1–888–924–3239
 - Meeting ID: 161 519 7156
 - Passcode: 246810
 - Submit questions for the meeting: <https://forms.gle/NK67Ue1cGg25tWoZ6>

ADDRESSES: The meetings will be held virtually. Members of the public who wish to observe the virtual meetings can access the live meeting through the links provided in this notice on the day of the event. The meeting links will also be available at *Air Tour Management Plan | Federal Aviation Administration (faa.gov)* and on the NPS PEPC websites for each Park.

Contact: Any request for reasonable accommodation related to providing public comments on the draft ATMPs or draft EAs should be sent to the person listed on the Parks’ PEPC sites. The U.S. Department of Transportation and U.S. Department of the Interior are committed to providing equal access to the meetings for all participants. If you need alternative formats or services because of a disability, such as sign language, interpretation, or other ancillary aids, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT: Sandra Fox, (202) 267–0928, Sandra.Y.Fox@faa.gov.

SUPPLEMENTARY INFORMATION: The FAA is issuing this notice pursuant to the National Parks Air Tour Management Act of 2000 (Pub. L. 106–181) and its

implementing regulations contained in Title 14, Code of Federal Regulations, part 136, subpart B, National Parks Air Tour Management. The objectives of the ATMPs are to develop acceptable and effective measures to mitigate or prevent the significant adverse impacts, if any, of commercial air tour operations upon the natural resources, cultural resources, and visitor experiences of the Parks as well as on tribal lands. The FAA and the NPS are inviting comment from the public, Federal and state agencies, tribes, Native Hawaiian Organizations, and other interested parties on the draft ATMPs and draft EAs for Haleakalā National Park, Hawai’i Volcanoes National Park, Mount Rushmore National Memorial, and Badlands National Park.

The FAA and the NPS have determined that each ATMP constitutes a Federal undertaking subject to compliance with Section 106 of the National Historic Preservation Act and its implementing regulations (36 CFR part 800). The FAA and the NPS have consulted with tribes, Native Hawaiian Organizations, State and Tribal Historic Preservation Officers, and other interested parties to identify historic properties and assess the potential effects of ATMPs on them.

The meetings will be open to the public. Members of the public who wish to observe the virtual meetings can access the livestream from the links and websites provided in this notice.

The FAA and the NPS request that comments be as specific as possible in response to the draft ATMPs and draft EAs. All written comments become part of the official record. Written comments on the draft ATMPs and draft EAs can be submitted via PEPC or sent to the mailing addresses provided on the Parks’ PEPC sites. Comments will not be accepted by fax, email, or any other way than those specified above.

Issued in Washington, DC, on May 15, 2023.

Sandra Fox,

Environmental Protection Specialist, FAA Office of Environment & Energy.

[FR Doc. 2023–10622 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION**Federal Motor Carrier Safety Administration**

[Docket No. FMCSA–2006–26367]

Motor Carrier Safety Advisory Committee (MCSAC); Notice of Public Meeting

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation.

ACTION: Notice of public meeting.

SUMMARY: FMCSA announces a meeting of MCSAC, which will take place via videoconference.

DATES: The meeting will be held Tuesday and Wednesday, June 6–7, 2023, from 9:30 a.m. to 4:30 p.m., Eastern Time. Requests for accommodations because of a disability must be received by Wednesday, May 31. Requests to register and/or to submit written materials to be reviewed during the meeting must be received no later than Wednesday, May 31.

ADDRESSES: The meeting will be held via videoconference. Those members of the public who would like to participate should go to <https://www.fmcsa.dot.gov/advisory-committees/mcsac/meetings> to access the meeting, task statements, a detailed agenda for the entire meeting, meeting minutes and additional information on MCSAC and its activities.

FOR FURTHER INFORMATION CONTACT: Shannon L. Watson, Senior Advisor to the Associate Administrator for Policy, Federal Motor Carrier Safety Administration, U.S. Department of Transportation, 1200 New Jersey Avenue SE, Washington, DC 20590, (202) 360–2925, mcsac@dot.gov. Any MCSAC-related request or submission should be sent via email to the person listed in this section.

Information may also be submitted by docket through Docket Number FMCSA–2006–26367 using any of the following methods:

- *Federal eRulemaking Portal:* Go to <http://www.regulations.gov>. Follow the online instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* Docket Operations, U.S. Department of Transportation, 1200 New Jersey Avenue SE, Room W12–140, Washington, DC 20590.
- *Hand Delivery:* Docket Operations, U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building, Room W12–140, Washington, DC, between 9 a.m. and 5 p.m., E.T. Monday through Friday, except Federal holidays.

To be sure someone is there to help you, please call (202) 366–9317 or (202) 366–9826 before visiting Docket Operations.

SUPPLEMENTARY INFORMATION:**I. Background***Purpose of the Committee*

MCSAC was established to provide FMCSA with advice and recommendations on motor carrier safety programs and motor carrier safety regulations. MCSAC is composed of up to 25 voting representatives from the motor carrier safety advocacy, safety enforcement, labor, and industry sectors. The diversity of MCSAC ensures the requisite range of views and expertise necessary to discharge its responsibilities. MCSAC operates as a statutory committee under the authority of the U.S. Department of Transportation (DOT), established in accordance with the provisions of the Federal Advisory Committee Act (FACA), as amended (5 U.S.C. app. 2).

Meeting Agenda

The Agenda for the meeting will consist of:

- A briefing by the NHTSA and FMCSA concerning the most recent traffic safety data in general, and the commercial motor vehicle crash (CMV) data.
- A briefing on FMCSA's Large Truck Crash Causal Factors study plan and objectives.
- A briefing on the National Roadway Safety Strategy, including the 2023 update released in February followed by a new task, Task 23–1, relating to the identification of opportunities for FMCSA to collaborate with stakeholders to gain their commitment for additional actions to improve CMV safety.
- A briefing on the DOT's Strategic Plan and FMCSA's current strategic plan, followed by a new task, Task 23–2, regarding FMCSA's efforts to prepare a new strategic plan for FY 2024–FY 2027.

II. Meeting Participation

Advance registration is required. Please register at www.fmcsa.dot.gov/mcsac by the deadline referenced in the **DATES** section. The meeting will be open to the public for its entirety. The U.S. Department of Transportation is committed to providing equal access to this meeting for all participants. If you need alternative formats or services because of a disability, such as sign language, interpretation, or other ancillary aids, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Oral comments from the public will be heard during the public comment

period only at the discretion of the MCSAC chair and designated federal officer. FMCSA asks individuals from the public to limit their comments to one minute on the issues under consideration only. Members of the public may submit written comments to the person listed in the **FOR FURTHER INFORMATION CONTACT** section on the topics to be considered during the meeting by the deadline referenced in the **DATES** section.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2023–10641 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION**Federal Motor Carrier Safety Administration**

[Docket No. FMCSA–2023–0042]

Qualification of Drivers; Exemption Applications; Implantable Cardioverter Defibrillators (ICDs)

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of applications for exemption; request for comments.

SUMMARY: FMCSA announces receipt of an application from one individual for an exemption from the prohibition in the Federal Motor Carrier Safety Regulations (FMCSRs) against operation of a commercial motor vehicle (CMV) by persons with a current clinical diagnosis of myocardial infarction, angina pectoris, coronary insufficiency, thrombosis, or any other cardiovascular disease of a variety known to be accompanied by syncope (transient loss of consciousness), dyspnea (shortness of breath), collapse, or congestive heart failure. If granted, the exemption would enable this individual with an ICD to operate CMVs in interstate commerce.

DATES: Comments must be received on or before June 20, 2023.

ADDRESSES: You may submit comments identified by the Federal Docket Management System Docket No. FMCSA–2023–0042 using any of the following methods:

- *Federal eRulemaking Portal:* Go to www.regulations.gov, insert the docket number (FMCSA–2023–0042) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, and click on the “Comment” button. Follow the online instructions for submitting comments.

- **Mail:** Dockets Operations; U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Washington, DC 20590–0001.

- **Hand Delivery:** West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC, between 9 a.m. and 5 p.m. ET Monday through Friday, except Federal Holidays.

- **Fax:** (202) 493–2251.

To avoid duplication, please use only one of these four methods. See the “Public Participation” portion of the **SUPPLEMENTARY INFORMATION** section for instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: Ms. Christine A. Hydock, Chief, Medical Programs Division, FMCSA, DOT, 1200 New Jersey Avenue SE, Room W64–224, Washington, DC 20590–0001, (202) 366–4001, fmcsamedical@dot.gov. Office hours are from 8:30 a.m. to 5 p.m. ET Monday through Friday, except Federal holidays. If you have questions regarding viewing or submitting material to the docket, contact Dockets Operations, (202) 366–9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Submitting Comments

If you submit a comment, please include the docket number for this notice (Docket No. FMCSA–2023–0042), indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so that FMCSA can contact you if there are questions regarding your submission.

To submit your comment online, go to www.regulations.gov/docket?D=FMCSA-2023-0042. Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, click the “Comment” button, and type your comment into the text box on the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing.

FMCSA will consider all comments and material received during the comment period.

B. Viewing Comments

To view comments go to www.regulations.gov. Insert the docket number (FMCSA–2023–0042) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, and click “Browse Comments.” If you do not have access to the internet, you may view the docket online by visiting Dockets Operations on the ground floor of the DOT West Building, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, between 9 a.m. and 5 p.m. ET Monday through Friday, except Federal holidays. To be sure someone is there to help you, please call (202) 366–9317 or (202) 366–9826 before visiting Dockets Operations.

C. Privacy Act

In accordance with 49 U.S.C. 31315(b)(6), DOT solicits comments from the public on the exemption requests. DOT posts these comments, without edit, including any personal information the commenter provides, to www.regulations.gov. As described in the system of records notice DOT/ALL 14 (Federal Docket Management System), which can be reviewed at <https://www.transportation.gov/individuals/privacy/privacy-act-system-records-notices>, the comments are searchable by the name of the submitter.

II. Background

Under 49 U.S.C. 31136(e) and 31315(b), FMCSA may grant an exemption from the FMCSRs for no longer than a 5-year period if it finds such exemption would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved absent such exemption. The statutes also allow the Agency to renew exemptions at the end of the 5-year period. FMCSA grants medical exemptions from the FMCSRs for a 2-year period to align with the maximum duration of a driver’s medical certification.

The one individual listed in this notice has requested an exemption from § 391.41(b)(4). Accordingly, the Agency will evaluate the qualifications of the applicant to determine whether granting the exemption will achieve the required level of safety mandated by statute.

The physical qualification standard found in § 391.41(b)(4) states that a person is physically qualified to drive a CMV if that person has no current clinical diagnosis of myocardial infarction, angina pectoris, coronary insufficiency, thrombosis, or any other cardiovascular disease of a variety known to be accompanied by syncope,

dyspnea, collapse, or congestive cardiac failure.

In addition to the regulations, FMCSA has published advisory criteria¹ to assist medical examiners in determining whether drivers with certain medical conditions are qualified to operate a CMV in interstate commerce. The advisory criteria states that ICDs are disqualifying due to risk of syncope.

III. Qualifications of Applicants

Nicholas Steffler

Nicholas Steffler is a class B driver’s license holder in North Carolina. An October 10, 2022, letter from Nicholas Steffler’s cardiologist reports that their ICD was prophylactically implanted on June 18, 2018, because of a positive family history of premature sudden death. Nicholas Steffler’s cardiologist also reports no ICD shock history or syncopal episodes and that annual stress tests and other diagnostic imaging remain unchanged from prior evaluations.

IV. Request for Comments

In accordance with 49 U.S.C. 31136(e) and 31315(b), FMCSA requests public comment from all interested persons on the exemption petitions described in this notice. We will consider all comments received before the close of business on the closing date indicated under the **DATES** section of the notice.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2023–10608 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA–2012–0154; FMCSA–2013–0124; FMCSA–2014–0102; FMCSA–2014–0103; FMCSA–2014–0104; FMCSA–2014–0106; FMCSA–2014–0107; FMCSA–2015–0328; FMCSA–2016–0003; FMCSA–2018–0135; FMCSA–2018–0136; FMCSA–2018–0137; FMCSA–2020–0027; FMCSA–2020–0028]

Qualification of Drivers; Exemption Applications; Hearing

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of final disposition.

¹ These criteria may be found in 49 CFR part 391, Appendix A to Part 391—Medical Advisory Criteria, Section D. Cardiovascular: § 391.41(b)(4), paragraph 4, which is available on the internet at <https://www.gpo.gov/jdsys/pkg/CFR-2015-title49-vol5/pdf/CFR-2015-title49-vol5-part391-appA.pdf>.

SUMMARY: FMCSA announces its decision to renew exemptions for 28 individuals from the hearing requirement in the Federal Motor Carrier Safety Regulations (FMCSRs) for interstate commercial motor vehicle (CMV) drivers. The exemptions enable these hard of hearing and deaf individuals to continue to operate CMVs in interstate commerce.

DATES: Each group of renewed exemptions were applicable on the dates stated in the discussions below and will expire on the dates provided below.

FOR FURTHER INFORMATION CONTACT: Ms. Christine A. Hydock, Chief, Medical Programs Division, FMCSA, DOT, 1200 New Jersey Avenue SE, Room W64-224, Washington, DC 20590-0001, (202) 366-4001, fmcsamedical@dot.gov. Office hours are 8:30 a.m. to 5 p.m. ET Monday through Friday, except Federal holidays. If you have questions regarding viewing or submitting material to the docket, contact Dockets Operations, (202) 366-9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Viewing Comments

To view comments go to www.regulations.gov. Insert the docket number (FMCSA-2012-0154, FMCSA-2013-0124, FMCSA-2014-0102, FMCSA-2014-0103, FMCSA-2014-0104, FMCSA-2014-0106, FMCSA-2014-0107, FMCSA-2015-0328, FMCSA-2016-0003, FMCSA-2018-0135, FMCSA-2018-0136, FMCSA-2018-0137, FMCSA-2020-0027, or FMCSA-2020-0028) in the keyword box and click "Search." Next, sort the results by "Posted (Newer-Older)," choose the first notice listed, and click "Browse Comments." If you do not have access to the internet, you may view the docket online by visiting Dockets Operations in Room W12-140 on the ground floor of the DOT West Building, 1200 New Jersey Avenue SE, Washington, DC 20590-0001, between 9 a.m. and 5 p.m. ET Monday through Friday, except Federal holidays. To be sure someone is there to help you, please call (202) 366-9317 or (202) 366-9826 before visiting Dockets Operations.

B. Privacy Act

In accordance with 49 U.S.C. 31315(b)(6), DOT solicits comments from the public on the exemption requests. DOT posts these comments, without edit, including any personal information the commenter provides, to www.regulations.gov. As described in the system of records notice DOT/ALL 14 (Federal Docket Management

System), which can be reviewed at <https://www.transportation.gov/individuals/privacy/privacy-act-system-records-notices>, the comments are searchable by the name of the submitter.

II. Background

On March 1, 2023, FMCSA published a notice announcing its decision to renew exemptions for 28 individuals from the hearing standard in 49 CFR 391.41(b)(11) to operate a CMV in interstate commerce and requested comments from the public (88 FR 13007). The public comment period ended on March 31, 2023, and no comments were received.

FMCSA has evaluated the eligibility of these applicants and determined that renewing these exemptions would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved by complying with § 391.41(b)(11).

The physical qualification standard for drivers regarding hearing found in § 391.41(b)(11) states that a person is physically qualified to drive a CMV if that person first perceives a forced whispered voice in the better ear at not less than 5 feet with or without the use of a hearing aid or, if tested by use of an audiometric device, does not have an average hearing loss in the better ear greater than 40 decibels at 500 Hz, 1,000 Hz, and 2,000 Hz with or without a hearing aid when the audiometric device is calibrated to American National Standard (formerly ASA Standard) Z24.5-1951.

This standard was adopted in 1970 and was revised in 1971 to allow drivers to be qualified under this standard while wearing a hearing aid (35 FR 6458, 6463 (Apr. 22, 1970) and 36 FR 12857 (July 8, 1971), respectively).

III. Discussion of Comments

FMCSA received no comments in this proceeding.

IV. Conclusion

Based upon its evaluation of the 28 renewal exemption applications, FMCSA announces its decision to exempt the following drivers from the hearing requirement in § 391.41 (b)(11).

In accordance with 49 U.S.C. 31136(e) and 31315(b), the following groups of drivers received renewed exemptions in the month of March and are discussed below:

As of March 3, 2023, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following 14 individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers (88 FR 13007):

Kevin Beacham (MD)
Mark Cole (MD)
Joseph Conversa (IL)
Chauncey Crawford (OH)
Tyjuan Davis (VA)
John Dumars (FL)
Scott Friede (TX)
Calvin Gousby (NV)
Joshua Johnson (CO)
Kimothy McLoed (GA)
Dustin R. Miller, (MI)
Taryn Peterson (IA)
Nolen Soler (NE)
Brandon Veronie (LA)

The drivers were included in docket numbers FMCSA-2012-0154, FMCSA-2014-0103, FMCSA-2014-0106, FMCSA-2015-0328, FMCSA-2016-0003, FMCSA-2018-0135, FMCSA-2018-0136, FMCSA-2020-0027, or FMCSA-2020-0028. Their exemptions were applicable as of March 3, 2023 and will expire on March 3, 2025.

As of March 10, 2023, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following two individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers (88 FR 13007): Susan D. Helgerson (WI) and David A. Helgerson (WI).

The drivers were included in docket number FMCSA-2013-0124. Their exemptions were applicable as of March 10, 2023 and will expire on March 10, 2025.

As of March 13, 2023, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following two individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers (88 FR 13007): John L. Huey (GA) and Scott M. Putnam (FL)

The drivers were included in docket number FMCSA-2014-0107. Their exemptions were applicable as of March 13, 2023 and will expire on March 13, 2025.

As of March 19, 2023, and in accordance with 49 U.S.C. 31136(e) and 31315(b), Victor H. Morales (TX) has satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers (88 FR 13008).

This driver was included in docket number FMCSA-2014-0106. The exemption was applicable as of March 19, 2023 and will expire on March 19, 2025.

As of March 22, 2023, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following three individuals have satisfied the renewal conditions for obtaining an exemption

from the hearing requirement in the FMCSRs for interstate CMV drivers (88 FR 13007):

William B. Britt (TN); Lawrence Hung K. Lam (CA); and Phillip P. Shook (MS)

The drivers were included in docket number FMCSA–2018–0137. Their exemptions were applicable as of March 22, 2023 and will expire on March 22, 2025.

As of March 29, 2023, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following six individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers (88 FR 13008):

Jeremy Brandyberry (NE)
Kenneth Harris (TX)
Joseph Kelly (PA)
Timothy Laporte (SC)
Brandon Londo (TX)
Jesse Shelander (TX)

The drivers were included in docket numbers FMCSA–2013–0124, FMCSA–2014–0102, FMCSA–2014–0103, FMCSA–2014–0104, or FMCSA–2014–0106. Their exemptions were applicable as of March 29, 2023 and will expire on March 29, 2025.

In accordance with 49 U.S.C. 31315(b), each exemption will be valid for 2 years from the effective date unless revoked earlier by FMCSA. The exemption will be revoked if the following occurs: (1) the person fails to comply with the terms and conditions of the exemption; (2) the exemption has resulted in a lower level of safety than was maintained prior to being granted; or (3) continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136, 49 U.S.C. chapter 313, or the FMCSRs.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2023–10634 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

Fiscal Year 2023 Competitive Funding Opportunity: Passenger Ferry Grant Program and Ferry Service for Rural Communities Program

AGENCY: Federal Transit Administration (FTA), Department of Transportation (DOT).

ACTION: Notice of funding opportunity (NOFO).

SUMMARY: The Federal Transit Administration (FTA) announces the

opportunity to apply for \$220.2 million in competitive grants under the Fiscal Year (FY) 2023 Passenger Ferry Grant Program (Passenger Ferry Program) and Ferry Service for Rural Communities Program (Rural Ferry Program). Of the amount being made available, \$50.1 million is for the Passenger Ferry Program and approximately \$170 million is for the Rural Ferry Program. FTA may award additional funding made available to the program prior to the announcement of project selections.

DATES: Complete proposals must be submitted electronically through the *GRANTS.GOV* “APPLY” function by 11:59 p.m. Eastern time July 17, 2023. Prospective applicants should initiate the process by promptly registering on the *GRANTS.GOV* website to ensure completion of the application process before the submission deadline. Instructions for applying can be found on FTA’s website at <https://www.transit.dot.gov/funding/grants/applying/applying-fta-funding> and in the “FIND” module of *GRANTS.GOV*. The funding opportunity ID for the Passenger Ferry Program is FTA–2023–007–TPM–PassFerry and the funding opportunity ID for the Rural Ferry Program is FTA–2023–008–TPM–Rural Ferry. Mail and fax submissions will not be accepted.

FOR FURTHER INFORMATION CONTACT:

FTAFerryPrograms@dot.gov or Vanessa Williams, FTA Office of Program Management, (202) 366–4818, or Sarah Clements, FTA Office of Program Management, (202) 366–3062.

SUPPLEMENTARY INFORMATION:

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- A. Program Description
- B. Federal Award Information
- C. Eligibility Information
- D. Application and Submission Information
- E. Application Review Information
- F. Federal Award Administration Information
- G. Federal Awarding Agency Contacts
- H. Other Information

A. Program Description

This Notice of Funding Opportunity (NOFO) announces the availability of FY 2023 funding for the Passenger Ferry Grant Program (Passenger Ferry Program) and Ferry Service for Rural Communities Program (Rural Ferry Program). Both programs can be found in Federal Assistance Listing: 20.532.

Federal public transportation law (49 U.S.C. 5307(h)) authorizes FTA to award grants for passenger ferries through a competitive process. The Passenger Ferry Program provides funding to designated recipients and direct recipients under FTA’s Urbanized Area

Formula Program, as well as public entities engaged in providing public transportation passenger ferry service in urban areas that are eligible to be direct recipients. Projects funded under the program will improve the condition and quality of existing passenger ferry services, support the establishment of new passenger ferry services, and repair and modernize ferry boats, terminals, and related facilities and equipment.

Section 71103 of the Infrastructure Investment and Jobs Act (the “Bipartisan Infrastructure Law” or “BIL”) (Pub. L. 117–58) authorizes FTA to award grants for the Rural Ferry Program through a competitive process, as described in this notice. The Rural Ferry Program provides funding for capital, operating, and planning expenses to States and territories for ferry service to rural areas. Projects funded under this program will support ferry transportation service that operated a regular schedule at any time during the five-year period from March 1, 2015, to March 1, 2020, and includes at least one route segment of at least 50 sailing (nautical) miles between two rural areas. The Consolidated Appropriations Act, 2023, (Pub. L. 117–328) provides an additional \$17,500,000 for ferry service meeting the above criteria, except it is only required to serve at least two rural areas with a single route segment over 20 miles between the two rural areas and does not attribute data to an urbanized area in the National Transit Database for ferry service.

FTA recognizes that passenger ferries provide critical and cost-effective transportation links throughout the United States but face a critical backlog of state of good repair and safety investments. These programs support FTA’s priorities and objectives through investments that (1) renew our transit systems, (2) reduce greenhouse gas emissions from public transportation, (3) advance racial equity by removing transportation related disparities to all populations within a project area and increasing equitable access to project benefits, (4) maintain and create good-paying jobs with a free and fair choice to join a union, and (5) connect communities by increasing access to affordable transportation options.

FTA seeks to fund projects under the Passenger Ferry and Rural Ferry Programs that:

- Reduce greenhouse gas emissions in the transportation sector, incorporate evidence-based climate resilience measures and features, reduce the lifecycle greenhouse gas emissions from the project materials, and avoid adverse environmental impacts to air or water

quality, wetlands, and endangered species, and address the disproportionate negative environmental impacts of transportation on disadvantaged communities, consistent with Executive Order 14008, Tackling the Climate Crisis at Home and Abroad (86 FR 7619).

- Create proportional impacts to all populations in a project area, remove transportation related disparities to all populations in a project area, and increase equitable access to project benefits, consistent with Executive Order 13985, Advancing Racial Equity and Support for Underserved Communities Through the Federal Government (86 FR 7009).
- Address equity and environmental justice, particularly for communities that have experienced decades of under investment and are most impacted by climate change, pollution, and environmental hazards, consistent with Executive Order 14008, Tackling the Climate Crisis at Home and Abroad (86 FR 7619).
- Support the creation of good-paying jobs with the free and fair choice to join a union and the incorporation of strong labor standards and training and placement programs, especially registered apprenticeships, in project planning stages, consistent with Executive Order 14025, Worker Organizing and Empowerment (86 FR 22829), and Executive Order 14052, Implementation of the Infrastructure Investment and Jobs Act (86 FR 64335).
- Support wealth creation, consistent with the Department's Equity Action

Plan through the inclusion of local inclusive economic development and entrepreneurship such as the utilization of Disadvantaged Business Enterprises, Minority-owned businesses, Women-owned businesses, or section 8(a) firms.

B. Federal Award Information

Federal public transportation law (49 U.S.C. 5307(h)) authorizes \$30 million in FY 2023 contract authority funds for competitive grants under the Passenger Ferry Program. The Consolidated Appropriations Act, 2023, appropriated an additional \$15 million. Of that latter amount, \$5 million is available only for low- or zero-emission ferries or ferries using electric battery or fuel cell components and the infrastructure to support such ferries. Additionally, \$2,149,651 remains available for allocation from the amounts made available in FY 2022 and an additional \$3,000,000 from FY 2016 is available for reallocation. FTA may award additional funding made available to the program prior to the announcement of project selections. In FY 2022, FTA received 25 eligible applications from 13 States and 1 territory requesting \$153 million in Federal Passenger Ferry Program funds. Eight projects were funded at a total of \$34.4 million.

Division J of the BIL provides an advance appropriation of \$200 million in FY 2023 funds for the Rural Ferry Program. Of that amount, \$3,980,000 is for FTA oversight, and \$20,000 is transferred to the USDOT Office of the Inspector General. Additionally, \$43,452,559 of FY 2023 funding was

awarded under the FY 2022 NOFO, making \$152,547,441 available for award. Furthermore, the FY 2023 Consolidated Appropriations Act appropriated an additional \$17,500,000 that may be allocated to passenger ferry service that serves at least two rural areas with a single segment over 20 miles between the two rural areas and that is not otherwise eligible for funding under the Passenger Ferry Program.

In FY 2022, FTA received 8 eligible applications from 4 States requesting \$259 million in Federal Rural Ferry Program funds. All 8 projects were funded at a total of \$252 million.

FTA will grant pre-award authority to incur costs for selected projects beginning on the date the FY 2023 project selections are announced on FTA's website. A project selected under the Rural Ferry Program that is a continuation of a project that was selected through the FY 2022 NOFO will be granted pre-award authority from the time of the FY 2022 selection announcement. Funds are available for obligation for five years after the fiscal year in which the awards are announced. Except for any proposed continuation of Rural Ferry projects funded from the FY 2022 NOFO, funds are available only for projects that have not already incurred costs prior to the announcement of project selections.

C. Eligibility Information

1. Eligible Applicants

SUMMARY TABLE

Program	Eligible applicants
Passenger Ferry Program	Designated Recipients of section 5307 Funding. Direct Recipients of section 5307 Funding. Public Entities engaged in providing public transportation passenger ferry service in urban areas that are eligible to be a Direct Recipient.
Rural Ferry Program	States and Territories.

Eligible applicants for the Passenger Ferry Program are: (1) designated recipients as defined in FTA Circular “Urbanized Area Formula Program: Program Guidance and Application Instructions” (FTA.C.9030.1E), (2) direct recipients of FTA’s Urbanized Area Formula Grants, and (3) public entities engaged in providing public transportation passenger ferry service in urban areas that are eligible to be direct recipients.

Eligible applicants for the Rural Ferry Program are States and Territories in which eligible service is operated. For the \$152.6 million made available under

Division J of the BIL, eligible service includes passenger ferry service that operated a regular schedule at any time between March 1, 2015, and March 1, 2020, and operated at least one segment between two rural areas located more than 50 sailing (nautical) miles apart. FTA defines a regular schedule as a published schedule for either seasonal or year-round ferry service. For the \$17.5 million appropriated in the Consolidated Appropriations Act, 2023, eligible service also includes any passenger ferry service that operated a regular schedule at any time between March 1, 2015, and March 1, 2020, and

operated at least one segment more than 20 miles between two rural areas. Applicants in both categories must not have attributed data to an urbanized area in their most recent report to the National Transit Database for their ferry services. Applicants must document their eligibility for the Rural Ferry Program by providing the following:

(A) Documentation such as dated and published sailing schedules to demonstrate the operation of regular scheduled service at any time during the five-year period ending March 1, 2020.

(B) Documentation such as route maps to demonstrate provision of service for at least one direct segment between two rural areas

that meet the distance requirements described above (either at least 50 or 20 nautical sailing miles) during the five-year period ending March 1, 2020.

FTA will confirm the segment length based upon data reported to the National Census of Ferry Operators maintained by the Bureau of Transportation Statistics.

An eligible applicant that does not currently have an active grant with FTA will, upon selection, be required to work with an FTA regional office to establish its organization as an active grant recipient. This process may require additional documentation to support the organization's technical, financial, and legal capacity to receive and administer Federal funds under this program.

2. Cost Sharing or Matching

a. The maximum Federal share for capital projects selected under each program is 80 percent of the net project cost, with the exceptions described in paragraphs b and c below, per 49 U.S.C. 5323. The maximum Federal share for planning projects selected under the Rural Ferry Program is 80 percent. There is no maximum Federal share for operating projects selected under the Rural Ferry Program in FY 2023; however, similar to FY 2022, FTA will

require the State or locality to provide, at a minimum, 75 percent of the three-year average prior to the pandemic (2017, 2018, and 2019) on an annual basis to support ferry service for the period supported by the grant. For example, if a State or locality normally provided \$1 million in operating assistance annually, an applicant should include at least \$750,000 in State or local operating assistance.

b. The maximum Federal share is 85 percent of the net project cost of acquiring vehicles (including clean-fuel or alternative fuel vehicles) for purposes of complying with or maintaining compliance with the Clean Air Act (CAA) or the Americans with Disabilities Act (ADA) of 1990.

c. The maximum Federal share is 90 percent of the net project cost of acquiring, installing, or constructing vehicle-related equipment or facilities (including clean fuel or alternative-fuel vehicle-related equipment or facilities) for purposes of complying with or maintaining compliance with the ADA or CAA. The award recipient must itemize the cost of specific, discrete, vehicle-related equipment associated with compliance with the ADA or CAA to be eligible for the maximum 90 percent Federal share for these costs.

Eligible sources of non-Federal matching funds include:

- i. Cash from non-governmental sources other than revenues from providing the ferry services (such as fare revenues, vehicle, or cargo charges, etc.);
- ii. Non-farebox revenues from the operation of public transportation service, such as the sale of advertising and concession revenues;
- iii. Monies received under a service agreement with a State or local social service agency or private social service organization;
- iv. Undistributed cash surpluses, replacement or depreciation cash funds, reserves available in cash, or new capital;
- v. Amounts appropriated or otherwise made available to a department or agency of the Government (other than the USDOT), that are eligible to be expended for public transportation;
- vi. In-kind contributions integral to the project;
- vii. Revenue bond proceeds for a capital project, with prior FTA approval; and
- viii. Transportation Development Credits (formerly referred to as Toll Revenue Credits).

If an applicant proposes a Federal share greater than 80 percent, the applicant must clearly explain why the project is eligible for the proposed Federal share.

3. Eligible Projects

SUMMARY TABLE

Program	Eligible projects
Passenger Ferry Program	Capital Projects—purchase, construction, replacement, or rehabilitation of ferries, terminals, related infrastructure, and related equipment (including electric or low-emitting ferry vessels and related infrastructure).
Rural Ferry Program	Capital Projects—purchase, construction, replacement, or rehabilitation of ferries, terminals, related infrastructure, and related equipment (including electric or low-emitting ferry vessels and related infrastructure). Planning Projects. Operating Projects.

3A. Passenger Ferry Program—Eligible Projects

Under the Passenger Ferry Program, eligible projects are capital projects for the purchase, construction, replacement, or rehabilitation of ferries, terminals, related infrastructure, and related equipment (including fare equipment and communication devices). Projects are required to support a passenger ferry service that serves an urbanized area and may include services that operate between an urbanized area and rural areas. Ferry systems that accommodate cars must also accommodate walk-on passengers to be eligible for funding. Operating costs and planning projects are not eligible.

Under the Passenger Ferry Program only, recipients are permitted to use up to 0.5 percent of their grant award to pay for not more than 80 percent of the cost for workforce development activities eligible under Federal public transportation law (49 U.S.C. 5314(b)) and an additional 0.5 percent for costs associated with training at the National Transit Institute. Applicants must identify the proposed use of funds for these activities in the project proposal and identify them separately in the project budget. Supportive services, such as childcare and transportation assistance for participants, may be an eligible use of program funds under 49 U.S.C. 5314(b). FTA has published clarifying frequently asked questions regarding supportive services on its

website at <https://www.transit.dot.gov/funding/grants/federal-transit-administration-faqs-supportive-services>.

3B. Rural Ferry Program—Eligible Projects

Under the Rural Ferry Program, eligible projects are capital, operating, or planning assistance. Eligible capital projects include the purchase, construction, replacement, or rehabilitation of ferries, terminals, related infrastructure, and related equipment (including fare equipment and communication devices). Only net operating expenses are eligible for assistance. Net operating expenses are those expenses that remain after the provider subtracts operating revenues from eligible operating expenses. States may further define what constitutes

operating revenues, but, at a minimum, operating revenues must include farebox revenues and other fees generated directly by the ferry service such as vehicle fares, cargo fees, and cabin fees. Farebox revenues are fares paid by riders, including those who are later reimbursed by a human service agency or other user-side subsidy arrangement. For more information, please see FTA Circular 9040.1G at <https://www.transit.dot.gov/regulations-and-guidance/fta-circulars/formula-grants-rural-areas-program-guidance-and-application>. Eligible projects are not required to be implemented on the same route segments that resulted in applicant eligibility (e.g., the project need not be implemented on a segment of more than 20 or 50 sailing (nautical) miles). Ferry systems that accommodate cars must also accommodate walk-on passengers to be eligible for funding. Walk-on passengers are defined as passengers who board the vessel unaccompanied by any motor vehicle in which they may have arrived at the ferry terminal and which remains behind after ferry departure.

D. Application and Submission Information

1. Address To Request Application Package

Applications may be accessed at *GRANTS.GOV* and must be submitted electronically through *GRANTS.GOV*. General information for accessing and submitting applications through *GRANTS.GOV* can be found at <https://www.fta.dot.gov/howtoapply> along with specific instructions for the forms and attachments required for submission. Mail or fax submissions will not be accepted. The required SF-424 Application for Federal Assistance can be downloaded from *GRANTS.GOV* and the required supplemental form can be downloaded from *GRANTS.GOV* or the FTA website at <https://www.transit.dot.gov/grants/fta-ferry-programs>.

2. Content and Form of Application Submission

a. Proposal Submission

A complete proposal submission consists of two forms: (1) the SF-424 Application for Federal Assistance; and (2) the FY 2023 Passenger Ferry Program and Rural Ferry Program supplemental form. If an applicant is submitting different proposals to different programs, the applicant must submit an application for each project to each program separately. The supplemental form and any supporting documents must be attached to the "Attachments"

section of the SF-424. The application must include responses to all sections of the SF-424 Application for Federal Assistance and the supplemental form, unless designated as optional. The information on the supplemental form will be used to determine applicant and project eligibility for the program, and to evaluate the proposal against the selection criteria described in part E of this notice. Failure to submit the information as requested can delay review or disqualify the application.

FTA will accept only one supplemental form per SF-424 submission. FTA encourages States and other applicants to consider submitting a single supplemental form that includes multiple activities as one project to be evaluated as a consolidated proposal. If a State or other applicant chooses to submit separate proposals for individual consideration by FTA, each proposal must be submitted using a separate SF-424 and supplemental form.

Applicants may attach additional supporting information to the SF-424 submission, including but not limited to documentation supporting the applicant's eligibility for the grant programs, letters of support, project budgets, fleet status reports, or excerpts from relevant planning documents. Supporting documentation should be described and referenced by file name in the appropriate response section of the supplemental form, or it may not be reviewed.

Information such as applicant name, Federal amount requested, local match amount, and description of areas served may be requested in varying degrees of detail on both the SF-424 and supplemental form. Applicants must fill in all fields unless otherwise stated on the forms. Applicants should not place N/A or "refer to attachment" in lieu of typing in responses in the field sections. If information is copied into the supplemental form from another source, applicants should verify that pasted text is fully captured on the supplemental form and has not been truncated by the character limits built into the form. Applicants should use both the "Check Package for Errors" and the "Validate Form" validation buttons on both forms to check all required fields on the forms and ensure that the Federal and local amounts specified are consistent.

b. Application Content

The SF-424 Application for Federal Assistance and the supplemental form will prompt applicants for the required information:

a. Applicant name.

b. Unique entity identifier (UEI) (generated by *SAM.GOV*).

c. Key contact information (including contact name, address, email address, and phone).

d. Congressional district(s) in which the project is located.

e. Project information (including title, executive summary, and type).

f. A detailed description of the need for the project.

g. A detailed description of how the project will support the program objectives.

h. Evidence that the project is consistent with local and regional planning objectives.

i. Evidence that the applicant can provide the non-Federal cost share.

j. A description of the technical, legal, and financial capacity of the applicant.

k. A detailed project budget that shows how different funding sources will share in each activity. The budget should identify other Federal funds the applicant is applying for or has been awarded, if any, that the applicant intends to use.

l. An explanation of the scalability of the project.

m. Details on the non-Federal matching funds.

n. For any application for operating assistance under the Rural Ferry program, the applicant should provide the amount of State or local funds provided for operating assistance for the three years of operation prior to the start of the pandemic, January 20, 2020. Applicants, at their discretion, may provide the three years of data ending on the last day of the applicant's fiscal year ending prior to January 20, 2020; end of the Federal fiscal year ending prior to January 20, 2020; or ending January 20, 2020.

o. A detailed project timeline.

p. Address all the applicable criteria and priority considerations identified in section E.

3. Unique Entity Identifier and System for Award Management (SAM)

Each applicant is required to: (1) be registered in *SAM.GOV* before submitting an application; (2) provide a valid unique entity identifier in its application; and (3) continue to maintain an active SAM registration with current information at all times during which the applicant has an active Federal award or an application or plan under consideration by FTA. FTA may not make an award until the applicant has complied with all applicable unique entity identifier and SAM requirements. If an applicant has not fully complied with the requirements by the time FTA is ready to make an award, FTA may determine that the applicant is not qualified to receive an award and use that determination as a basis for making a Federal award to another applicant. These requirements do not apply if the applicant has an exception approved by FTA or the U.S. Office of Management

and Budget under 2 CFR 25.110(c) or (d).

All applicants must provide a unique entity identifier provided by SAM. Registration in SAM may take as little as 3–5 business days, but since there could be unexpected steps or delays (for example, if there is a need to obtain an Employer Identification Number), FTA recommends allowing ample time, up to several weeks, for completion of all steps. For additional information on obtaining a unique entity identifier, please visit <https://www.sam.gov>.

4. Submission Dates and Times

Project proposals must be submitted electronically through *GRANTS.GOV* by 11:59 p.m. Eastern Time on July 17, 2023. *GRANTS.GOV* attaches a time stamp to each application at the time of submission. Mail and fax submissions will not be accepted.

FTA urges applicants to submit applications at least 72 hours prior to the deadline to allow time to correct any problems that may have caused either *GRANTS.GOV* or FTA systems to reject the submission. Proposals submitted after the deadline will be considered only if lateness was due to extraordinary circumstances not under the applicant's control. Deadlines will not be extended due to scheduled website maintenance. *GRANTS.GOV* scheduled maintenance and outage times are announced on the *GRANTS.GOV* website.

Within 48 hours after submitting an electronic application, the applicant should receive an email message from *GRANTS.GOV* with confirmation of successful transmission to *GRANTS.GOV*. If a notice of failed validation or incomplete materials is received, the applicant must address the reason for the failed validation, as described in the email notice, and resubmit before the submission deadline. If making a resubmission for any reason, include all original attachments regardless of which attachments were updated and check the box on the supplemental form indicating this is a resubmission.

Applicants are encouraged to begin the process of registration on the *GRANTS.GOV* site well in advance of the submission deadline. Registration is a multi-step process, which may take several weeks to complete before an application can be submitted. Registered applicants may still be required to take steps to keep their registration up to date before submissions can be made successfully as (1) registration in SAM is renewed annually; and (2) persons making submissions on behalf of the Authorized Organization Representative (AOR) must be authorized in

GRANTS.GOV by the AOR to make submissions.

5. Funding Restrictions

Funds made available under the Passenger Ferry Program may not be used to fund operating expenses, planning, or preventive maintenance. Any project that does not include the purchase, construction, replacement, or rehabilitation of ferries, terminals, related infrastructure, or related equipment is not eligible. Applicants to the Rural Ferry Program may apply for capital, operating, or planning assistance.

Except for continuation of projects funded under the FY 2022 Rural Ferry Program, funds made available under this NOFO cannot be used to reimburse applicants for otherwise eligible expenses incurred prior to the posting of project selections on FTA's website and the corresponding issuance of pre-award authority. Allowable direct and indirect expenses must be consistent with the Government-wide Uniform Administrative Requirements, Cost Principles, and Audit Requirements for Federal Awards (2 CFR part 200) and FTA Circular 5010.1E.

As required by statute, an eligible ferry service that receives funds from a State under the Rural Ferry Program shall not be attributed to an urbanized area for purposes of apportioning funds under chapter 53 of title 49, U.S. Code. In addition, an eligible service that receives funds from a State under the Rural Ferry Program shall not receive funds apportioned under section 5336 or 5337 of title 49, U.S. Code, in the same fiscal year.

6. Other Submission Requirements

Applicants are encouraged to identify scaled funding options in case insufficient funding is available to fund a project at the full requested amount. If an applicant advises that a project is scalable, the applicant must provide an appropriate minimum funding amount that will fund an eligible project that achieves the objectives of the program and meets all relevant program requirements. The applicant must provide a clear explanation of how the project budget would be affected by a reduced award. FTA may award a lesser amount whether or not a scalable option is provided.

The Department may share application information within the Department or with other Federal agencies if the Department determines that sharing is relevant to the respective program's objectives.

E. Application Review Information

1. Criteria

Projects will be evaluated primarily on the responses provided in the supplemental form. Additional information may be provided to support the responses; however, any additional documentation must be directly referenced on the supplemental form, including the file name where the additional information can be found. FTA will evaluate project proposals based on the criteria described in this notice.

a. Demonstration of Need

Applications for capital expenses to the Passenger Ferry Program or Rural Ferry Program will be evaluated based on the quality and extent to which they demonstrate how the proposed project will address an unmet need for capital investment in passenger ferry vehicles, equipment, or facilities. FTA will also evaluate the project's impact on service delivery and whether the project represents a one-time or periodic need that cannot reasonably be funded from FTA formula program allocations or State or local resources. In evaluating applications, FTA will consider, among other factors, certain project-specific criteria as outlined below:

i. For vessel replacement or rehabilitation projects (including low or zero-emission ferries):

- The age of the asset to be replaced or rehabilitated by the proposed project, relative to its useful life—those applicants that are already FTA grantees should reference the useful life benchmark for the vehicles to be replaced identified in their Transit Asset Management Plan and reported to the National Transit Database. Those applicants should also describe how replacing the vehicle will help them meet the state of good repair performance targets set in their Transit Asset Management (TAM) Plan.

- The condition of the asset to be replaced by the proposed project, as ascertained through inspections or otherwise, if available.

ii. For facility infrastructure improvements or related-equipment acquisitions:

- The age of the facility or equipment to be rehabilitated or replaced, relative to its useful life—those applicants that are already FTA grantees should reference the condition of the facility as reported to the National Transit Database and how the project will help you meet the state of good repair performance targets in your Transit Asset Management (TAM) Plan.

- The degree to which the proposed project will enable the agency to improve the maintenance and condition of the agency's fleet or related ferry assets.

- iii. For vessel or facility-related expansion or new service requests:

- The degree to which the proposed project addresses a current capacity constraint that is limiting the ability of the agency to provide reliable service, meet ridership demands, or maintain vessels and related equipment.

- The degree to which the proposed new service is supported by ridership demand.

For operating projects under the Rural Ferry Program:

- The degree to which the application addresses how additional operating resources will lead to more reliable or improved service, or meet additional service demands.

- The financial need demonstrated by the applicant, including actual or projected need to maintain or initiate ferry service and a description of how existing operating resources are insufficient to meet the need.

- For expansion operating projects, projected ridership on the new service and the methodology used by the applicant to determine the projection.

For planning projects under the Rural Ferry Program:

- The degree to which the application addresses how planning resources will lead to more reliable or improved service, or meet additional service demands.

b. Demonstration of Benefits

All Applications will be evaluated based on how the ferry project will accomplish one or more of the following: (1) enhance the safety of existing ferry systems, (2) improve the state of good repair of the existing system, (3) provide additional transportation options that foster community development and access to economic opportunities, and/or (4) improve the quality of transit service to underserved communities.

Additionally, all applications will be evaluated on their support for walk-on passengers. Walk-on passengers are defined as passengers who board the vessel unaccompanied by any motor vehicle in which they may have arrived at the ferry terminal and which remains behind after ferry departure. The support for walk-on passengers will be evaluated as follows:

For replacement or rehabilitation projects, benefits will be evaluated in part based on the percentage of riders that are walk-on compared to passengers

using the service to transport automobiles.

For expansion projects, benefits will be evaluated in part based on what convenient infrastructure is provided at the origin and destination of the service and at any intermediary stops that supports transit and intercity bus riders, pedestrians, or bicycles. Supporting documentation should include data that demonstrates the number of trips (passengers and vehicles), the number of walk-on passengers, and the frequency of transfers to other modes, if applicable.

In addition to the above five elements, projects for low- or zero-emission ferries under any program or projects for operating assistance under the Rural Ferry program will be evaluated as follows:

For low- or zero-emission ferries, applicants should demonstrate how the proposed ferries or infrastructure will reduce the emission of particulates and other pollutants that create local air pollution, which leads to local environmental health concerns, smog, and unhealthy ozone concentrations. Applicants should also demonstrate how the proposed ferries or infrastructure will reduce emissions of greenhouse gases from ferry operations. Projects that propose the use of zero-emission ferries and related infrastructure for producing zero onboard emissions during normal operations will be more competitive.

For operating projects under the Rural Ferry Program, applicants should address and document how the requested operating funds will be used to augment, and not replace, existing State or local operating funds.

c. Planning and Local/Regional Prioritization

Applicants that are already FTA recipients and are seeking a capital grant should demonstrate that the project is included in the investment prioritization of their Transit Asset Management (TAM) Plan.

Applicants must demonstrate how the proposed project is consistent with local and regional planning documents and identified priorities. This will involve assessing whether the project is consistent with the transit priorities identified in the long-range transportation plan and the State and Metropolitan Transportation Improvement Program (STIP/TIP). Applicants should note if the project could not be included in the financially constrained STIP or TIP due to lack of funding, and if selected that the project can be added to the federally approved STIP before grant award.

FTA encourages applicants to demonstrate State or local support by including letters of support from State departments of transportation, local transit agencies, local government officials and public agencies, local non-profit or private sector organizations, and other relevant stakeholders.

Applications that include letters of support will be viewed more favorably than those that do not. For FTA to fully consider a letter of support, the letter must be included in the application package. In an area with both ferry and other public transit operators, FTA will evaluate whether project proposals demonstrate coordination with and support of other related projects within the applicant's Metropolitan Planning Organization (MPO) or the geographic region within which the proposed project will operate.

d. Local Financial Commitment

Applicants must identify the source of the local cost share and describe whether such funds are currently available for the project or will need to be secured if the project is selected for funding. FTA will consider the availability of the local cost share as evidence of local financial commitment to the project. Additional consideration will be given to those projects for which local funds have already been made available or reserved. Applicants should submit evidence of the availability of funds for the project, by including, for example, a board resolution, letter of support from the State, a budget document highlighting the line item or section committing funds to the proposed project, or other documentation of the source of non-Federal funds.

An applicant may provide documentation of previous and recent local investments in the project, which cannot be used to satisfy non-Federal matching requirements, as evidence of local financial commitment.

Applicants that request a Federal share for a capital project greater than 80 percent must clearly explain why the project is eligible for the proposed Federal share. For planning projects under the Rural Ferry Program, the Federal share may not exceed 80 percent. For operating projects under the Rural Ferry Program, there is no maximum Federal share to a grant awarded under this program, however, the applicant must maintain the non-Federal funding levels described in section C of this notice.

e. Project Implementation Strategy

Projects will be evaluated based on the extent to which the project is ready

to implement within a reasonable period of time and whether the applicant's proposed implementation plans are reasonable and complete.

In assessing whether the project is ready to implement within a reasonable period of time, FTA will consider whether the project qualifies for a Categorical Exclusion, or whether the required environmental work has been initiated or completed for projects that require an Environmental Assessment or Environmental Impact Statement under the National Environmental Policy Act of 1969. As such, applicants should submit information describing the project's anticipated path and timeline through the environmental review process. If the project will qualify as a Categorical Exclusion, the applicant must say so explicitly in the application. The proposal must also state whether grant funds can be obligated within 12 months from time of award, if selected, and if necessary, the timeframe under which the TIP and STIP can be amended to include the proposed project. Additional consideration will be given to projects for which grant funds can be obligated within 12 months from time of award.

In assessing whether the proposed implementation plans are reasonable and complete, FTA will review the proposed project implementation plan, including all necessary project milestones and the overall project timeline. For projects that will require formal coordination, approvals, or permits from other agencies or project partners, the applicant must demonstrate coordination with these organizations and their support for the project, such as through letters of support.

f. Technical, Legal, and Financial Capacity

Applicants must demonstrate that they have the technical, legal, and financial capacity to undertake the project. FTA will review relevant oversight assessments and records to determine whether there are any outstanding legal, technical, or financial issues with the applicant that would affect the outcome of the proposed project. Additional information on the compliance requirements for these grants appears later in this notice.

Applicants with outstanding legal, technical, or financial compliance issues from an FTA compliance review or FTA grant-related Single Audit finding must explain how corrective actions taken will mitigate negative impacts on the project.

2. Review and Selection Process

FTA technical evaluation committees will evaluate proposals using the project evaluation criteria. FTA staff may request additional information from applicants, if necessary. After consideration of the findings of the technical evaluation committees, FTA will determine the final selection of projects for program funding. In determining the allocation of program funds, FTA may consider geographic diversity, diversity in the size of the transit systems receiving funding, walk-on vs. vehicle boardings for the impacted service, and the applicant's receipt of other competitive awards. FTA will also consider whether the project will include low or zero-emission ferries, including ferries using electric battery or fuel cell components and the infrastructure to support such ferries. FTA may consider capping the amount a single applicant may receive.

After applying the above criteria, to address climate change and sustainability, FTA will give priority consideration to applications that are expected to create significant community benefits relating to the environment, including those projects that incorporate low or no emission technology or specific elements to address greenhouse gas emissions as well as disproportionate negative impacts of climate change and pollution on disadvantaged communities.

FTA will also provide priority consideration for applicants that describe how their projects support workforce development, job quality, and wealth creation as follows:

Applicants for facility projects should identify whether they will commit to registered apprenticeship positions and use apprentices on the funded project, sometimes called an apprenticeship utilization requirement (*e.g.*, requiring that a certain percent of all labor hours will be performed by registered apprentices). Applicants should also detail partnerships with high-quality workforce development programs with supportive services¹ to help train, place, and retain underrepresented communities in jobs and registered apprenticeships on the project.

In addition to the above, facility projects over \$35 million in total project cost, should identify whether the project will use a Project Labor/Community Workforce Agreement and whether the recipient commits to participate in the U.S. Department of Labor's Office of Federal Contract Compliance Programs (OFCCP) Mega Construction Project Program if selected by OFCCP (see F.2.e. *Federal Contract Compliance*).

FTA will also give priority consideration to projects that support the Justice40 initiative, <https://www.transportation.gov/equity-Justice40>. In support of Executive Order 14008, DOT has been developing a geographic definition of Historically Disadvantaged Communities as part of its implementation of the Justice40 Initiative. Consistent with OMB's Interim Guidance for the Justice40 Initiative, Historically Disadvantaged Communities include (a) certain qualifying census tracts, (b) any Tribal land, or (c) any territory or possession of the United States. DOT is providing a mapping tool to assist applicants in identifying whether a project is located in a Historically Disadvantaged Community Transportation Disadvantaged Census Tracts (<https://www.arcgis.com/apps/dashboards/d6f90dfcc8b44525b04c7ce748a3674a>). Alternatively, applicants may also choose to use the Climate and Economic Justice Screening Tool (CEJST), provided by the Council on Environmental Quality. This tool can be found at <https://screeningtool.geoplatform.gov>. Use of either mapping tool is optional; applicants may provide an image from the map tool outputs, or alternatively, consistent with OMB's Interim Guidance, applicants can supply quantitative, demographic data of their ridership demonstrating the percentage of their ridership that meets the criteria for disadvantage described in Executive Order 14008. Examples of indicators for Historically Disadvantaged Communities that an applicant could address using geographic or demographic information include percentages of low income, high or persistent poverty, high unemployment and underemployment, racial and ethnic residential segregation, linguistic isolation, high housing cost burden and substandard housing, and high transportation cost burden and/or low transportation access. Additionally, in support of the Justice40 Initiative, the applicant also should provide evidence of strategies that the applicant has used in the planning process to seek out and consider the needs of those historically disadvantaged and underserved by existing transportation systems. For technical assistance using the mapping tool, please contact GMO@dot.gov.

Due to funding limitations, projects that are selected for funding may receive less than the amount originally requested, even if an application did not present a scaled project option. In those cases, applicants must be able to demonstrate that the proposed projects

are still viable and can be completed with the amount awarded.

3. Integrity and Performance Review

Prior to making an award with a total amount of Federal share greater than the simplified acquisition threshold (currently \$250,000), FTA is required to review and consider any information about the applicant that is in the Federal Awardee Performance and Integrity Information Systems (FAPIIS) accessible through SAM.GOV. An applicant may review and comment on information about itself that a Federal awarding agency previously entered. FTA will consider any comments by the applicant, in addition to the other information in FAPIIS, in making a judgment about the applicant's integrity, business ethics, and record of performance under Federal awards when completing the review of risk posed by applicants as described in 2 CFR 200.206.

F. Federal Award Administration Information

1. Federal Award Notices

Final project selections will be posted on the FTA website. Only proposals from eligible recipients for eligible activities will be considered for funding. There is no minimum or maximum grant award amount; however, FTA intends to fund as many meritorious projects as possible. Due to funding limitations, projects that are selected for funding may receive less than the amount originally requested. In those cases, applicants must be able to demonstrate that the proposed projects are still viable and can be completed with the amount awarded.

Recipients should contact their FTA Regional Office (<https://www.transit.dot.gov/about/regional-offices/regional-offices>) for additional information regarding allocations for projects under the Ferry Programs.

2. Administrative and National Policy Requirements

i. Pre-Award Authority

At the time the project selections are announced, FTA will extend pre-award authority for the selected projects consistent with 2 CFR 200.458. Except for continuations of projects selected under the FY 2022 Rural Ferry Program, there is no blanket pre-award authority for these projects before announcement, and pre-award authority cannot be used prior to FTA issuance of pre-award authority. Note, for projects selected under the FY 2022 Rural Ferry Program, pre-award authority is only permissible for activities included and approved in

the application submitted to that competition. FTA does not provide pre-award authority for competitive funds until projects are selected and even then, there are Federal requirements that must be met before costs are incurred. For more information about FTA's policy on pre-award authority, please see FTA's 2023 Apportionment Notice (88 FR 23117).

ii. Grant Requirements

If selected, awardees will apply for a grant through FTA's Transit Award Management System (TrAMS). All Passenger Ferry Program recipients are subject to the grant requirements of the Urbanized Area Formula Grant program (49 U.S.C. 5307). All Rural Ferry Program recipients are subject to the grant requirements of the Rural Area Formula Grant Program (49 U.S.C. 5311) as applicable, FTA's Master Agreement for financial assistance awards, the annual Certifications and Assurances required of applicants, FTA Circular "Urbanized Area Formula Program: Program Guidance and Application Instructions" (FTA.C.9030.1E) or FTA Circular "Formula Grants for Rural Areas" (FTA.C.9040.1G). All recipients must also follow the FTA Award Management Requirements Circular (FTA.C.5010.1) and the labor protections required by Federal public transportation law (49 U.S.C. 5333(b)). All these documents are available on FTA's website. Technical assistance regarding these requirements is available from each FTA regional office.

iii. Buy America and Domestic Preferences for Infrastructure Projects

As expressed in Executive Order 14005, "Ensuring the Future Is Made in All of America by All of America's Workers" (86 FR 7475), the Executive Branch should maximize, consistent with law, the use of goods, products, and materials produced in, and services offered in, the United States. Therefore, all capital procurements must comply with FTA's Buy America requirements (49 U.S.C. 5323(j)), which require that all iron, steel, and manufactured products be produced in the United States. In addition, any award must comply with the Build America, Buy America Act (BABA) (Pub. L. 117–58, sections 70901–27). The BABA provides that none of the funds provided under an award made pursuant to this notice may be used for a project unless all iron, steel, manufactured products, and construction materials are produced in the United States. FTA's Buy America requirements are consistent with BABA requirements for iron, steel, and manufactured products.

Any proposal that will require a waiver of any domestic preference standard must identify the items for which a waiver will be sought in the application. Applicants should not proceed with the expectation that waivers will be granted.

iv. Civil Rights and Title VI

As a condition of a grant award, grant recipients should demonstrate that the recipient has a plan for compliance with civil rights obligations and nondiscrimination laws, including title VI of the Civil Rights Act of 1964 (49 CFR part 21), the Americans with Disabilities Act of 1990 (ADA), section 504 of the Rehabilitation Act, other civil rights requirements, and all implementing regulations. This should include a current Title VI plan, completed Community Participation Plan (alternatively called a Public Participation Plan and often part of the overall Title VI program plan), if applicable. DOT's and the applicable Operating Administrations' Office of Civil Rights may work with awarded grant recipients to ensure full compliance with Federal civil rights requirements.

v. Disadvantaged Business Enterprise

Projects that include ferry acquisitions are subject to the transit vehicle manufacturer (TVM) rule of the Disadvantaged Business Enterprise (DBE) program regulations (49 CFR 26.49). The TVM rule requires recipients procuring transit vehicles, including ferries, to limit eligible bidders to certified TVMs. To become a certified TVM, a manufacturer of transit vehicles must submit a DBE program plan and annual goal to FTA for approval. A list of certified TVMs is posted on FTA's web page at <https://www.transit.dot.gov/TVM>. Recipients should contact FTA before accepting bids from entities not appearing on this list.

In lieu of restricting eligibility to certified TVMs, a recipient may, with FTA's approval, establish project-specific goals for DBE participation in the procurement of transit vehicles.

For more information on DBE requirements, please contact Monica McCallum, FTA Office of Civil Rights, 206–220–7519, Monica.McCallum@dot.gov.

vi. Federal Contract Compliance

As a condition of grant award and consistent with E.O. 11246, Equal Employment Opportunity (30 FR 12319, and as amended), all Federally-assisted construction contractors are required to make good faith efforts to meet the goals

of 6.9 percent of construction project hours being performed by women, in addition to goals that vary based on geography for construction work hours and for work being performed by people of color. Under section 503 of the Rehabilitation Act and its implementing regulations, affirmative action obligations for certain contractors include an aspirational employment goal of 7 percent workers with disabilities.

The U.S. Department of Labor's Office of Federal Contract Compliance Programs (OFCCP) is charged with enforcing Executive Order 11246, section 503 of the Rehabilitation Act of 1973, and the Vietnam Era Veterans' Readjustment Assistance Act of 1974. OFCCP has a Mega Construction Project Program through which it engages with project sponsors as early as the design phase to help promote compliance with non-discrimination and affirmative action obligations. OFCCP may identify construction projects that receive an award under this notice that have a project cost above \$35 million to participate in OFCCP's Mega Construction Project Program. If selected and the applicant agrees to participate, OFCCP will ask selected project sponsors to make clear to prime contractors in the pre-bid phase that award terms may require their participation in the Mega Construction Project Program. Additional information on how OFCCP makes their selections for participation in the Mega Construction Project Program is outlined under "Scheduling" on the Department of Labor website: <https://www.dol.gov/agencies/ofccp/faqs/construction-compliance>.

vii. Planning

FTA encourages applicants to notify the appropriate State Departments of Transportation and MPOs in areas likely to be served by the project funds made available under these initiatives and programs. Selected projects must be incorporated into the long-range plans and transportation improvement programs of States and metropolitan areas before they are eligible for FTA funding. As described under the evaluation criteria, FTA will consider whether a project is consistent with or already included in these plans when evaluating a project.

viii. Standard Assurances

The applicant assures that it will comply with all applicable Federal statutes, regulations, executive orders, directives, FTA circulars, and other Federal administrative requirements in carrying out any project supported by

the FTA grant. The applicant acknowledges that it is under a continuing obligation to comply with the terms and conditions of the grant agreement issued for its project with FTA. The applicant understands that Federal laws, regulations, policies, and administrative practices might be modified from time to time and may affect the implementation of the project. The applicant agrees that the most recent Federal requirements will apply to the project, unless FTA issues a written determination otherwise. The applicant must submit the Certifications and Assurances before receiving a grant if it does not have current certifications on file.

3. Reporting

Post-award reporting requirements include the electronic submission of Federal Financial Reports and Milestone Progress Reports. Applicants should include goals, targets, and indicators referenced in their applications to the project in the Executive Summary of the TrAMS application. Recipients or beneficiaries of funds made available through this NOFO are also required to regularly submit data to the National Transit Database. National Transit Database reports include total sources of revenue and complete expenditure reports for all public transportation operations, not just those funded by this project. Applicants partnering with a private operator should ensure that the private operator will meet all the comprehensive reporting requirements of the National Transit Database.

FTA is committed to making evidence-based decisions guided by the best available science and data. In accordance with the Foundations for Evidence-based Policymaking Act of 2018 (Pub. L. 115-435), FTA may use information submitted in discretionary funding applications; information in FTA's Transit Award Management System (TrAMS), including grant applications, Milestone Progress Reports (MPRs), Federal Financial Reports (FFRs); transit service, ridership and operational data submitted in FTA's National Transit Database; documentation and results of FTA oversight reviews, including triennial and State management reviews; and other publicly available sources of data to build evidence to support policy, budget, operational, regulatory, and management processes and decisions affecting FTA's grant programs.

As part of completing the annual certifications and assurances required of FTA grant recipients, a successful applicant must report on the suspension or debarment status of itself and its

principals. If the award recipient's active grants, cooperative agreements, and procurement contracts from all Federal awarding agencies exceeds \$10,000,000 for any period of time during the period of performance of an award made pursuant to this Notice, the recipient must comply with the Recipient Integrity and Performance Matters reporting requirements described in Appendix XII to 2 CFR part 200.

G. Federal Awarding Agency Contacts

For further information concerning this notice, please contact the FTAFerryPrograms@dot.gov, or Vanessa Williams, by phone at (202) 366-4818 or Sarah Clements at (202) 366-3062. A TDD is available for individuals who are deaf or hard of hearing at 800-877-8339. In addition, FTA will post answers to questions and requests for clarifications on FTA's website at <https://www.transit.dot.gov/grants/fta-ferry-programs>. To ensure receipt of accurate information about eligibility or the program, the applicant is encouraged to contact FTA directly, rather than through intermediaries or third parties. For issues with [GRANTS.GOV](https://www.grants.gov), please contact [GRANTS.GOV](https://www.grants.gov) by phone at 1-800-518-4726 or by email at support@grants.gov. Contact information for FTA's regional offices can be found on FTA's website at <https://www.transit.dot.gov/about/regional-offices/regional-offices>.

H. Other Information

This program is not subject to Executive Order 12372, "Intergovernmental Review of Federal Programs." FTA will consider applications for funding only from eligible recipients for eligible projects listed in section C.

Applications and supporting materials submitted to FTA may be subject to disclosure under Federal laws including, but not limited to, the Freedom of Information Act (FOIA). If a submission contains trade secret or confidential commercial or financial information, the submitter should segregate that information and clearly identify and mark each instance as "Confidential Business Information (CBI)" along with an explanation of its confidentiality. A general legend on the cover of an application, by itself, is insufficient marking. FTA will endeavor to protect confidential business information complying with these requirements to the extent required under law. If FTA receives a FOIA request for confidential business information, FTA will follow the procedures in DOT's FOIA regulation at

49 CFR 7.29. Only information that is segregated and marked in accordance with this section will be considered for exemption under FOIA because of its business confidentiality.

Nuria I. Fernandez,
Administrator.

[FR Doc. 2023–10551 Filed 5–17–23; 8:45 am]

BILLING CODE 4910–57–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0111]

Agency Information Collection Activity: Statement of Purchaser or Owner Assuming Seller's Loan

AGENCY: Veterans Benefits Administration; Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) of 1995, this notice announces that the Veteran Benefits Administration, Department of Veterans Affairs, will submit the collection of information abstracted below to the Office of Management and Budget (OMB) for review and comment. The PRA submission describes the nature of the information collection and its expected cost and burden and it includes the actual data collection instrument.

DATES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice by clicking on the following link www.reginfo.gov/public/do/PRAMain, select “Currently under Review—Open for Public Comments”, then search the list for the information collection by title or “OMB Control No. 2900–0111.”

FOR FURTHER INFORMATION CONTACT: Maribel Aponte, Office of Enterprise and Integration, Data Governance Analytics (008), 810 Vermont Ave. NW, Washington, DC 20420, (202) 266–4688 or email maribel.aponte@va.gov. Please refer to “OMB Control No. 2900–0111” in any correspondence.

SUPPLEMENTARY INFORMATION:

Authority: Public Law 104–13; 44 U.S.C. 3501–21.

Title: Statement of Purchaser or Owner Assuming Seller's Loan, VA Form 26–6382.

OMB Control Number: 2900–0111.

Type of Review: Extension of a currently approved collection.

Abstract: Under title 38, U.S.C., section 3702, authorizes collection of this information to help determine the release of liability and substitution of entitlement. 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.

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 **Federal Register** Notice with a 60-day comment period soliciting comments on this collection of information was published at insert citation date: 88 FR 16523 on March 17, 2023, page 16523.

Affected Public: Individuals or households.

Estimated Annual Burden: 250 hours.

Estimated Average Burden per

Respondent: 15 minutes.

Frequency of Response: One time.

Estimated Number of Respondents: 1,000.

By direction of the Secretary.

Maribel Aponte,

VA PRA Clearance Officer, Office of Enterprise and Integration, Data Governance Analytics, Department of Veterans Affairs.

[FR Doc. 2023–10597 Filed 5–17–23; 8:45 am]

BILLING CODE 8320–01–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0851]

Agency Information Collection Activity: Status of Loan Account— Foreclosure or Other Liquidation

AGENCY: Veterans Benefits Administration, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) of 1995, this notice announces that the Veterans Benefits Administration (VBA), Department of Veterans Affairs, will submit the collection of information abstracted below to the Office of Management and Budget (OMB) for review and comment. The PRA submission describes the nature of the information collection and its expected cost and burden and it includes the actual data collection instrument.

DATES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice by clicking on the following link www.reginfo.gov/public/do/PRAMain, select “Currently under Review—Open for Public Comments”, then search the list for the information collection by Title or “OMB Control No. 2900–0851.”

FOR FURTHER INFORMATION CONTACT: Maribel Aponte, Office of Enterprise and Integration, Data Governance Analytics (008), 810 Vermont Ave. NW, Washington, DC 20420, (202) 266–4688 or email maribel.aponte@va.gov. Please refer to “OMB Control No. 2900–0851” in any correspondence.

SUPPLEMENTARY INFORMATION:

Authority: Public Law 104–13; 44 U.S.C. 3501–3521.

Title: Status of Loan Account—Foreclosure or Other Liquidation, VA Form 26–0971.

OMB Control Number: 2900–0851.

Type of Review: Revision of a currently approved collection.

Abstract: VA Form 26–0971 is used when the holder of a delinquent vendee account is legally entitled to repurchase the loan by VA when the loan has been continuously in default for 3 months and the amount of the delinquency equals or exceeds the sum of 2 monthly installments.

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 **Federal Register** Notice with a 60-day comment period soliciting comments on this collection of information was published at 88 FR 15857 on March 14, 2023, pages 15857 and 15858.

Affected Public: Individuals or households.

Estimated Annual Burden: 5 hours.

Estimated Average Burden per

Respondent: 30 minutes.

Frequency of Response: One-time.

Estimated Number of Respondents: 10.

By direction of the Secretary.

Maribel Aponte,

VA PRA Clearance Officer, Office of Enterprise and Integration, Data Governance Analytics, Department of Veterans Affairs.

[FR Doc. 2023–10601 Filed 5–17–23; 8:45 am]

BILLING CODE 8320–01–P



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Part II

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA-HQ-OAR-2016-0243; FRL-5185.1-01-OAR]

RIN 2060-AV56

National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Plywood and Composite Wood Products (PCWP), as required by the Clean Air Act (CAA). To ensure that all emissions of hazardous air pollutants (HAP) from sources in the source category are regulated, the EPA is proposing HAP standards for processes currently unregulated for total HAP (including acetaldehyde, acrolein, formaldehyde, methanol, phenol, propionaldehyde), non-mercury (non-Hg) HAP metals, mercury (Hg), hydrogen chloride (HCl), polycyclic aromatic hydrocarbons (PAH), dioxin/furan (D/F), and methylene diphenyl diisocyanate (MDI). The standards the EPA is proposing include emission limitations and work practices applicable for PCWP process units and lumber kilns located at facilities that are major sources of HAP emissions. This proposal responds to the 2007 partial remand and vacatur of portions of the 2004 PCWP NESHAP in which the EPA previously concluded maximum achievable control technology was represented by no control (*i.e.*, no emissions reduction). This proposal also responds to or requests comment on issues raised in a petition for reconsideration the EPA received regarding the technology review and other amendments to the PCWP NESHAP the EPA finalized on August 13, 2020.

DATES: Comments must be received on or before July 3, 2023. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before June 20, 2023.

Public hearing: If anyone contacts us requesting a public hearing on or before May 23, 2023, we will hold a virtual public hearing. See **SUPPLEMENTARY**

INFORMATION for information on requesting and registering for a public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA-HQ-OAR-2016-0243, by any of the following methods:

- **Federal eRulemaking Portal:** <https://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-2016-0243 in the subject line of the message.
- **Fax:** (202) 566-9744. Attention Docket ID No. EPA-HQ-OAR-2016-0243.
- **Mail:** U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OAR-0216-0243, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- **Hand/Courier Delivery:** 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 detailed instructions on sending comments and additional information on the rulemaking process, see the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Katie Hanks, Sector Policies and Programs Division (E143-03), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-2159; and email address: hanks.katie@epa.gov.

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. To request a virtual public hearing, contact the public hearing team at (888) 372-8699 or by email at SPPDpublichearing@epa.gov. If requested, the hearing will be held via virtual platform on June 2, 2023. The hearing will convene at 10:00 a.m. Eastern Time (ET) and will conclude at 4:00 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. The EPA will announce further details at [https://www.epa.gov/stationary-sources-air-](https://www.epa.gov/stationary-sources-air-pollution/plywood-and-composite-wood-products-manufacture-national-emission)

[pollution/plywood-and-composite-wood-products-manufacture-national-emission](https://www.epa.gov/stationary-sources-air-pollution/plywood-and-composite-wood-products-manufacture-national-emission).

If a public hearing is requested, the EPA will begin pre-registering speakers for the hearing no later than 1 business day after a request has been received. To register to speak at the virtual hearing, please use the online registration form available at <https://www.epa.gov/stationary-sources-air-pollution/plywood-and-composite-wood-products-manufacture-national-emission> or contact the public hearing team at (888) 372-8699 or by email at SPPDpublichearing@epa.gov. The last day to pre-register to speak at the hearing will be May 30, 2023. Prior to the hearing, the EPA will post a general agenda that will list pre-registered speakers in approximate order at: <https://www.epa.gov/stationary-sources-air-pollution/plywood-and-composite-wood-products-manufacture-national-emission>.

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 4 minutes to provide oral testimony. The EPA encourages commenters to submit a copy of their oral testimony as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral testimony and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at <https://www.epa.gov/stationary-sources-air-pollution/plywood-and-composite-wood-products-manufacture-national-emission>. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact the public hearing team at (888) 372-8699 or by email at SPPDpublichearing@epa.gov to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by May 25, 2023. The EPA may not be able to arrange accommodations without advanced notice.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2016-0243. All documents in the docket are listed in <https://www.regulations.gov/>. Although listed, 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. With the exception of such material, publicly available docket materials are available electronically in *Regulations.gov*.

Instructions. Direct your comments to Docket ID No. EPA-HQ-OAR-2016-0243. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at <https://www.regulations.gov/>, including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit electronically to <https://www.regulations.gov/> any information that you consider to be CBI or other information whose disclosure is restricted by statute. This type of information should be submitted as discussed below.

The EPA may publish any comment received to its public docket. 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. The 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, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit <https://www.epa.gov/dockets/commenting-epa-dockets>.

The <https://www.regulations.gov/> website allows you to submit your comment anonymously, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through <https://www.regulations.gov/>, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in

the body of your comment and with any digital storage media you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at <https://www.epa.gov/dockets>.

Submitting CBI. Do not submit information containing CBI to the EPA through <https://www.regulations.gov/>. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, note the docket ID, mark the outside of the digital storage media as CBI, and identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* above. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI and note the docket ID. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2.

Our preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (e.g., Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the Office of Air Quality Planning and Standards (OAQPS) CBI Office at the email address oaqpscbi@epa.gov, and as described above, should include clear CBI markings and note the docket ID. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email oaqpscbi@epa.gov to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404-02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No.

EPA-HQ-OAR-2016-0243. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

Preamble acronyms and abbreviations. Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble.

While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACI activated carbon injection
 APCD air pollution control device
 BACT best available control technology
 BDL below detection level
 BF board feet
 BTF beyond-the-floor
 CAA Clean Air Act
 CBI Confidential Business Information
 CDK continuous dry kiln
 CEMS continuous emission monitoring system
 CFR Code of Federal Regulations
 Cl₂ chlorine
 CO_{2e} carbon dioxide equivalent
 D/F dioxin/furan (i.e., polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans)
 DLL Detection Level Limited
 dscm dry standard cubic meter
 EJ environmental justice
 EPA Environmental Protection Agency
 ERT Electronic Reporting Tool
 FR Federal Register
 gr/dscf grains per dry standard cubic foot
 HAP hazardous air pollutant(s)
 HCl hydrogen chloride
 HF hydrogen fluoride
 Hg mercury
 ICR information collection request
 kPa kilopascals
 lb/MSF ³/₄" pounds of pollutant per thousand square feet of ³/₄-inch thick board
 lb/MSF ³/₈" pounds of pollutant per thousand square feet of ³/₈-inch thick board
 lb/ODT pounds of pollutant per oven-dried ton of wood
 LVL laminated veneer lumber
 MACT maximum achievable control technology
 MBF thousand board feet
 MDF medium density fiberboard
 MDI methylene diphenyl diisocyanate
 MDL method detection limit
 mg/dscm milligrams of pollutant per dry standard cubic meter of air
 NAICS North American Industry Classification System
 NESHAP national emission standards for hazardous air pollutants
 NIST National Institute of Standards and Technology
 Non-Hg non-mercury
 NRDC Natural Resources Defense Council
 NSPS new source performance standards
 NTTAA National Technology Transfer and Advancement Act
 O&M operation and maintenance
 OAQPS Office of Air Quality Planning and Standards

OMB Office of Management and Budget
 OSB oriented strandboard
 PAH polycyclic aromatic hydrocarbons
 PBCO production-based compliance option
 PCWP plywood and composite wood products
 PDF portable document format
 PM particulate matter
 PRA Paperwork Reduction Act
 psia pounds per square inch absolute
 RCO regenerative catalytic oxidizer
 RDL representative detection limit
 RFA Regulatory Flexibility Act
 RMH resinated material handling
 RTO regenerative thermal oxidizer
 RTR residual risk and technology review
 SBA Small Business Administration
 SSM startup, shutdown, and malfunction
 TEQ toxic equivalency
 THC total hydrocarbon
 tpy tons per year
 ug/dscm micrograms of pollutant per dry standard cubic meter
 UL upper limit
 UMRA Unfunded Mandates Reform Act
 UPL upper prediction limit
 VCS voluntary consensus standards
 WESP wet electrostatic precipitator

Organization of this document. The information in this preamble is organized as follows:

I. General Information

- A. Does this action apply to me?
- B. Where can I get a copy of this document and other related information?

II. Background

- A. What is the statutory authority for this action?
- B. What is this source category and how does the current NESHAP regulate its HAP emissions?
- C. What data collection activities were conducted to support this action?

III. Analytical Procedures and Decision Making

IV. Analytical Results and Proposed Decisions

- A. What MACT standards are we proposing for direct-fired PCWP dryers?
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- C. What MACT standards are we proposing for process units with organic HAP emissions?
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- E. What performance testing, monitoring, and recordkeeping and reporting are we proposing?
- F. What other actions are we proposing, and what is the rationale for those actions?
- G. What compliance dates are we proposing, and what is the rationale for the proposed compliance dates?

V. Summary of Cost, Environmental, and Economic Impacts

- A. What are the affected sources?
- B. What are the air quality impacts?
- C. What are the cost impacts?
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VI. Request for Comments

VII. Submitting Data Corrections

VIII. Statutory and Executive Order Reviews

- A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
- B. Paperwork Reduction Act (PRA)
- C. Regulatory Flexibility Act (RFA)
- D. Unfunded Mandates Reform Act (UMRA)
- E. Executive Order 13132: Federalism
- F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
- G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
- H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
- I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR part 51
- J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

I. General Information

A. Does this action apply to me?

The source category that is the subject of this proposal is Plywood and Composite Wood Products regulated under 40 CFR part 63, subpart DDDD. The 2022 North American Industry Classification System (NAICS) codes for the Plywood and Composite Wood Products industry are 321113, 321211, 321212, 321215, 321219, and 321999. This list of categories and NAICS codes is not intended to be exhaustive but rather provides a guide for readers regarding the entities that this proposed action is likely to affect. The proposed standards, once promulgated, will be directly applicable to the affected sources. Federal, state, local, and tribal government entities would not be affected by this proposed action. As defined in the *Initial List of Categories of Sources Under Section 112(c)(1) of the Clean Air Act Amendments of 1990* (see 57 FR 31576, July 16, 1992) and *Documentation for Developing the Initial Source Category List, Final Report* (see EPA-450/3-91-030, July 1992), the Plywood and Particleboard source category is any facility engaged in the manufacturing of plywood and/or particle boards. This category includes, but is not limited to, manufacturing of chip waferboard, strandboard, waferboard, hardboard/cellulosic fiber board, oriented strandboard (OSB), hardboard plywood, medium density fiberboard (MDF), particleboard, softwood plywood, or other processes using wood and binder systems. The name of the source category was changed to Plywood and Composite

Wood Products (PCWP) on November 18, 1999 (64 FR 63025), to more accurately reflect the types of manufacturing facilities covered by the source category. In addition, when the EPA proposed the PCWP rule on January 9, 2003 (68 FR 1276), the scope of the source category was broadened to include lumber kilns located at stand-alone kiln-dried lumber manufacturing facilities or at any other type of facility.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action is available on the internet. Following signature by the EPA Administrator, the EPA will post a copy of this proposed action at <https://www.epa.gov/plywood-and-composite-wood-products-manufacture-national-emission>. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the proposal and key technical documents at this same website.

A redline/strikeout version of the rule showing the edits that would be necessary to incorporate the changes proposed in this action to 40 CFR part 63, subpart DDDD, is presented in the memorandum titled *Proposed Regulation Edits for 40 CFR part 63 Subpart DDDD National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products*, available in the docket for this action (Docket ID No. EPA-HQ-OAR-2016-0243).

II. Background

A. What is the statutory authority for this action?

The EPA originally promulgated the PCWP NESHAP (40 CFR part 63, subpart DDDD) on July 30, 2004. On August 13, 2020, the EPA took final action on the risk and technology review required by Clean Air Act (CAA) sections 112(d)(6) and (f)(2) for the PCWP residual risk and technology review (2020 RTR). The EPA is proposing in this action to amend the NESHAP to ensure that all emissions of HAP from sources in the source category are regulated.

In setting standards for major source categories under CAA section 112(d), the EPA has the obligation to address all HAP listed under CAA section 112(b) emitted by the source category. In the *Louisiana Environmental Action Network v. EPA (LEAN)* decision issued on April 21, 2020, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) held that the EPA

has an obligation to address unregulated emissions from a major source category when the Agency conducts the 8-year technology review of a maximum achievable control technology (MACT) standard that previously left such HAP emissions unregulated.

In 2007, the D.C. Circuit remanded and vacated portions of the 2004 NESHAP promulgated by the EPA to establish MACT standards for the PCWP source category. *NRDC v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007). In the 2004 NESHAP, the EPA had concluded that the MACT standards for several process units were represented by no emission reduction (or “no control” emission floors). The “no control” MACT conclusions were rejected because, as the court clarified in a related decision, the EPA must establish emission standards for listed HAP. 489 F.3d 1364, 1371, citing *Sierra Club v. EPA*, 479 F.3d 875 (D.C. Cir. 2007). The EPA acknowledged in the preamble to the proposed RTR (at 84 FR 47077–47078, September 6, 2019) that there are unregulated sources with “no control” MACT determinations in the PCWP source category, and we stated our plans to address those units in a separate action subsequent to the RTR.

This proposed rule responds to the partial remand and vacatur of the 2004 NESHAP, and to the petition for reconsideration of the 2020 technology review, and addresses currently unregulated emissions of HAP from process units in the PCWP source category, including lumber kilns. Six HAP compounds (acetaldehyde, acrolein, formaldehyde, methanol, phenol, propionaldehyde), defined as “total HAP” in the PCWP NESHAP, represent over 96 percent of the HAP emitted from the PCWP source category. In addition to total HAP, emissions estimates collected for the 2020 RTR indicated that unregulated HAP are present in the PCWP source category as a result of combustion in direct-fired dryers, including: non-mercury (non-Hg) HAP metals, mercury (Hg), hydrogen chloride (HCl), polycyclic aromatic hydrocarbons (PAH), dioxin/furan (D/F). There are also emissions of methylene diphenyl diisocyanate (MDI) from processes that use MDI resins and coatings. The EPA is proposing amendments establishing standards that reflect MACT for these pollutants emitted by process units that are part of the PCWP source category, pursuant to CAA sections 112(d)(2) and (3) and, where appropriate, CAA section 112(h).

B. What is this source category and how does the current NESHAP regulate its HAP emissions?

The PCWP industry consists of facilities engaged in the production of PCWP or kiln-dried lumber. Plywood and composite wood products are manufactured by bonding wood material (fibers, particles, strands, *etc.*) or agricultural fiber, generally with resin under heat and pressure, to form a structural panel or engineered wood product. Plywood and composite wood products manufacturing facilities also include facilities that manufacture dry veneer and lumber kilns located at any facility. Plywood and composite wood products include (but are not limited to) plywood, veneer, particleboard, OSB, hardboard, fiberboard, MDF, laminated strand lumber, laminated veneer lumber (LVL), wood I-joists, kiln-dried lumber, and glue-laminated beams. There are currently 223 major source facilities that are subject to the PCWP NESHAP, including 99 facilities manufacturing PCWP and 124 facilities producing kiln-dried lumber. A major source of HAP is a plant site that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more, or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year from all emission sources at the plant site.

The affected source under the PCWP NESHAP is the collection of dryers, refiners, blenders, formers, presses, board coolers, and other process units associated with the manufacturing of PCWP. The affected source includes, but is not limited to, green end operations, refining, drying operations (including any combustion unit exhaust stream routinely used to direct fire process unit(s)), resin preparation, blending and forming operations, pressing and board cooling operations, and miscellaneous finishing operations (such as sanding, sawing, patching, edge sealing, and other finishing operations not subject to other NESHAP). The affected source also includes onsite storage and preparation of raw materials used in the manufacture of PCWP, such as resins; onsite wastewater treatment operations specifically associated with PCWP manufacturing; and miscellaneous coating operations. The affected source includes lumber kilns at PCWP manufacturing facilities and at any other kind of facility.

The NESHAP contains several compliance options for process units subject to the standards: (1) installation and use of emissions control systems with an efficiency of at least 90 percent; (2) production-based limits that restrict

HAP emissions per unit of product produced; and (3) emissions averaging that allows control of emissions from a group of sources collectively (at existing affected sources). These compliance options apply for the following process units: fiberboard mat dryer heated zones (at new affected sources); green rotary dryers; hardboard ovens; press predryers (at new affected sources); pressurized refiners; primary tube dryers; secondary tube dryers; reconstituted wood product board coolers (at new affected sources); reconstituted wood product presses; softwood veneer dryer heated zones; rotary strand dryers; and conveyor strand dryers (zone one at existing affected sources, and zones one and two at new affected sources). In addition, the PCWP NESHAP includes work practice standards for dry rotary dryers, hardwood veneer dryers, softwood veneer dryers, veneer redryers, and group 1 miscellaneous coating operations (defined in 40 CFR 63.2292).

The 2020 residual risk review found that the risk associated with air emissions from the PCWP manufacturing industry (including lumber kilns) are acceptable and that the current PCWP NESHAP provides an ample margin of safety to protect public health. In the 2020 technology review, the EPA concluded that there were no developments in practices, processes, or control technologies that would warrant revisions to the standards promulgated in 2004. In addition to conclusions with respect to the RTR, the 2020 action contained amendments to remove exemptions from the standards during periods of startup, shutdown, and malfunction (SSM). The 2020 amendments added work practices so there would be standards in place of the former startup and shutdown exemptions for 3 specific events that occur during PCWP production: safety-related shutdowns, pressurized refiner startup/shutdown, and softwood veneer dryer gas-burner relights. Lastly, the 2020 amendments included provisions requiring electronic reporting and repeat emissions testing. However, the 2020 technology review did not address the unregulated HAP emissions from PCWP facilities that the EPA is now addressing in response to the 2007 remand of the 2004 NESHAP.

C. What data collection activities were conducted to support this action?

On October 5, 2017, the EPA issued an Information Collection Request (ICR) to gather information from PCWP manufacturers to support conducting the PCWP NESHAP RTR. The ICR gathered detailed process data, emission

release point characteristics, and HAP emissions data for PCWP process units located at major sources. The response rate for the 2017 ICR was over 99 percent. Following completion of the 2020 RTR, the EPA continued to track facility changes in the PCWP industry to stay abreast of the population of facilities subject to the PCWP NESHAP.

Using information from the 2017 ICR with more recent updates, as needed, the EPA assessed emissions test data needs to establish standards for unregulated HAPs. On February 28, 2022, the EPA requested emissions testing and other information in a CAA section 114 survey of 20 PCWP facilities operated by 9 companies. The purpose of the 2022 survey was to gather additional data to use along with the 2017 ICR data to establish emission standards for unregulated HAP. The EPA used information from both the 2017 ICR and 2022 survey to develop the standards proposed in this action. The data collected and used in this action are provided in the docket along with documentation of the analyses conducted.

III. Analytical Procedures and Decision Making

The MACT standards proposed in this action were developed pursuant to CAA section 112(d)(2) and (3) or, when appropriate, CAA section 112(h). When developing MACT standards, the “MACT floor” for existing sources is calculated based on the average performance of the best performing units in each category or subcategory and on a consideration of the variability of HAP emissions from these units. The MACT floor for new sources is based on the emissions levels that are achieved by the best performing similar source, with a similar consideration of variability. For existing sources, the MACT floor is based on the average emission limitation achieved by the best performing 12 percent of sources (for which the EPA has emissions information) for source categories or subcategories with 30 or more sources, or the average emission limitation achieved by the best performing 5 sources (for which the EPA has or could reasonably obtain emissions information) for categories or subcategories with fewer than 30 sources. To account for variability in PCWP manufacturing operations and resulting emissions, we calculated the MACT floors using the 99 percent Upper Prediction Limit (UPL) using available stack test data.¹ We note that

the MACT floors for certain existing and new units are based on limited data sets.²

The UPL approach addresses variability of emissions data from the best performing source or sources in setting MACT standards. The UPL also accounts for uncertainty associated with emission values in a dataset, which can be influenced by components such as the number of samples available for developing MACT standards and the number of samples that will be collected to assess compliance with the emission limit. The UPL approach has been used in many environmental science applications. As explained in more detail in the UPL Memo,³ the EPA uses the UPL approach to reasonably estimate the emissions performance of the best performing source or sources to establish MACT floor standards.

Once the UPL is calculated for a pollutant, the representative detection limit (RDL) for the pollutant measurement method is considered, if necessary. The RDL is representative of the laboratory instrument sensitivity and lowest industry-standard method detection limits (MDL) achieved when analyzing air pollutant samples. Consideration of the RDL is necessary when pollutants are measured near or below the detection limit of the analysis method, which was the case for some HAP measured in the 2022 survey. The EPA compares a value of 3 times the RDL (3xRDL)⁴ of the test method to UPL values to ensure that the calculated MACT floors account for measurement variability. If the 3xRDL value exceeds the MACT floor UPL, the 3xRDL value is substituted as the MACT floor emission limit to ensure that the standard is set no lower than the

MACT floors, see *Use of Upper Prediction Limit for Calculating MACT Floors* (UPL Memo), in the docket for this action.

² See the memorandum, *Approach for Applying the Upper Prediction Limit to Limited Datasets*, in the docket for this action.

³ See *Use of Upper Prediction Limit for Calculating MACT Floors* (UPL Memo), in the docket for this action.

⁴ The factor of 3 used in the 3xRDL calculation is based on a scientifically accepted definition of level of quantitation—simply stated, the level where a test method performs with acceptable precision. The level of quantitation has been defined as 10 times the standard deviation of 7 replicate analyses of a sample at a concentration level close to the MDL units of the emission standard. That level is then compared to the MACT floor value to ensure that the resulting emission limit is in a range that can be measured with reasonable precision. In other words, if the 3xRDL value were less than the calculated floor (e.g., calculated from the UPL), we would conclude that measurement variability has been adequately addressed; if it were greater than the calculated floor, we would adjust the emissions limit to comport with the 3xRDL value to address measurement variability.

minimum level at which emissions can reliably be measured. For the cases where we had low detection data, we reviewed the memorandum, *Data and procedure for handling below detection level data in analyzing various pollutant emissions databases for MACT and RTR emissions limits*, which describes the procedure for handling below detection level (BDL) data and developing RDL data when setting MACT emission limits.⁵

In addition, under CAA section 112(d)(2), the EPA must examine more stringent “beyond-the-floor” regulatory options to determine MACT. Unlike the floor minimum stringency requirements, the EPA must consider various impacts of the more stringent regulatory options in determining whether MACT standards are to reflect beyond-the-floor requirements. These impacts include the cost of achieving additional emissions reduction beyond that achieved by the MACT floor, any non-air quality health and environmental impacts that would result from imposing controls beyond the floor, and energy requirements of such beyond floor measures. If the EPA concludes that the more stringent regulatory options have unreasonable impacts, the EPA selects the MACT floor as MACT. However, if the EPA concludes that impacts associated with beyond-the-floor levels of control are reasonable in light of additional HAP emissions reductions achieved, the EPA selects those levels as MACT.

For some process types, it is not feasible to prescribe or enforce a numerical emission standard using the MACT floor and MACT determination approach described in CAA sections 112(d)(2) and (3). According to CAA section 112(h)(1), MACT standards may take the form of design, equipment, work practice, or operational standards if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard. To support a determination that it is not feasible to prescribe or enforce an emission standard, CAA sections 112(h)(2)(A) and (B) require the EPA to determine that either: (A) a HAP or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any federal, state or local law, or (B) the application of measurement methodology to a particular class of

¹ For more information regarding the general use of the UPL and why it is appropriate for calculating

⁵ Westlin/Merrill 2011. *Data and procedure for handling below detection level data in analyzing various pollutant emissions databases for MACT and RTR emissions limits*. December 13, 2011, in the docket for this action.

sources is not practicable due to technological and economic limitations.

IV. Analytical Results and Proposed Decisions

Section IV.A of this preamble discusses the standards the EPA is proposing for combustion-related HAP emissions (non-Hg metals, Hg, HCl, PAH, and D/F) from direct-fired PCWP dryers, including rotary strand dryers, green rotary dryers, dry rotary dryers, tube dryers, and softwood veneer dryers. Section IV.B discusses the standards we are proposing for all HAP from lumber kilns. Section IV.C discusses the total HAP standards we are proposing for various process units other than lumber kilns that also had “no control” MACT determinations in the 2004 NESHAP that were remanded and vacated. Section IV.D discusses the standards we are proposing for process units with MDI emissions, including reconstituted wood products presses, blow-line blend tube dryers, and miscellaneous coating operations.

A. What MACT standards are we proposing for direct-fired PCWP dryers?

1. Overview

Direct-fired dryer types. Direct-fired dryers are heated by the passing of combustion exhaust through the dryer such that the wood material being dried is contacted by the combustion exhaust. Direct-fired dryers emit combustion-related HAP because emissions from fuel burning pass through the dryer and the dryer’s air pollution control system. There are different designs of PCWP dryers defined in 40 CFR 63.2292 of the PCWP NESHAP, including the following types of direct-fired dryers: rotary strand dryers, green rotary dryers, dry rotary dryers, tube dryers, softwood veneer dryers (heated zones), fiberboard mat dryers (heated zones), and hardboard ovens. Most PCWP direct-fired dryers are fired with wood residuals or natural gas (or some combination of the 2 fuels). Wood residual fuels include bark, resin-free residuals, residuals containing resin (e.g., PCWP sander dust and trimmings) and mixtures of these wood fuels. Far less commonly for PCWP dryers, wood-derived syngas, propane, or fuel oil may be used.

In addition to the differences in fuel (e.g., wood residuals and natural gas) there are differences in drying system configurations. For example, direct-fired PCWP dryers can be designed with an individual natural gas or wood-fired suspension burner dedicated to a single dryer. Other configurations include a combustion unit providing heat to

multiple dryers. At some facilities, multiple combustion units are used to direct-fire one or more dryers. Based on a review of the design differences, 2 subcategories for setting MACT standards are being proposed for direct-fired PCWP dryers: (1) wood and other fuel-fired dryers; and (2) natural gas fuel-fired dryers. We are proposing these subcategories of PCWP dryers because combustion units firing wood residuals have different design and combustion-related HAP emissions profiles from those firing natural gas (or propane). Based on emission estimates collected with the 2017 ICR, emissions of non-Hg HAP metals, Hg, inorganic gaseous HAPs (HCl, hydrogen fluoride (HF), and chlorine (Cl₂)), D/F, and PAH in the PCWP source category are predominantly associated with wood residual combustion in direct wood-fired dryers. Subcategorization by fuel type is consistent with other NESHAPs, including the major source boiler NESHAP at 40 CFR part 63, subpart DDDDD (the Boiler MACT), where EPA subcategorized based on the primary fuel combusted in the process and the resulting differences in HAP emissions.⁶ We are proposing to add the following definitions to the PCWP NESHAP to support subcategorization of direct-fired PCWP dryers:

PCWP dryer means each dry rotary dryer, green rotary dryer, tube dryer, rotary strand dryer, hardboard oven, or press predryer; or the heated zones from a softwood or hardwood veneer dryer, conveyor strand dryer, or fiberboard mat dryer.

Direct wood-fired PCWP dryer means a direct-fired PCWP dryer in which 10 percent or more of the direct-fired annual heat input results from combustion of wood-derived fuel such as bark, wood residuals, or wood-derived syngas or any other fuel except for natural gas (or propane).

Direct natural gas-fired PCWP dryer means a direct-fired PCWP dryer (including each dry rotary dryer, green rotary dryer, tube dryer, rotary strand dryer, hardboard oven, press predryer or heated zones from a softwood or hardwood veneer dryer, conveyor strand dryer, or fiberboard mat dryer) in which greater than 90 percent of the direct-fired annual heat input results from natural gas (or propane) combustion.

In addition, we are proposing the same definition of natural gas that is used in the Boiler MACT. Wood residuals are typically an onsite industrial byproduct instead of a purchased fuel. Further subcategorization based on the specific

type of wood fuel used is not recommended because it is common for wood-residual mixtures to be used. Wood-derived syngas is considered part of the wood and other fuel subcategory although it is not currently used to direct-fire PCWP dryers (other than lumber kilns, which are discussed in section IV.B of this preamble). All other fuel types (fuel oil, etc.) are uncommon in PCWP direct-fired dryers but were included with the “wood and other fuel” subcategory to ensure that all fuels are covered under the standards in the absence of emissions data specific to other fuels. We are not proposing further subcategorization based on combustion unit design because of the large number of combustion unit and dryer combinations that exist, because there would be few units in each subcategory for which separate standards at both existing and new sources would need to be developed.

Format of emission limits (units of measure). Each emission limit is proposed in 2 formats: (1) concentration; and (2) mass per production. Concentration units include grains per dry standard cubic foot (gr/dscf) for PM and milligrams per dry standard cubic meter (mg/dscm) for non-PM pollutants. The concentration units of measure are neutral to the type of process and are relevant regardless of whether processes of multiple types are co-controlled with PCWP dryers. Mass per production units are pounds per thousand square feet (lb/MSF) for softwood veneer dryers and pounds per oven dried ton (lb/ODT) for all other dryer types. Mass per time (e.g., pounds per hour) was not considered as an emission limit format because of the need to normalize emissions for the different process throughputs across facilities in the industry. Mass per production units such as lb/ODT or lb/MSF standardize mass emission rates, so they are applicable to dryers across multiple facilities and reflect MACT across a range of production rates. These units of measure are commonly used for PCWP emission factors.

Emission limits were developed in 2 formats to provide compliance options based on what is achieved by the best performing systems. The 2 formats proposed provide flexibility for the various process configurations subject to the limits and are also helpful because some dryers may not be readily equipped for oven-dried production rate measurements at the dryer.

Ranking dryer systems by performance level. Direct-fired PCWP dryers have numerous drying system configurations. The overall drying system includes the interconnected

⁶ 75 FR 32017, June 4, 2010.

combustion unit(s), dryer(s), and air pollution control devices (APCDs). Within any drying system there can be 1 or more combustion units, 1 or more dryers, and 1 or more APCDs of different types in series or parallel. Given the different combinations of dryers and APCDs, we evaluated each set of interconnected combustion units, dryers, and APCDs venting to the same emission point(s) as a single drying system for purposes of evaluating and ranking performance level. For example, 5 dryers venting to one HAP APCD are part of 1 drying system with the HAP emission limitation achieved determined at the outlet of the HAP APCD. By ranking each system, the outlet emission level for the system is considered in the MACT ranking 1 time for the entire system, not 5 times for each dryer in the system. The systems approach was used to ensure that the various equipment combinations from the best performing facilities are accounted for in establishing the MACT limits.

To determine the performance level of a dryer system, we took the average of all available lb/production test runs at the APCD outlet. For dryer system control configurations with multiple APCD outlets, we summed the lb/production numbers from each outlet stack to arrive at the total emissions performance level for the dryer system. Once the lb/production performance level for each dryer system was determined, the dryer systems were ranked to identify the best performing systems (*i.e.*, those with the lowest emissions).

There are fewer than 30 of each type of wood-fired dryer system. When there are fewer than 30 sources, the MACT floor for existing sources is the average emission limitation achieved by the best performing 5 sources (for which the Administrator has or could reasonably obtain emissions information), and the MACT floor for new sources is the emission control achieved in practice by the best controlled similar source. When evaluating MACT floors for the PCWP dryers, if we had performance data for more than 5 dryer systems, we used the 5 systems with the lowest lb/production performance levels for calculating the existing source MACT floor. We used the single best performing system with the lowest lb/production performance level to calculate the new source MACT floor. The MACT floors in terms of emissions concentration were based on the same dryer system rankings.

2. PM and Non-Hg Metals

The EPA is proposing filterable particulate matter (PM) standards as a

surrogate for non-Hg HAP metals from wood-fired PCWP dryers. Filterable PM is commonly used as a surrogate for HAP metals in particulate form including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium. Air pollution control devices that reduce PM also reduce non-Hg HAP metals in particulate form. Emissions testing for speciated HAP metals and PM from wood-fired PCWP dryers was conducted using EPA Method 29 as part of the 2022 CAA section 114 survey. The speciated HAP metals were found to be present in the wood-fired PCWP dryer exhaust at levels above the detection limit. The 2022 test data, along with PM data from prior test reports collected by EPA in the 2017 and 2022 PCWP CAA section 114 surveys, were used to develop the MACT floors discussed in this section of the preamble.

Rotary strand dryers. There are 27 direct wood-fired rotary strand dryer systems in the U.S. including 1 dryer system at a synthetic area source. Emissions data for PM are available for 13 direct wood-fired rotary strand dryer systems. Because there are fewer than 30 direct wood-fired rotary strand dryer systems, the UPL MACT floor calculations for existing sources were based on the 5 best performing systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the PM MACT floor for existing sources, based on the UPL, is 9.9E-02 lb/ODT or 3.6E-03 gr/dscf and the PM MACT floor for new sources, based on 3xRDL, is 2.8E-02 lb/ODT or 7.0E-04 gr/dscf. The 3xRDL value was substituted for the lb/ODT UPL in the new source MACT floor to ensure that the standards are established at the minimum level at which emissions can be measured reliably.

Most of the direct wood-fired rotary strand dryer systems at major sources in the U.S. already operate with PM and HAP control technology (*e.g.*, wet electrostatic precipitator followed by a regenerative thermal oxidizer, WESP/RTO). The use of WESPs for PM control upstream of HAP controls on PCWP rotary strand dryers is prevalent because of the high moisture exhaust stream and nature of the particulate originating from dryers (*e.g.*, sticky, flammable). Other PM controls such as baghouses are not well-suited for controlling PM from these sources. No options more stringent than the MACT floor for existing or new sources were identified.

Some existing sources are expected to need to upgrade their WESP to meet the existing source MACT floor. One rotary

strand dryer system with an ESP but no additional HAP control device was assumed to need to install a WESP to meet the PM MACT floor and an RTO to achieve the PAH MACT floor (discussed under rotary strand dryers in section IV.A.5 of this preamble). An estimated 0.32 tpy of non-Hg HAP metals would be reduced from existing sources.

Two new OSB facilities with direct wood-fired rotary stand dryer systems are projected to be constructed within the next 5 years. The PM MACT floor for new rotary strand dryer systems is achievable with a very well-performing WESP/RTO system. An estimated 0.073 tpy non-Hg HAP metals would be reduced from new sources.

Green rotary dryers. There are 7 direct wood-fired green rotary dryer systems in the PCWP source category. Emissions data for PM are available for 5 direct wood-fired green rotary dryer systems. Because there are fewer than 30 direct wood-fired green rotary dryer systems, the UPL MACT floor calculations for existing sources were based on all 5 systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PM MACT floor for existing direct wood-fired green rotary dryer systems is 2.2E-01 lb/ODT or 1.2E-02 gr/dscf and the PM MACT floor for new sources is 2.5E-02 lb/ODT or 1.2E-03 gr/dscf. The wood-fired green rotary dryer systems in the PCWP source category already operate with PM and HAP control technology (*e.g.*, WESP/RTO or equivalent). No options more stringent than the MACT floor for existing or new sources were identified. Zero HAP reduction is estimated because all existing and new direct wood-fired green rotary dryers are expected to meet their floors with baseline control.

Dry rotary dryers. There are 9 direct wood-fired dry rotary dryer systems in the PCWP source category. Emissions data for PM are available for 7 dry rotary dryer systems. Because there are fewer than 30 direct wood-fired dry rotary dryer systems, the UPL MACT floor calculations for existing sources were based on the 5 best performing systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PM MACT floor for existing direct wood-fired dry rotary dryer systems is 5.8E-01 lb/ODT or 3.4E-02 gr/dscf and the PM MACT floor for new sources is 2.9E-01 lb/ODT or 2.2E-02 gr/dscf. The MACT floor is based on the current level of PM control (*i.e.*, mechanical collection) in use for existing wood-fired dry rotary dryer systems. All of the existing wood-fired dry rotary dryer systems are expected to

meet the PM MACT floor. Therefore, the HAP reduction for the existing PM MACT floor is zero. No new direct wood-fired dry rotary dryers are projected in the next 5 years.

We considered a beyond-the-floor option to achieve further PM reduction from existing or new direct wood-fired dry rotary dryers through the use of a WESP. A WESP could be used alone or as part of a WESP/RTO system (as discussed in section IV.A.5 of this preamble as a beyond-the-floor measure for PAH emissions) to enable the dry rotary dryers to meet the same PM limits as required for green rotary dryers. In considering this beyond-the-floor option, we also considered costs, non-air quality health and environmental impacts, and energy requirements of potentially imposing it as a MACT requirement. Nationwide costs of the beyond-the-floor option for existing direct wood-fired dry rotary dryers are estimated to be a one-time capital cost of \$42 million, and annual costs of \$10 million per year to install and operate a WESP. Nationwide emission reductions are estimated to be 56 tpy of PM and 0.17 tpy of non-Hg HAP metals, for a cost effectiveness of \$181,000 per ton of PM reduced and \$61 million/ton of non-Hg HAP metals reduced. Nationwide use of a WESP to control wood-fired dry rotary dryer non-Hg metals would consume an estimated 23,000 megawatt-hours per year (MWhr/yr) of electricity (with associated secondary air emissions), generate 21 million gallons of wastewater per year, and produce 4,000 tons of solid waste of per year. After considering the costs, environmental, and energy impacts of the beyond-the-floor option, the EPA is proposing that the MACT floor represents MACT for PM (non-Hg metals) from direct wood-fired dry rotary dryers due to the high costs and unfavorable cost effectiveness of the more stringent option.

Tube dryers. There are 11 direct wood-fired primary tube dryer systems in the PCWP source category. Emissions data for PM are available for 6 direct wood-fired primary tube dryer systems, 2 of which have emissions from a secondary tube dryer venting into the primary tube dryer. Because there are fewer than 30 direct wood-fired tube dryer systems, the UPL MACT floor calculations for existing sources were based on the 5 best performing systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PM MACT floor for existing direct wood-fired tube dryer systems is $3.1\text{E}-01$ lb/ODT or $3.1\text{E}-03$ gr/dscf and the PM MACT floor for new sources is $2.0\text{E}-02$ lb/ODT or $1.3\text{E}-03$

gr/dscf. No options more stringent than the MACT floor for existing or new sources were identified because the primary tube dryer systems in the U.S. already operate with PM controls (WESP, baghouse, scrubber, etc.) and HAP control technology (RTO or biofilter). Zero HAP reduction is estimated because all existing and new direct wood-fired tube dryers are expected to meet their respective PM MACT floors with baseline control.

Softwood veneer dryer heated zones. There are 3 softwood veneer dryer systems with direct wood-fired heated zones in the PCWP source category. Emissions data for PM are available for one direct wood-fired softwood veneer dryer system. Since the UPL calculation for existing and new sources was based on data from one system, the UPL results for existing and new sources are the same. The PM MACT floor for existing and new direct wood-fired softwood veneer dryer systems is $7.2\text{E}-02$ lb/MSF 3/8" or $1.5\text{E}-02$ gr/dscf. We did not identify any options more stringent than the MACT floor for existing or new softwood veneer dryer systems. All existing direct wood-fired softwood veneer dryers are expected to meet the existing floor using the control technology already installed; therefore, the HAP reduction for the existing floor is zero. Nationwide HAP reductions of the proposed PM MACT floor for new sources were not estimated because no new direct wood-fired dry softwood veneer dryers are projected in the next 5 years.

3. Mercury (Hg)

Emissions testing for Hg from wood-fired PCWP dryers was conducted using EPA Method 29 as part of the 2022 CAA section 114 survey. The data from this testing was used to develop the MACT floors described in this section of the preamble. Method 29 collects multiple sample fractions that are combined to determine Hg emissions. All of the Hg test runs for PCWP dryers were detection level limited (DLL), meaning 1 or more sample fractions from each run contained no detectable Hg. For the purpose of setting MACT standards, the EPA considers DLL test runs to contain detectable emissions. The EPA is proposing Hg emission limits for direct wood-fired PCWP dryers because all of the Method 29 test runs had at least 1 sample fraction in which Hg was detected.

The baseline level of Hg control for PCWP rotary strand, green rotary, tube, and softwood veneer dryers is typically a PM and HAP control device in series (e.g., WESP/RTO or similar). For dry rotary dryers, the baseline level of

control is a mechanical collector (e.g., multiclone). Due to the low levels of Hg emissions from PCWP dryers, which were usually below 3xRDL of the measurement method, the minimum level at which emissions can reliably be measured, all PCWP dryers are expected to meet the Hg MACT floors for existing and new sources with the baseline level of control. No regulatory options more stringent than the Hg MACT floors for existing or new wood-fired PCWP dryers were identified.

Rotary strand dryers. Emissions data for Hg are available for 6 direct wood-fired rotary strand dryer systems. Because there are fewer than 30 direct wood-fired rotary strand dryer systems, the UPL MACT floor calculations for existing sources were based on the 5 best performing systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the Hg MACT floor for existing direct wood-fired rotary strand dryer systems is $1.6\text{E}-05$ lb/ODT or $8.4\text{E}-04$ mg/dscm, and the Hg MACT floor for new sources is $1.6\text{E}-05$ lb/ODT or $8.4\text{E}-04$ mg/dscm. The 3xRDL values were substituted for both UPLs in the existing and new source MACT floors to ensure the standards are established at the minimum level at which emissions can be measured reliably. No additional Hg reductions are estimated.

Green rotary dryers. Emissions data for Hg are available for 4 direct wood-fired green rotary dryer systems. Because there are fewer than 30 direct wood-fired green rotary dryer systems, the UPL MACT floor calculations for existing sources were based on all 4 systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the Hg MACT floor for existing direct wood-fired green rotary dryer systems, based on the UPL, is $1.3\text{E}-05$ lb/ODT or $1.1\text{E}-03$ mg/dscm, and the Hg MACT floor for new sources, based on 3xRDL, is $1.1\text{E}-05$ lb/ODT or $8.4\text{E}-04$ mg/dscm. The 3xRDL value was substituted for the UPL in the new source MACT floor to ensure that the standards are established at the minimum level at which emissions can be measured reliably. No additional Hg reductions are estimated.

Dry rotary dryers. Emissions data for Hg are available for 3 direct wood-fired dry rotary dryer systems. Because there are fewer than 30 direct wood-fired dry rotary dryer systems, the UPL MACT floor calculations for existing sources were based on all 3 systems. The UPL MACT floor calculation for new sources

was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the Hg MACT floor for existing and new direct wood-fired dry rotary dryer systems, based on 3xRDL, is 9.9E-06 lb/ODT or 8.4E-04 mg/dscm. The 3xRDL values were substituted for both UPLs in the existing and new source MACT floors to ensure that the standards are established at the minimum level at which emissions can be measured reliably. No additional Hg reductions are estimated.

Tube dryers. Emissions data for Hg are available for 5 direct wood-fired primary tube dryer systems, 1 of which has emissions from a secondary tube dryer venting into the primary tube dryer. Because there are fewer than 30 direct wood-fired tube dryer systems, the UPL MACT floor calculations for existing sources were based on all 5 systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the Hg MACT floor for existing direct wood-fired tube dryer systems is 2.7E-05 lb/ODT or 1.6E-03 mg/dscm, and the Hg MACT floor for new sources is 2.7E-05 lb/ODT or 8.4E-04 mg/dscm. The 3xRDL values were substituted for the lb/ODT UPLs in the existing and new source MACT floors and for the concentration UPL in the new source floor to ensure that the standards are established at the minimum level at which emissions can be measured reliably. No additional Hg reductions are estimated.

Softwood veneer dryers. Emissions data for Hg are available for 1 direct wood-fired softwood veneer dryer system. Because the UPL calculation for existing and new sources was based on data from one system, the UPL results for existing and new sources are the same. The Hg MACT floor for existing and new direct wood-fired softwood veneer dryer systems is 5.8E-05 lb/MSF 3/8" or 4.1E-02 mg/dscm. No additional Hg reductions are estimated.

4. Acid Gases

Emissions testing for HCl, HF, and Cl₂ from wood-fired PCWP dryers was conducted using EPA Method 26A as part of the 2022 CAA section 114 survey. Emissions of HF were below detection limit (BDL) in 99 percent of the EPA Method 26A test runs. Chlorine emissions were BDL in 65 percent of the test runs. Emissions of HCl were detected in 71 percent of the EPA Method 26A test runs. No acid gas emissions were detected from the wood-fired softwood veneer dryer tested, and

we are, therefore, not proposing acid gas standards for this subcategory. Based on the available data, we are proposing acid gas emission limits in terms of HCl emissions from direct wood-fired rotary strand dryers, green rotary dryers, dry rotary dryers, and tube dryers. The data from the 2022 emissions testing were used to develop the MACT floors discussed in this section of the preamble.

Rotary strand dryers. Emissions data for HCl are available for 6 direct wood-fired rotary strand dryer systems. Because there are fewer than 30 direct wood-fired rotary strand dryer systems, the UPL MACT floor calculations for existing sources were based on the 5 best performing systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the HCl MACT floor for existing direct wood-fired rotary strand dryer systems is 5.8E-03 lb/ODT or 1.5E-02 mg/dscm and the HCl MACT floor for new sources is 1.7E-03 lb/ODT or 1.0E-01 mg/dscm. The 3xRDL values were substituted for the UPLs in the new source MACT floor to ensure that the standards are established at the minimum level at which emissions can be measured reliably. No options more stringent than the MACT floor were identified for existing or new rotary strand dryers. Zero emissions reduction is estimated because all existing direct wood-fired dry rotary dryers are expected to meet the HCl MACT floor with current controls.

The HCl MACT floor for new wood-fired rotary strand dryers is about 10 percent lower than the average HCl emissions from rotary strand dryer systems included in the CAA section 114 tests. Although below the average performance level of dryers tested, the HCl MACT floor emission level (based on the UPL) has been achieved by 3 rotary strand dryers with WESP control and a rotary strand dryer with a multiclone. Thus, the new source MACT floor for rotary strand dryers is expected to be met with a well-performing WESP system. An example of a well-performing WESP is one that incorporates caustic addition (e.g., 1 percent) into the WESP recirculation water and has increased blowdown. The incremental HCl emission reduction estimated for new wood-fired rotary strand dryers using an upgraded WESP is 0.072 tpy.

Green rotary dryers. Emissions data for HCl are available for 4 direct wood-fired green rotary dryer systems. Because there are fewer than 30 direct wood-fired green rotary dryer systems,

the UPL MACT floor calculations for existing sources were based on all 4 systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the HCl MACT floor for existing direct wood-fired green rotary dryer systems is 6.5E-03 lb/ODT or 9.7E-01 mg/dscm, and the HCl MACT floor for new sources is 2.9E-03 lb/ODT or 1.0E-01 mg/dscm. The 3xRDL value was substituted for the concentration UPL in the new source MACT floor to ensure that the standards are established at the minimum level at which emissions can be measured reliably. No options more stringent than the MACT floor were identified for existing or new green rotary dryers, which are already well-controlled. Zero emissions reduction is estimated because all existing and new direct wood-fired green rotary dryers are expected to meet their respective HCl MACT floors with baseline controls.

Dry rotary dryers. Emissions data for HCl are available for 3 direct wood-fired dry rotary dryer systems. Because there are fewer than 30 direct wood-fired dry rotary dryer systems, the UPL MACT floor calculations for existing sources were based on all 3 systems. The UPL MACT floor calculation for new sources was based on the best performing system. After comparing the UPL calculations to the corresponding 3xRDL limits, the HCl MACT floor for existing and new direct wood-fired dry rotary dryer systems is 1.10E-03 lb/ODT or 1.0E-01 mg/dscm. The 3xRDL values were substituted for both UPLs in the existing and new source MACT floors to ensure that the standards are established at the minimum level at which emissions can be measured reliably. No options more stringent than the MACT floor were identified for existing or new dry rotary dryers because the MACT floors are based on 3xRDL (i.e., the minimum level at which emissions can reliably be measured). Zero emissions reduction is estimated because all existing direct wood-fired dry rotary dryers are expected to meet the existing HCl MACT floor. No new units are projected in the next 5 years.

Tube dryers. Emissions data for HCl are available for 5 direct wood-fired primary tube dryer systems, one of which has emissions from a secondary tube dryer venting into the primary tube dryer. Because there are fewer than 30 direct wood-fired tube dryer systems, the UPL MACT floor calculations for existing sources were based on all 5 systems. The UPL MACT floor calculation for new sources was based on the best performing system. After

comparing the UPL calculations to the corresponding 3xRDL limits, the HCl MACT floor for existing direct wood-fired tube dryer systems is $6.4\text{E}-03$ lb/ODT or $7.4\text{E}-01$ mg/dscm, and the HCl MACT floor for new sources is $2.3\text{E}-03$ lb/ODT or $1.0\text{E}-01$ mg/dscm. The 3xRDL values were substituted for the UPLs in the new source MACT floor to ensure that the standards are established at the minimum level at which emissions can be measured reliably.

Existing and new wood-fired tube dryer systems are expected to meet the HCl MACT floors with the baseline controls, which typically incorporate a WESP or scrubber. No options more stringent than the existing and new source MACT floors were identified for primary tube dryers. All existing and new direct wood-fired tube dryers are expected to meet their HCl MACT floors; therefore, the HAP reduction for both floors is zero.

5. PAH

The EPA is proposing emission limits for PAH emissions that were detected in the exhaust from wood-fired rotary strand dryers, green rotary dryers, dry rotary dryers, and tube dryers. Emissions testing for PAH from wood-fired PCWP dryers was conducted using EPA Other Test Method 46 (OTM-46) as part of the 2022 CAA section 114 survey. EPA OTM-46 is nearly identical to the updated EPA Method 23, for which revisions were promulgated on March 20, 2023 (88 FR 16732). The data from the 2022 testing was used to develop the MACT floors discussed in this section of the preamble. The PAH MACT floors discussed here for wood-fired rotary strand dryers, green rotary dryers, dry rotary dryers, and tube dryers are greater than the corresponding 3xRDL values for PAH. For softwood veneer dryers, the 3xRDL value for PAH is proposed as MACT.

Rotary strand dryers. Emissions data for PAH are available for 6 direct wood-fired rotary strand dryer systems. Because there are fewer than 30 direct wood-fired rotary strand dryer systems, the UPL MACT floor calculations for existing sources were based on the 5 best performing systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PAH MACT floor for existing direct wood-fired rotary strand dryer systems is $3.1\text{E}-04$ lb/ODT or $2.7\text{E}-02$ mg/dscm, and the PAH MACT floor for new sources is $3.9\text{E}-05$ lb/ODT or $1.4\text{E}-03$ mg/dscm. The PAH MACT floors are based on dryers that already have PM and HAP controls in series. Therefore, no options more stringent

than the MACT floors were identified for existing or new sources.

Most existing wood-fired rotary strand dryer systems are expected to meet the PAH MACT floor with baseline PM and HAP controls in series. One rotary strand dryer system with an ESP but no additional HAP control device was assumed to need to add a WESP to meet the PM MACT floor and an RTO to achieve the PAH MACT floor. Nationwide emission reductions of the proposed MACT floor for PAH for existing direct wood-fired rotary strand dryers are estimated to be 0.043 tpy of PAH reduced and 130 tpy of VOC reduced.

New wood-fired rotary strand dryer systems are expected to be challenged to meet the stringent new source PAH MACT floor in spite of coming online with a WESP/RTO control system. While the new source MACT floor emission level based on the UPL has been achieved by rotary strand dryers with multiclone/RTO and WESP/RTO controls, the new source PAH MACT floor is 90 percent lower than the average PAH performance level achieved by the well-controlled rotary strand dryers in the CAA section 114 emission tests. The burner tune-up requirements required for all direct-fired PCWP dryers are expected to help with meeting the PAH MACT floor. Nationwide, 0.15 tpy of PAH reductions are estimated to be associated with the proposed PAH MACT floor.

Green rotary dryers. Emissions data for PAH are available for 4 direct wood-fired green rotary dryer systems. Because there are fewer than 30 direct wood-fired green rotary dryer systems, the UPL MACT floor calculations for existing sources were based on all 4 systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PAH MACT floor for existing direct wood-fired green rotary dryer systems is $9.0\text{E}-03$ lb/ODT or $4.1\text{E}-01$ mg/dscm, and the PAH MACT floor for new sources is $2.6\text{E}-05$ lb/ODT or $4.4\text{E}-03$ mg/dscm. The PAH MACT floors are based on dryers that already have PM and organic HAP controls in series. Therefore, no options more stringent than the MACT floors were identified for existing or new sources. No reductions in PAH were estimated because existing wood-fired green rotary dryer systems are expected to meet the PAH MACT floor with baseline HAP controls. The burner tune-up requirements required for all direct-fired PCWP dryers are expected to help with meeting the PAH MACT floor. No options more stringent than the MACT floor were identified for new sources. No reductions in PAH are

estimated because new direct wood-fired green rotary dryers are expected to meet the MACT floor with proper tuning.

Dry rotary dryers. Emissions data for PAH are available for 3 direct wood-fired dry rotary dryer systems. Because there are fewer than 30 direct wood-fired dry rotary dryer systems, the UPL MACT floor calculations for existing sources were based on all 3 systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PAH MACT floor for existing direct wood-fired dry rotary dryer systems is $4.3\text{E}-04$ lb/ODT or $3.9\text{E}-02$ mg/dscm, and the PAH MACT floor for new sources is $2.5\text{E}-05$ lb/ODT or $2.2\text{E}-03$ mg/dscm.

All existing direct wood-fired dry rotary dryers are expected to meet the existing PAH MACT floor with the baseline controls (mechanical collection); therefore, the HAP reduction for the existing floor is zero. No new direct wood-fired dry rotary dryers are projected in the next 5 years. If a new wood-fired dry rotary dryer were to be installed, it is estimated that some facilities may need an RTO to meet the new source PAH MACT floor.

We considered a beyond-the-floor option for existing and new wood-fired dry rotary dryers to use a HAP control system that meets the limits in table 1B to subpart DDDD of 40 CFR part 63, which we anticipate would be based on use of a WESP/RTO system. The WESP would protect the RTO from particulate build up and is a beyond-the-floor option for PM for dry rotary dryers. The costs and other impacts of using a WESP on wood-fired dry rotary dryers were discussed in section IV.A.2 of this preamble. Nationwide costs of the beyond-the-floor option to reduce PAH from existing direct wood-fired dry rotary dryers using an RTO are estimated to be a one-time capital cost of \$16 million and annual cost of \$6.8 million per year. Nationwide HAP and VOC reductions for existing sources are estimated to be 18 tpy of organic HAP (including 0.016 tpy of PAH) and 282 tpy of VOC for a cost effectiveness of \$383,000/ton of organic HAP reduced, \$431 million/ton of PAH reduced, and \$24,000/ton of VOC reduced. Nationwide energy impacts are estimated to be consumption of 23,000 MWhr/yr of electricity, with associated secondary air emissions, and 371,000 MMBtu/yr of natural gas. Nationwide wastewater (e.g., for RTO washouts) and solid waste impacts are estimated to be 273,000 gallons of wastewater per year and 84 tons of solid waste of per year. Nationwide costs and impacts of the beyond-the-floor option for PAH for

new direct wood-fired dry rotary dryers were not estimated as no new direct wood-fired dry rotary dryers are projected in the next 5 years.

After considering the costs, non-air quality environmental, and energy impacts of the beyond-the-floor option for PAH, we are proposing that MACT is represented by the PAH MACT floor. We rejected the more stringent beyond-the-floor option based on use of a WESP/RTO system because of its high costs, unfavorable cost effectiveness, energy usage, and non-air-quality environmental impacts.

Tube dryers. Emissions data for PAH are available for 5 direct wood-fired primary tube dryer systems, one of which has emissions from a secondary tube dryer venting into the primary tube dryer. Because there are fewer than 30 direct wood-fired tube dryer systems, the UPL MACT floor calculations for existing sources were based on all 5 systems. The UPL MACT floor calculation for new sources was based on the best performing system. The PAH MACT floor for existing direct wood-fired tube dryer systems is $3.0\text{E-}04$ lb/ODT or $3.3\text{E-}03$ mg/dscm, and the PAH MACT floor for new sources is $1.2\text{E-}05$ lb/ODT or $6.3\text{E-}04$ mg/dscm. The PAH MACT floors are based on tube dryer systems that already have PM and HAP controls in series. Therefore, no options more stringent than the MACT floors were identified for existing or new primary tube dryers. Because all existing and new direct wood-fired tube dryers are expected to meet their MACT floors for PAH with baseline HAP controls, zero HAP reduction is estimated.

Softwood veneer dryers. There are 3 softwood veneer dryer systems with direct wood-fired heated zones in the PCWP source category. Detectable PAH emissions are not expected from these dryers. Direct-wood fired softwood veneer dryers were not included in the CAA section 114 testing using EPA OTM-46 because veneer dryers operate at lower temperature with less mixing than rotary and tube dryers and, therefore, are not expected to have the same potential for formation of detectable PAH emissions as direct wood-fired rotary and tube dryers, which operate at higher temperatures under more turbulent conditions. However, given that PAH emissions were measured in the exhaust from other wood-fired PCWP dryers, absent PAH test data, we are proposing a PAH limit of $3.3\text{E-}05$ mg/dscm based on 3xRDL for existing and new direct wood-fired softwood veneer dryers. We anticipate that this limit would be met through the same burner tune-up

standards proposed to be required for all wood-fired dryers as well as using the incineration-based controls already in place on the softwood veneer dryers. Thus, no emission reductions are estimated, and no options more stringent than the 3xRDL value were identified for existing or new wood-fired softwood veneer dryers. The EPA requests submittal of available PAH emissions information for wood-fired softwood veneer dryers to help inform the final rule.

6. Burner Tune-Up Standards

The EPA is proposing burner tune-up standards to address dioxin/furan (D/F) from wood and other fuel fired dryers, any combustion-related HAP that may be emitted from natural-gas fired PCWP dryers, and any HAP from combustion unit bypass stacks. As discussed in section IV.B of this preamble, burner tune-ups are also being proposed as a standard for direct-fired lumber kilns to address combustion-related HAP from direct fuel firing and kiln combustion unit bypass stacks.

a. D/F From Wood-Fired PCWP Dryers

Emissions testing for D/F from wood-fired PCWP dryers was conducted using EPA OTM-46 as part of the 2022 CAA section 114 survey. The EPA conducted a detection limit evaluation on the D/F emissions test runs gathered from the 2022 CAA section 114 requests for wood-fired PCWP dryers. Over 70 percent of the D/F congener test runs were BDL. When considered on a toxic equivalency (TEQ) basis, 89 percent of test runs were below the 3xRDL value for TEQ. The EPA considers a work practice to be justified if a significant majority of emissions data available indicate that emissions are so low that they cannot be reliably measured (e.g., more than 55 percent of test runs are non-detect).⁷ Therefore, a work practice standard is being proposed for D/F from wood-fired PCWP dryers. The proposed work practice for existing and new PCWP dryers is an annual tune-up of the burners that provide direct heat to PCWP wood-fired dryers in order to ensure good combustion and, therefore, minimize emissions of organic HAP.

Nationwide HAP reductions of the proposed work practice for D/F for existing direct wood-fired PCWP dryers are estimated to be 5.9 tpy of all HAP reduced (including $2.43\text{E-}06$ tpy of D/F). Nationwide HAP reductions of the

proposed work practice for D/F for new and reconstructed direct wood-fired PCWP dryers are estimated to be 0.20 tpy of HAP reduced (including $1.34\text{E-}07$ tpy of D/F).

b. Natural-Gas Fired PCWP Dryers

Combustion-related HAP emissions from combustion units burning natural gas to directly fire PCWP dryers are similar to emissions from boilers and process heaters that burn natural gas. Under the Boiler MACT, "units designed to burn gas 1 fuels" (i.e., units burning natural gas) were required to conduct periodic tune-ups as part of a work practice for non-Hg HAP metals, Hg, acid gases, D/F, and organic HAP. As explained at 76 FR 15637–38 (March 21, 2011), measured emissions of these pollutants from natural gas-fired boilers and process heaters were routinely found to be below the detection limits of EPA test methods, and, as such, the EPA found it technically and economically impracticable to reliably measure emissions from these units. The combustion unit tune-up work practice was identified as an effective HAP emissions standard for natural gas-fired PCWP dryers that combust the cleanest fuels available. Based on that conclusion, we are proposing a burner tune-up work practice standard for combustion-related HAP, including non-Hg metals, Hg, acid gases, D/F, and PAH, from existing and new direct natural gas-fired PCWP dryers. In addition to the proposed burner tune-up work practice standard for combustion-related HAP from direct gas-fired PCWP dryers, the current emission standards for PCWP dryers (40 CFR 63.2240(b)) already limit organic HAP emissions, including organic HAP emitted from natural gas combustion and organic HAP from the drying process. Nationwide combustion HAP reductions of the proposed tune-up work practice standard are estimated to be 0.10 tpy for existing sources and 0.0073 tpy for new sources.

c. Combustion Unit Bypass Stacks

Combustion-related HAP emissions can be emitted for brief periods of time from bypass stacks located between a combustion unit and PCWP dryer (or lumber kiln) direct-fired by the combustion unit when the dryer (or kiln) is unable to accept the hot exhaust from the direct-firing combustion unit. It is not feasible to prescribe numeric emission standards for combustion-related HAP emissions briefly emitted from bypass stacks between the combustion unit and dryer (or lumber kiln). Emissions measurement methodologies, including stack tests

⁷ See the June 5, 2014, memorandum, *Determination of 'non-detect' from EPA Method 29 (multi-metals) and EPA Method 23 (dioxin/furan) test data when evaluating the setting of MACT floors versus establishing work practice standards*, in the docket for this action.

which require hours to complete, are not feasible for PCWP combustion unit bypasses that last minutes at a time. Use of a continuous emission monitoring system (CEMS) to capture these events is not feasible due to calibration issues and the need to perform relative accuracy test audits (RATA), which involve stack tests. Establishing parameter limits correlated with emissions also is not feasible because this would be done through stack testing. Therefore, we are proposing a work practice standard for existing and new combustion bypass stacks associated with direct-fired PCWP dryers or direct-fired lumber kilns regardless of fuel type. The work practice standard would require an annual tune-up of the burner associated with the bypass stack, along with monitoring and reporting bypass stack usage. Bypass stack usage time would be monitored using an indicator such as bypass damper position or temperature in the bypass stack. No feasible options more stringent than burner tune-ups coupled with bypass stack usage monitoring were identified for existing or new combustion bypass stacks. No HAP reductions were estimated in conjunction with bypass stack monitoring.

B. What MACT standards are we proposing for lumber kilns?

The EPA is proposing standards to limit emissions of all HAP from lumber kilns. All HAP emissions would be limited by the work practices the EPA is proposing that would limit over-drying of lumber. Combustion-related HAP emissions from direct-fired kilns would be further limited by the proposed burner tune-up standards. Additional information on our review of information pertaining to lumber kilns is available in the memorandum, *Development of National Emission Standards for Hazardous Air Pollutant Emission Standards for Lumber Drying Kilns*, in the docket for this action.

1. Lumber Kiln Overview

Lumber kilns can be characterized by wood type (softwood or hardwood), design (batch or continuous), and heating method (indirect- or direct-fired). Although few hardwood lumber kilns are located at major sources, we are proposing to include both hardwood and softwood lumber kilns in the PCWP NESHAP so HAP standards would apply to any lumber kiln located at a PCWP or lumber facility that is a major source of HAP emissions.

In batch kilns, lumber is loaded into the kiln where it remains stationary during the entire drying cycle. When

drying is complete, the batch kiln is shut down to remove the lumber. The kiln is restarted again after it is loaded with a new batch of lumber. Batch kilns can be either track-loaded, where multiple packages⁸ of lumber are pushed into the kiln on tracks at once, or smaller package loaded kilns, where lumber packages are loaded in the batch kiln with a forklift. The track loaded kilns tend to have higher annual throughput and are the type of batch kilns most commonly used at major source PCWP facilities.

Batch kilns typically have numerous roof vents positioned in rows down each side of the kiln's roof. The vents open and close throughout the drying cycle as the temperature and humidity in the kiln change. Internal fans under the kiln roof circulate air around the packages of lumber. The fans change direction every 2 to 3 hours to provide even drying of the lumber. Consequently, one bank of roof vents is normally exhausting hot, moist air while the other row of vents is allowing ambient air into the kiln. The direction of flow cycles between air intake and exhaust throughout the drying cycle. Batch kilns release fugitive air emissions from doors or cracks in the kiln exterior due to pressure differences between the interior of the kiln and ambient conditions outside the kiln.

Over the past decade, continuous dry kilns (CDKs) have become popular for drying southern pine lumber in the U.S. Southeast. Unlike batch kilns, CDKs do not have to be shut down for loading and unloading. In CDKs, lumber travels continuously through the kiln on tracks. Most CDKs in the U.S. have a "counter-flow" design where 2 sets of lumber travel in opposite directions to one another such that on one end of the kiln green lumber enters the kiln parallel to dry lumber exiting the kiln. This design allows heat from the dried lumber coming out of the kiln to preheat the incoming green lumber to conserve energy. There are no doors on CDKs, allowing the constant flow of lumber into and out of each end of the kiln. Thus, CDKs release exhaust containing steam and fugitive emissions from their open ends. Some CDKs have powered or unpowered hoods or stacks over their openings to direct a portion (e.g., 40 to 80 percent of the volume) of exhaust upward while the remaining exhaust exits through the kiln ends.

In addition to batch or continuous design, another key design feature of

⁸ Packages are stacks of boards layered with small strips of wood called "stickers" to allow for air to circulate around the boards while the boards are drying in the kiln.

lumber kilns is their heating method. Indirect-fired kilns are heated with steam from a boiler. The steam circulates through coils in the path of air circulation within the kiln. Direct-fired kilns use hot gases from fuel combustion to heat the kiln such that the kiln exhaust contains emissions from wood drying and fuel combustion. Combustion units used to direct-fire kilns may be a dedicated burner for each kiln or a combustion unit that direct-fires multiple kilns. Fuels used to direct-fire kilns include natural gas, wood, or wood-derived syngas generated in a gasifier. Wood is often used for direct-fired lumber kilns because it is a readily available byproduct of lumber manufacturing and is typically generated onsite. Gasifiers typically use green sawdust generated from cutting logs into boards. The green sawdust is first gasified under sub-stoichiometric conditions to produce a syngas that is then burned in a secondary combustion chamber to directly fire the kiln. Regardless of fuel, combustion gases are usually too hot for direct introduction into the kiln, so they are diluted with recirculated kiln exhaust and ambient air in a blend box prior to introduction to the kiln.

The EPA has identified 680 lumber kilns at major source PCWP facilities subject to 40 CFR part 63, subpart DDDD, including:

- 11 batch, indirect-fired, hardwood kilns.
- 203 batch, indirect-fired, southern yellow pine (SYP) kilns.
- 241 batch, indirect-fired, other (e.g., western) softwood kilns.
- 103 batch, direct-fired, SYP kilns.
- 98 continuous, direct-fired, SYP kilns.
- 24 continuous, indirect-fired, SYP kilns.

None of the lumber kilns identified operate with any add-on air pollution controls. Emission factors that have been adopted by regulatory agencies and lumber producers for emission estimation purposes were mostly derived from small-scale kiln tests and a few (often research-level) tests of full-scale kilns. This information is useful for estimating emissions for inventory reporting purposes but is not suitable for developing or enforcing national emission standards due to the impracticality of capturing and measuring lumber kiln emissions (discussed in more detail later in this preamble). A significant challenge to measuring batch and continuous lumber kiln emissions is accurate determination of the total lumber kiln gas flow rate and the need to extrapolate concentrations from 1 or 2 sampling locations to

estimate total kiln emissions from several emission points (including fugitives).

Because of the infeasibility of lumber kiln emissions collection and control, and because of measurement challenges, many facilities and permit authorities have established work practices for limiting organic emissions from lumber kilns. Good design and operating practices were determined to be the best available control technology (BACT) for several lumber kilns. A review of BACT determinations for new and modified kilns is relevant because a work practice can be found as BACT only after a permitting authority finds that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make use of a numerical emission standard infeasible.⁹ This finding is similar to the requirements under CAA section 112(h) for concluding that MACT is represented by a work practice or operational standard.

2. Rationale for Work Practices

Given the impracticability of capturing and measuring emissions from lumber kilns, we have concluded that the criteria in CAA section 112(h) for establishing a design, equipment, work practice, or operational standard apply for lumber kilns. CAA section 112(h) states that if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a HAP, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof, which in the Administrator's judgment is consistent with the provisions of CAA section 112(d). The phrase "not feasible to prescribe or enforce an emission standard" is further defined in CAA section 112(h)(2)(A) and (B) as any situation in which the Administrator determines that: (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or (B) the application of

measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

Relative to CAA section 112(h)(2)(A), the total volume of lumber kiln emissions cannot be emitted through a conveyance that is designed and constructed to emit or capture HAP emissions. For example, batch kilns have numerous vents that cycle between air intake and exhaust in addition to some fugitive emissions that can be emitted from the kiln doors or walls. Batch kilns do not and cannot have conveyances to capture emissions from the exhaust vents or eliminate the air intake, as such conveyances would disrupt the drying process by limiting air flow into the kiln. If constructed, flow exiting a conveyance would be intermittent (cyclical) just as it is from each kiln vent, meaning a conveyance would not help with measuring emissions as needed to prescribe or enforce a numeric emission standard. Similarly, CDKs have considerable amounts of fugitive emissions from their openings that cannot be eliminated while allowing for lumber to enter and exit the kiln. While some CDKs have passive hoods or stacks (which may be powered or unpowered) at their ends to direct a fraction of the kiln exhaust upward to improve dispersion, these devices do not and cannot eliminate the fugitive emissions from the CDK openings. If powered stacks were added to draw more air out of the CDK in an attempt to eliminate the fugitives to obtain a reliable emissions measurement, the energy-transfer function of the CDK, in which heat and steam from the exiting lumber are used to precondition incoming lumber, would be lost. Thus, it is not possible to capture emissions from the openings at each end or directly measure the total gas flow rate from a CDK as needed to prescribe or enforce an emission limit.

Relative to CAA section 112(h)(2)(B), there are technological and economic limitations to applying a measurement methodology for lumber kilns as needed to prescribe or enforce a numeric emission standard. For batch kilns, with numerous vents cycling between air intake and exhaust, and temperature and humidity changes throughout the batch cycle, there is not a consistent flow rate or concentration to measure using conventional stack test methods or continuous emission monitors. Direct measurement of flow rate from batch kilns is not technically feasible because of the numerous vents and changing flow direction. In addition to the need to test multiple vents, an economic limitation to testing batch kilns is the

expense associated with testing over the long batch kiln cycle (e.g., often 20 or more hours) in which the emission concentration and kiln parameters change throughout the cycle. For CDKs, direct measurement of total kiln exhaust flow is not technically feasible due to the significant volume of fugitive emissions from the kiln openings. In addition to being unable to measure total flow, many CDKs have no specific emission point (or conduit) in which to measure emissions concentration (e.g., no outlet stack or hood, or in an indirect-fired kiln no kiln air return duct to a burner). This lack of a specific emission point for measurement of total kiln air flow and concentration is also an economic limitation, because even if outlet vents suitable for testing were present for a portion of exhaust, all such vents would need to be tested to ensure uniformity of concentration or to establish vent-specific concentrations, which would greatly increase source testing costs (while total flow would continue to remain uncertain, limiting usefulness of the data for prescribing or enforcing an emission standard).

3. Lumber Kiln Work Practice Standard

Work practices to reduce emissions from lumber kilns are often based on measures to minimize the amount of over-dried lumber produced. Lumber over-drying is of concern because HAP emissions have been shown to increase after the free water from the lumber is removed. As the free water evaporates, water bound within the cellular structure of the wood begins to be removed. Once the evaporative cooling of moisture on the surface of lumber ceases, the temperature of the lumber in the kiln increases and organic HAP emissions begin to increase. A work practice that minimizes over-drying limits organic HAP emissions from all types of kilns as well as combustion-related HAP emissions from direct-fired kilns since minimizing over-drying reduces fuel consumption, which results in less combustion-related HAP.

To develop a work practice standard for lumber kilns, we reviewed various permits and other information, including information received from ICR respondents regarding design, operation, and monitoring methods to minimize over-drying and limit HAP emissions. Several permits included "good operating practices" and kiln inspection and maintenance requirements to minimize over-drying. We also found that lumber manufacturers use a variety of practices to ensure that lumber is properly dried while balancing energy usage. For many manufacturers, the focus is on ensuring

⁹ The regulatory definition of BACT in 40 CFR 52.21(b)(12) states, "If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

that the lumber meets grade classification, which can be accomplished using a variety of techniques. For example, to meet the moisture content grade “KD19” for southern pine lumber, manufacturers must dry lumber to a maximum of 19 percent moisture. There are moisture grades other than KD19, such as KD15 or lower, for lumber to be exported. Lumber or wooden poles that will later undergo treatment may be dried to higher moisture levels than KD19. To ensure that the maximum grade moisture is met by most boards in the kiln load, kiln operators need to dry to a target moisture a few percent below the maximum moisture grade. Methods used to determine dryness of lumber vary. Temperature parameters monitored in the kiln during drying (e.g., wet or dry bulb temperature or temperature drop across the load) are used by kiln operators to determine when the drying cycle is complete. Temperature monitoring may be paired with hot checks in which sample boards are pulled from the kiln and checked for dryness near the end of the kiln cycle. In-kiln lumber moisture measurement during drying may be used, or lumber moisture may be checked with hand-held moisture meters after the drying cycle concludes. It is also common for lumber moisture measurement to be conducted downstream of the kiln (e.g., hand-held moisture meter checks or in-line moisture monitoring at the planer before lumber is packaged for shipment). Of the methods available for determining lumber moisture, the in-line moisture meter at the planer typically produces the largest number of lumber moisture readings. Given different kiln designs and the wide variety of techniques used to determine lumber dryness, the work practice to limit over-drying in the kiln requires some flexibility for site-specific considerations.

Based on our review of methods for limiting lumber over-drying, in 40 CFR 63.2241(d) we are proposing a work practice standard with 4 elements: (1) operation and maintenance for all kilns, (2) burner tune-up for direct-fired kilns, (3) a work practice option in which all kilns limit over-drying by operating below a temperature set point, conducting in-kiln moisture monitoring, or following a site-specific plan (for temperature and lumber moisture monitoring), and (4) minimum kiln-dried lumber moisture content limits below which lumber is considered to be over-dried lumber for all kilns for purposes of the PCWP NESHAP.

Operation and maintenance (O&M) plan. For the first element of the work

practice, we are proposing that facilities develop an O&M plan for all the lumber kilns located at the facility. Documentation of the O&M plan would be required to be retained onsite and to include procedures for maintaining the integrity of lumber kiln internal air flow and heat distribution components (e.g., baffles, fans, vents, heating coils, and temperature sensors) to provide as uniform a temperature and air flow as reasonably possible. Maintaining the heat distribution components prevents hot spots that could lead to increased HAP emissions and also prevents cold spots in the kiln that could lengthen the drying cycle for the entire load, thereby avoiding higher HAP emissions. The O&M plan would be required to include charge optimization practices to promote uniformity in lumber charged into the kiln (e.g., sizing, sorting, stickering, conditioning). Proper sorting results in less variation per kiln load that could lengthen the drying cycle and increase HAP emissions, and proper stickering ensures that air can flow through the lumber packages.¹⁰ To demonstrate compliance with the O&M plan, the facility would be required to conduct an annual inspection of lumber kiln integrity and review the charge optimization practices used. Facilities would be required to implement corrective actions (as needed) and maintain records of inspections and corrective actions taken under the O&M plan. State authorities delegated responsibility for implementing 40 CFR part 63, subpart DDDD, (or “delegated authorities”) may require modification of the O&M plan, as needed, upon review.

Kiln burner tune-up. For the second element of the work practice, we are proposing that facilities with batch and continuous direct-fired kilns conduct an annual burner tune-up to reduce the potential for combustion-related HAP emissions beyond the reduction in these emissions that results from minimizing lumber over-drying. Properly operating burners would reduce the potential for combustion-related HAP emissions from the kiln during routine operation and from any bypass stacks used temporarily during startup or shutdown of the kiln burner. We are proposing annual tune-ups for lumber kilns following the same procedures proposed for PCWP dryers.

Temperature, moisture, or site-specific plan limits. For the third element, we are proposing that facilities

select from 1 of 3 work practice options for minimizing lumber over-drying for each kiln at the facility: (1) temperature set point, (2) in-kiln moisture monitoring, or (3) a site-specific plan (for temperature and lumber moisture monitoring). While the EPA could require a site-specific plan for all lumber kilns, we acknowledge that lumber kilns operating at moderate temperatures compared to kilns of similar design, or kilns equipped with in-kiln moisture monitoring, are already operating in a manner that minimizes rapid over-drying. Thus, we are proposing to provide two streamlined options (in lieu of requiring a site-specific plan) for lumber kilns operating at moderate temperatures or using in-kiln lumber moisture monitoring techniques that reduce the potential for over-drying. These options consider that over-drying can occur more rapidly in kilns operating at higher temperatures and/or without a direct in-kiln lumber moisture content measurement system that provides automatic feedback to the kiln operator. These options encompass kiln features likely to be included in a site-specific plan to minimize over-drying (if a plan were to be developed for the kiln). These compliance demonstration alternatives to a site-specific plan streamline compliance for kilns that have less potential for over-drying and reduce burden for the delegated authority reviewing the site-specific plan.

Under the temperature option, the lumber kiln would be operated with a maximum dry bulb temperature set point of no more than 210 °F for batch indirect-fired (IF) kilns, 235 degrees Fahrenheit (°F) for batch direct-fired kilns, or 245 °F for continuous indirect-fired or continuous direct-fired kilns. The proposed temperatures of 210 °F, 235 °F, and 245 °F represent both average and median dry bulb temperature used in lumber kilns in the source category that were within 5 °F of the proposed temperature. These temperatures are proposed because they represent temperatures below which approximately half of kilns operate while the remaining half of kilns operate at higher temperatures that could accelerate over-drying. Facilities would be required to continuously measure the dry bulb temperature during the kiln drying cycle, record the dry bulb temperature at least every 15 minutes, calculate the 3-hour block average temperature, and maintain the 3-hour block average below the temperature limit. See proposed 40 CFR 63.2269(a)–(b) and (m) and 40 CFR 63.2270(h) for more details on

¹⁰ Additional information on lumber kiln O&M can be found in Simpson, William T., ed. 1991. *Dry Kiln Operator's Manual*. Agricultural Handbook AH-188. Madison, WI: U.S. Department of Agriculture, Forest Service, Forest Products Laboratory.

temperature monitoring under the PCWP NESHAP.

Under the in-kiln moisture measurement option, the lumber kiln would operate using a direct, in-kiln continuous lumber moisture monitoring technique that provides automated feedback from within the kiln to the kiln operator control panel during the drying cycle. Kiln owners and operators would be required to operate the kiln to dry to a semiannual average lumber moisture content above the minimum limit of moisture content proposed in paragraph 40 CFR 63.2241(e)(3)(ii) and table 11 to subpart DDDD of 40 CFR part 63, as discussed later in this preamble. We are proposing the in-kiln lumber moisture measurement option to promote direct measurement and use of lumber moisture content monitoring as a kiln control parameter during high-temperature drying (*i.e.*, in kilns operating above the dry bulb temperature set points under the work practice temperature option). An example of an in-kiln direct lumber moisture measurement technique is use of 2 steel plates inserted into packages of lumber spatially distributed throughout the kiln. The electrical resistance between the plates is measured and relayed to a moisture meter which supplies moisture measurements to the kiln control software. We are proposing that at least 1 lumber moisture reading per 20,000 board feet (BF) of lumber in the kiln load be taken and that the batch average lumber moisture content be determined at the end of the batch cycle (when the lumber has reached its lowest kiln-dried moisture content). The requirement for 1 lumber moisture reading per 20,000 BF (which is the same as 20 thousand board feet (20 MBF)) is proposed to ensure that there are multiple moisture measurements in different areas of the kiln, with the number of lumber moisture monitors being scaled to kiln capacity. For example, a lumber kiln drying 160 MBF per batch would require at least 8 lumber moisture monitors to be distributed throughout the kiln load. For CDKs, we are proposing that facilities measure the lumber moisture content at the completion of drying for each package of lumber (when the lumber has reached its lowest kiln-dried moisture content). Because different lumber grades can be produced in a given lumber kiln at different times, we are proposing that a ratio of measured lumber moisture divided by the minimum kiln-dried lumber moisture limit be developed for each batch kiln load and for each package of lumber dried in a CDK. If the

semiannual average of all the ratios is greater than or equal to 1 for the kiln, then compliance would be demonstrated. The semiannual average ratio of measured moisture divided by the minimum kiln-dried lumber moisture limit would be reported in the semiannual report. A semiannual averaging time is proposed to correspond with the semiannual reporting frequency already required for reporting under the PCWP NESHAP, and because a semiannual average provides flexibility for the variability associated with drying lumber of different dimensions cut from logs with naturally occurring initial moisture variations (*e.g.*, seasonal or tree stand variations). See proposed 40 CFR 63.2241(e)(3)(ii) and 40 CFR 63.2270(i) for more details on the proposed methodology for calculating the semiannual average from kiln-dried lumber moisture measurements.

Under the site-specific plan option, facilities would develop and operate according to a site-specific plan to minimize lumber over-drying through temperature and lumber moisture monitoring. The site-specific plan would be required to be submitted to the delegated authority for approval. The site-specific limits from the plan would then have to be incorporated into the facility's operating permit when it is next reopened or renewed, as applicable.

The site-specific plan would be required to: identify one temperature parameter (such as wet or dry bulb temperature, wet bulb depression, or temperature drop across the load) to be continuously monitored during the kiln drying cycle; include a description of how the temperature parameter is measured and used to minimize over-drying of lumber; and include a site-specific limit for the temperature parameter that minimizes over-drying. Facilities would be required to continuously monitor the temperature parameter no less often than every 15 minutes and calculate the 3-hour block average for comparison to the site-specific temperature limit. See proposed 40 CFR 63.2269(a)–(b) and 40 CFR 63.2270(h) for more details on temperature monitoring under the PCWP NESHAP.

In addition, the site-specific plan would be required to: include a site-specific method for monitoring kiln-dried lumber moisture content (weight percent, dry basis); specify the location of such monitoring within the lumber manufacturing process (for example, at the kiln unloading track, in lumber storage, or at the planer); specify the minimum kiln-dried lumber moisture

content limit based on the lumber moisture grades produced at the facility based on 40 CFR 63.2241(e)(3)(iii) and table 11 to subpart DDDD of 40 CFR part 63; and adhere to a minimum data requirement of one moisture measurement per 20,000 BF. Facilities would be required to calculate and record the monthly average kiln-dried lumber moisture content, compare the monthly average to the minimum kiln-dried lumber moisture content limit, and take corrective action if the monthly average lumber moisture content is below the minimum limit. Facilities would be required to maintain records of corrective actions taken and report corrective actions in the semiannual report. In addition, facilities would be required to calculate the semiannual average of batch or continuous kiln lumber moisture measurements and compare the semiannual average to the minimum kiln-dried lumber moisture content limit to determine compliance. The monthly averages with records of corrective action (when needed) are proposed to provide interim indications of compliance before the semiannual average is determined because facilities using a site-specific plan are likely to be measuring the moisture of kiln-dried lumber downstream of the kiln (*e.g.*, at the planer).

The site-specific plan containing limits for temperature and lumber moisture content would have to be developed and submitted to the delegated authority within 180 days after the effective date of the final rule. The written site-specific plan would have to be maintained onsite at the facility and would be enforceable upon the compliance date specified in the rule. Facilities would be required to report deviations from the site-specific plan following the compliance date. Once the site-specific plan is approved by the delegated authority, the plan requirements would be incorporated into the facility's title V operating permit when the permit is next reopened or renewed, as applicable.

Kiln-dried moisture minimum limit. In the fourth and final element of the work practice to minimize lumber over-drying, we are proposing minimum limits of kiln-dried lumber moisture content (weight percent on a dry basis) that are considered to be over-dried lumber for purposes of the PCWP NESHAP. In proposed 40 CFR 63.6241(e)(4) and proposed table 11 to subpart DDDD of 40 CFR part 63, the “maximum lumber moisture grade” means the upper limit of lumber moisture content (weight percent on a dry basis) that meets the relevant lumber grade standard for a lumber

product. The proposed minimum limit of kiln-dried lumber moisture content varies according to the maximum lumber moisture grade as shown in proposed table 11 to subpart DDDD of 40 CFR part 63. The minimum limits of kiln-dried lumber moisture content proposed acknowledge the fact that different lumber moisture grades are produced and that enough margin is needed to encompass the target lumber moisture (which is a few percent below the grade moisture to ensure the lumber meets grade) and allow for variability that occurs around the target moisture. The minimum limits of lumber moisture proposed in table 11 to subpart DDDD of 40 CFR part 63 reflect the following moistures (all on a weight percent, dry basis):

- For lumber with maximum lumber moisture grade above 22 percent, the proposed minimum limit below which lumber is considered over-dried is 15 percent moisture. A minimum limit of 15 percent moisture was selected because a limit of 15 percent lumber moisture is included in at least 1 air permit for a lumber facility producing moisture grades higher than KD-19.

- For lumber with a maximum lumber moisture grade of 19 to 21 percent, the proposed minimum limit below which lumber is considered over-dried is 12 percent moisture. A minimum limit of 12 percent was selected because this limit is consistent with the limit indicated in several air permits for facilities producing KD-19, which is a grade produced in high volume.

- Consistent with the 7 percent difference between KD-19 and a 12 percent minimum limit, we are proposing the maximum grade moisture minus 7 percent as the minimum kiln-dried lumber moisture limit for grades with 18 down to 12 percent maximum moisture content (*e.g.*, 12 percent grade – 7 percent = 5 percent minimum kiln-dried lumber moisture limit).

- For lumber with maximum lumber moisture grade less than or equal to 10 percent, as required for some products to be exported, the proposed minimum limit below which lumber is considered over-dried is half the maximum lumber moisture grade. A 5 percent minimum kiln-dried lumber moisture limit is proposed for lumber with a maximum moisture grade of 11 percent, consistent with the minimum limit of 5 percent for grades of 10 and 12 percent moisture.

We estimate the HAP emission reduction achieved by the work practice to be 488 tpy for existing sources. We estimate that the work practice would also reduce 6,700 tpy of VOC emissions

(as WPP1¹¹) from existing sources. For new sources, we estimate that the work practice would result in emission reductions of 77 tpy HAP and 1,000 tpy VOC (as WPP1).

4. Consideration of Add-On Controls

The EPA has not identified any lumber kilns with add-on air pollution controls. The EPA, as well as state permitting authorities, have evaluated the possibility of capturing and controlling emissions from lumber kilns and in each case concluded that capture and control of lumber kiln emissions is not technically feasible or cost effective for VOC emissions from batch or continuous kilns. The technologies considered and rejected as technically infeasible in BACT determinations include oxidizers (RTO and RCO), carbon adsorption, condensation, biofilters, and wet scrubbers (also known as absorbers). In some BACT determinations, it was noted that if an RTO were to be attempted for use on a lumber kiln, duct heaters and a WESP would likely also be needed to prevent resin buildup in the ductwork (for safety) as well as to protect the thermal media in an RTO or catalytic media in an RCO. Technologies rejected based on technical infeasibility for control of VOC are also infeasible for control of HAP in the same exhaust stream. Therefore, we do not consider add-on controls for lumber kilns to be a viable option for reducing HAP emissions. No emission reduction measures more stringent than the proposed work practice were identified.

C. What MACT standards are we proposing for process units with organic HAP emissions?

The EPA is proposing MACT standards to resolve unregulated HAP emissions from process units that had “no control” MACT determinations in the 2004 NESHAP that were remanded and vacated. In addition to MACT standards for lumber kilns, the EPA is proposing MACT standards for various process units in the PCWP source category, including various RMH process units, atmospheric refiners, stand-alone digesters, fiber washers, fiberboard mat dryers at existing sources, hardboard press predryers at existing sources, and log vats. Some of these process units are already subject

to new source HAP standards in the 2004 PCWP NESHAP, including fiberboard mat dryers, hardboard press predryers, and reconstituted wood products board coolers (which are a type of RMH unit) at new and reconstructed sources. Mixed PCWP process streams routed to HAP control devices subject to the current HAP emission limits in table 1B to subpart DDDD of 40 CFR part 63 are also already subject to the 2004 PCWP NESHAP. This section of the preamble describes the MACT standards we are proposing for emissions streams with unregulated HAP emissions. A detailed description of the process units being regulated and supporting information for the proposed standards are provided in the memorandum, *Development of Emission Standards for Remanded Process Units Under the Plywood and Composite Wood Products NESHAP*, in the docket for this action.

1. Resinated Material Handling (RMH) Process Units

The PCWP affected source is the collection of process units used to produce PCWP at a PCWP manufacturing facility, including various dryers and reconstituted wood products presses which are already subject to emission standards under the PCWP NESHAP and other process units for which prior “no control” MACT determinations were vacated and remanded to EPA. Many of the process units with the prior “no control” MACT determinations are RMH process units within the PCWP affected source, including resin tanks, softwood and hardwood plywood presses, engineered wood products presses and curing chambers, blenders, formers, finishing saws, finishing sanders, panel trim chippers, reconstituted wood products board coolers (at existing affected sources), hardboard humidifiers, and wastewater operations. These process units handle resin or resinated wood material downstream of the point in the PCWP process where resin is applied.

The RMH process units are not designed and constructed in a way that allows for HAP emissions capture or measurement. It is not feasible to prescribe or enforce an emission standard for control of HAP from RMH process units. The RMH process units are equipment within the PCWP production building (or outdoor wastewater operations) without any enclosure, conveyance, or distinct HAP emissions stream that can feasibly be emitted through a conveyance. For example, dry formers, saws, and sanders have pick-up points for removal of wood material as it is trimmed, but the

¹¹ VOC as WPP1 is based on the wood products protocol in which VOC emissions as propane are corrected for oxygenated compounds that have a low response to the flame ionization detector used to measure hydrocarbons, by adding formaldehyde and 35 percent of methanol emitted. WPP1 VOC was used in the assessment of lumber kiln emissions consistent with the approach used by permitting authorities.

entire process unit is not enclosed or isolated; engineered wood products presses are too large to enclose; plywood presses cannot be enclosed for operator safety reasons; and board coolers at existing sources cannot be enclosed for equipment functionality reasons. Emissions from RMH process units are fugitive in nature such that application of emissions measurement methodology is not technically feasible. Further, emissions capture and measurement from hundreds of individual RMH process units would not be economically feasible (*e.g.*, with testing costs estimated to exceed \$20 million nationwide assuming that facilities could capture emissions). For these reasons, it is not feasible to prescribe or enforce an emission standard for RMH process units. Therefore, the EPA is proposing work practice standards under CAA section 112(h).

To develop work practice standards under CAA section 112(h), consistent with CAA section 112(d), measures used by the best performing sources to reduce or eliminate emissions of HAP through process changes or substitution of materials were considered. This approach is consistent with CAA section 112(d)(2)(A). The potential for HAP emissions from RMH process units relates to the material being processed (*i.e.*, resin and wood). Standards for RMH units pertaining to resin-related and wood-related emissions are discussed in the following subsections.

a. Resin-Related Emissions From RMH Process Units

Most PCWP resins are amino/phenolic resins such as phenol formaldehyde (PF), melamine urea formaldehyde (MUF), urea formaldehyde (UF) with urea scavenger, melamine formaldehyde (MF), or phenol resorcinol formaldehyde (PRF). Isocyanates such as MDI are also used. The HAP associated with use of amino/phenolic resins at PCWP facilities include formaldehyde (CAS 50-00-0), phenol (CAS 108-95-2) and methanol (CAS 67-56-1). The HAP associated with MDI resin is 4,4'-Methylenediphenyl Diisocyanate (CAS 101-68-8). Some PCWP products can only be made with specific types or formulations of resins. Other products are made with 1 or more types of resins (*e.g.*, OSB can be made with PF, MDI, or PF and MDI in the same board). The PCWP resins typically are a liquid with high solids content (*e.g.*, up to 70 percent solids) as received or may be delivered and applied in powdered form.

The potential for resin-related HAP emissions from RMH process units relates to the free HAP content and volatility of the resin system used. The PCWP resin systems used typically have very low free HAP content (weight percent) or low vapor pressure depending on the resin type and application. For example, most types of amino/phenolic resins are non-HAP resins which can be defined as a resin with HAP contents below 0.1 percent by mass for Occupational Safety and Health Administration-defined carcinogens as specified in section A.6.4 of appendix A to 29 CFR 1910.1200, and below 1.0 percent by mass for other HAP compounds.

However, some amino/phenolic resin formulations essential to manufacturing dry-process hardboard or I-joists have slightly higher weight percentages of some HAP than non-HAP resins but have low vapor pressure which reduces the potential for HAP emissions from RMH process units at facilities used to make those products. Similarly, MDI resins would not be considered non-HAP resins due to their percentage by weight MDI content, but MDI resins have very low vapor pressure as received and used in RMH process units. In developing work practice standards for RMH units, it is necessary to limit resin-related HAP emissions without precluding the types of PCWP products covered under the PCWP NESHAP from being produced. A work practice standard with enforceable options to use a non-HAP resin system or meet a vapor pressure limit adheres to the CAA while allowing the different types of PCWP products covered under the PCWP NESHAP to be produced.

Information on resin HAP content (HAP percent, by weight) and resin vapor pressure (in kilopascals [kPa] or pounds per square inch absolute [psia]) is often available in safety data sheets (SDS) or other technical documentation accompanying the resin when it is received from the resin supplier. Some PCWP manufacturers may dilute amino/phenolic resins when preparing them for use, which would reduce the mass fraction of free HAP content or corresponding vapor pressure of the free HAP in the resin. Therefore, resin supplier information for the "as received" resin, before the resin is diluted or mixed with wood, is the most consistently available source of information to use as the basis of the work practice standards pertaining to resin-related HAP.

When received, PCWP resins are stored in fixed roof resin tanks at the PCWP facility at ambient temperature. Resin tanks are the first type of RMH

process units in which resins are used in the PCWP process. The average-size resin tank in the PCWP industry is 12,500 gallons while the maximum is 47,000 gallons. Limited vapor pressure data are currently available to the EPA for resins used at PCWP facilities. Therefore, vapor pressure criteria in the Amino/Phenolic Resin NESHAP (40 CFR part 63, subpart OOO) were reviewed in addition to information available from PCWP facilities. The maximum true vapor pressure limits for applying controls for storage vessels storing liquids containing HAP under the Amino/Phenolic Resin NESHAP are 13.1 kPa (1.9 psia) for tanks with 20,000 to 40,000 gallon capacity and 5.2 kPa (0.75 psia) for storage vessels with 40,000 to 90,000 gallon capacity. A maximum true vapor pressure limit of 5.2 kPa (0.75 psia) corresponding with the largest PCWP resin tanks is proposed as the vapor pressure work practice option for PCWP resin-related HAP emissions. This vapor pressure limit would apply for amino/phenolic resins that are not non-HAP resins as well as for MDI resins. For the PCWP NESHAP, the maximum true vapor pressure of the resin as received would be defined in 40 CFR 63.2292 as the equilibrium partial pressure exerted by HAP in the stored liquid at the temperature equal to the highest calendar-month average of the liquid storage temperature for liquids stored above or below the ambient temperature, or at the local maximum monthly average temperature as reported by the National Weather Service for liquids stored at the ambient temperature, as determined: (1) from safety data sheets or other technical information provided by the PCWP resin supplier; or (2) standard reference texts; or (3) by the ASTM Method D2879-18 (which is proposed to be incorporated by reference in § 63.14); or (4) any other method approved by the Administrator.

b. Wood-Related Emissions From RMH Process Units

The potential for wood-related organic HAP emissions from RMH process units is reduced when the wood is purchased pre-dried or is dried in a dryer upstream from the RMH process units. Organic HAP in wood is released during the drying process (*i.e.*, prior to the RMH process units) and dryers are controlled to meet the emission limits established in the 2004 PCWP NESHAP. Most RMH process units after the drying process are not heated, which further limits the potential for wood-related organic HAP emissions. Even if the RMH process unit is heated (such as

plywood or engineered wood product presses), if the wood processed has been previously dried then the potential for wood-related HAP emissions is reduced because dryers operate at higher temperatures than presses. A standard that requires processing of dried wood will minimize wood-related organic HAP emissions from RMH process units in the affected source.

c. RMH Process Unit Proposed Standards

We are proposing work practice standards to require new and existing facilities with RMH process units to (i) use only a non-HAP resin (defined in 40 CFR 63.2292), or (ii) use a resin with a maximum true vapor pressure of less than or equal to 5.2 kPa (0.75 psia) as defined in 40 CFR 63.2292, or (iii) use a combination of resins meeting either (i) or (ii). Facilities with RMH process units would also be required to process wood material that was purchased pre-dried to a moisture content of no more than 30 percent (weight percent, dry basis) or that has been dried in a dryer located at the PCWP facility. This requirement to process dried wood would not apply for wet formers and wastewater operations.

No options more stringent than the RMH process unit work practices were identified for resin tanks, softwood and hardwood plywood presses, engineered wood products presses and curing chambers, blenders, formers, finishing saws, finishing sanders, panel trim chippers, or hardboard humidifiers at new or existing affected sources, or for reconstituted wood products board coolers at existing affected sources. Reconstituted wood products board coolers at new affected sources are already subject to standards under the PCWP NESHAP. For wastewater operations, the EPA is proposing a work practice in addition to the RMH process unit standards to further limit the potential for HAP emissions. Facilities with wastewater operations would be required to implement one of the following measures:

- Follow the plan required in 40 CFR 63.2268 for wet control devices used as the sole means of reducing HAP emissions from PCWP process units; or
- Reduce the volume of wastewater to be processed by reusing or recirculating wastewater in the PCWP process or air pollution control system; or
- Store wastewater in a closed system; or
- Treat the wastewater by using an onsite biological treatment system, or by routing the wastewater to an offsite POTW or industrial wastewater treatment facility.

The applicability of these work practices for wastewater operations depends on the type of PCWP produced and specific equipment generating wastewater. Requiring one of the above work practices in addition to the RMH standards was identified as a more stringent option.

The emissions reductions associated with the work practices for RMH units are estimated to be 6.7 tpy of HAP from existing sources. No HAP reduction is estimated for new sources projected in the next 5 years because all facilities are expected meet the standards upon startup. No quantifiable HAP reductions are expected from the additional work practice for wastewater operations.

2. Atmospheric Refiners

Atmospheric refiners operate with continuous infeed and outfeed of wood material and under atmospheric pressure for refining (rubbing, grinding, or milling) wood material into fibers or particles used in particleboard or dry formed hardboard production. Atmospheric refiners are further characterized based on their placement before or after dryers in the PCWP production process. We are proposing the following definitions for inclusion in the PCWP NESHAP to distinguish between the 2 types of atmospheric refiners.

Dried wood atmospheric refiner means an atmospheric refiner used to process wood that has been dried onsite in a dryer at the PCWP affected facility for use in PCWP in which no more than 10 percent (by weight) of the atmospheric refiner annual throughput has not been previously dried onsite.

Green wood atmospheric refiner means an atmospheric refiner used to process wood for use in PCWP before it has been dried onsite in a dryer at the PCWP affected facility. Green wood atmospheric refiners include atmospheric refiners that process mixtures of wood not previously dried onsite (e.g., green wood) and wood previously dried onsite (e.g., board trim) in which wood not previously dried onsite comprises more than 10 percent (by weight) of the atmospheric refiner annual throughput.

The above definitions include a 10 percent (by weight) criteria to provide clarity for atmospheric refiners that process material recycled from various points in the PCWP process. An atmospheric refiner "system" may comprise 1 or more atmospheric refiners with the same emission point (e.g., 2 particleboard refiners venting to the same baghouse).

a. Dried Wood Atmospheric Refiners

Based on available information from the 2017 ICR and more recent updates, there are 6 dried wood atmospheric refiner systems following PCWP dryers. Each of the 6 dried wood atmospheric refiner systems is controlled by a baghouse for dust collection. Emissions data for total HAP are available from the 2022 CAA section 114 survey testing for 2 of the dried wood atmospheric refiner systems. Because there are fewer than 30 systems, the MACT floor for existing sources is based on the average of the top 5 systems, or in this case the 2 systems with available total HAP emissions data. The MACT floor for new sources is based on the single best performing system. The MACT floor UPLs for existing and new systems were calculated according to the methodology referenced in section III.B of this preamble. Based on these calculations, the total HAP MACT floor for existing dried wood atmospheric refiners following dryers is 4.1E-03 lb/ODT. The total HAP MACT floor for new sources is 3.3E-03 lb/ODT.

Based on the average performance level for dried wood atmospheric refiners, we anticipate that the existing and new source total HAP MACT floors could be met without the use of add-on HAP controls. No HAP reduction is estimated for existing sources. No new dried wood atmospheric refiners are projected to be constructed or reconstructed in the next 5 years.

The EPA considered an option more stringent than the MACT floor to require dried wood atmospheric refiners to meet the emission limits in table 1B to subpart DDDD of 40 CFR part 63 based on add-on HAP control. With this beyond-the-floor option, nationwide emissions reductions for existing sources were estimated to be 0.9 tpy of HAP reduced and 28 tpy of VOC reduced. The nationwide capital and annual costs of this beyond-the-floor option are \$19 million and \$7.8 million per year, with a cost effectiveness of \$8.4 million per ton of HAP reduced and \$284,000 per ton of VOC reduced. Energy impacts associated with the beyond-the-floor option for existing sources include 24,000 MW-hr/year electricity use (with associated secondary air emission impacts) and 475,000 MMBtu/yr in natural gas usage. In addition, an estimated 192,000 gal/year of wastewater (for RTO washouts) and 113 tons/year of solid waste are estimated to be generated.

After considering the regulatory options for dried wood atmospheric refiners, the EPA is proposing MACT standards based on the MACT floor for

existing and new dried wood atmospheric refiners. The more stringent beyond-the-floor option was rejected due to the high costs relative to the emission reductions that would be achieved, energy usage, and other non-air quality environmental impacts. Although the more stringent beyond-the-floor option is not being proposed, we are proposing to include a provision in 40 CFR 63.2240(d)(6) to give facilities the option of complying with the more stringent limits in table 1B to subpart DDDD of 40 CFR part 63 in place of the proposed limits in table 1C to subpart DDDD of 40 CFR part 63 if they choose to meet the more stringent option.

b. Green Wood Atmospheric Refiners

Existing sources. Based on available information, there are 28 green wood atmospheric refiner systems that precede dryers in the PCWP process. Controls used on green wood atmospheric refiners include cyclones, baghouses, and oxidizers used to control or co-control dryers. Total HAP emissions data are available from the 2022 CAA section 114 survey testing for 5 green wood atmospheric refiner systems, including 3 systems with oxidizers¹² and 2 systems with baghouses. The 3 systems with oxidizers are co-controlled with other PCWP process units (e.g., dryers, presses) but had measurable emission streams at the inlet to the HAP control device containing only emissions from the green wood atmospheric refiners. Because the green wood atmospheric refiner emissions could be determined at the control device inlet, the green wood atmospheric refiner emissions at the control device outlet could be estimated. (Estimation of the outlet HAP emission rate attributable to the green wood atmospheric refiners was necessary because the measured HAP emission rate at the control device outlet exceeded the atmospheric refiner inlet emissions, due to the greater contribution to the total emissions from co-controlled dryers and/or presses.) Based on the emission reduction required for green rotary dryers in table 1B to subpart DDDD of 40 CFR part 63, we estimated that the green wood atmospheric refiner emissions at the HAP control outlet would be 90 percent below the inlet for each run for purposes of obtaining run values for use in the MACT floor UPL calculation. Using the outlet test run data for the 5 systems, the total HAP MACT floor UPL

for existing source green wood atmospheric refiners is $1.2\text{E}-01$ lb/ODT.

Based on the average performance level for green wood atmospheric refiners, we expect that existing sources would meet the total HAP MACT floor. An option more stringent than the MACT floor would be to require existing green wood atmospheric refiners to meet the emission limits in table 1B to subpart DDDD of 40 CFR part 63. This alternative could be considered as a beyond-the-floor regulatory option for all green wood atmospheric refiners and allowed as an option for those units already co-controlled with dryers meeting the table 1B limits.

Nationwide costs of the more stringent beyond-the-floor option for existing green wood atmospheric refiners (e.g., RTO control) were estimated to be \$56 million capital and \$23 million per year, with nationwide reductions of 59 tpy HAP and 834 tpy VOC, and cost effectiveness of \$388,000/ton HAP reduction and \$27,000/ton VOC reduced. Energy impacts associated with the beyond-the-floor option for existing sources include 64,000 MW-hr/year electricity use (with associated secondary air emission impacts) and 1,100 billion Btu/yr in natural gas usage. In addition, an estimated 768,000 gal/year of wastewater and 300 tons/year of solid waste are estimated to be generated.

The EPA is proposing that MACT for existing source green wood atmospheric refiners be based on the MACT floor. The EPA is proposing to reject the more stringent beyond-the-floor option (table 1B limits) due to high costs compared to the emissions reductions that could be achieved, energy usage, and other non-air quality environmental impacts. Although the more-stringent beyond the floor option is not being proposed, we are proposing to include a provision in 40 CFR 63.2240(d)(6) to give facilities the option of complying with the more stringent limits in table 1B to subpart DDDD of 40 CFR part 63 in place of the proposed limits in table 1C to subpart DDDD of 40 CFR part 63 if they choose to meet the more-stringent option.

New sources. The total HAP MACT floor for green wood atmospheric refiners at new sources, based on the UPL of the data set for the single best performing system, is $2.4\text{E}-03$ lb/ODT. We note that this UPL calculation is based on a limited data set.¹³ Comparing the MACT floor to the average performance level achieved by all of the

green wood atmospheric refiners suggests that add-on HAP control (e.g., oxidizer) would be needed by most systems to meet the MACT floor for new sources. The same level of HAP control (e.g., oxidizer) would be achieved by new source green wood atmospheric refiners that are co-controlled with process units required to meet the emission limits in table 1B to subpart DDDD of 40 CFR part 63. Therefore, we are proposing to provide the option in 40 CFR 63.2240(d)(6) that would allow green wood atmospheric refiners to meet either the new source MACT floor UPL specific to green wood atmospheric refiners or the current table 1B limits, because either limit would result in the same level of HAP control (e.g., that achieved by use of an oxidizer). Emission reductions were estimated to be 4.9 tpy organic HAP and 77 tpy VOC. No options more stringent than the MACT floor were identified. Therefore, we are proposing standards for new source green wood atmospheric refiners based on the MACT floor.

3. Stand-Alone Digesters and Fiber Washers

One wet/dry process hardboard facility operates a batch stand-alone digester and a fiber washer that have unregulated HAP emissions. Stand-alone digesters are used to steam or water soak wood chips so that they may be easily rubbed apart or ground into fibers in atmospheric refiners that follow the digesters. Stand-alone digesters have batch operating cycles that differ from pressurized refiner pre-steaming vessels (sometimes called “digesters”) used to preheat wood chips prior to refining. Pressurized refiner pre-steaming vessels have continuous infeed and outfeed without pressure release between the pre-steamer and pressurized refiner. We are proposing to add the following definition of “stand-alone digester” to the PCWP NESHAP to clearly distinguish this type of unit from pressurized refiners, which are already subject to the PCWP NESHAP.

Stand-alone digester means a pressure vessel used to heat and soften wood chips (usually by steaming) before the chips are sent to a separate process unit for refining into fiber. Stand-alone digesters operate in batch cycles that include filling with wood chips, pressurization, cooking of wood chips under pressure, pressure release (purge) venting, and chip discharge (blow) from the pressure vessel. Venting of emissions from stand-alone digesters is separate from any downstream refining process. A stand-alone digester is a process unit.

Pressurized refiners are already subject to emission standards from the 2004 PCWP NESHAP. We are proposing to

¹² A fourth green wood refiner system with RCO does not have isolatable inlet or outlet emissions because it vents straight into dryer(s) controlled by the RCO.

¹³ See the memorandum, *Approach for Applying the Upper Prediction Limit to Limited Datasets*, in the docket for this action for details on our review of the data sets and conclusions regarding appropriateness of the proposed MACT floors.

amend the current definition of pressurized refiner in the PCWP NESHAP to state that: "Pressurized refineries include pre-steaming vessels that operate under pressure to continuously feed and vent through the pressurized refiner." The amended definition would distinguish between pre-steaming vessels that are part of pressurized refiner systems and stand-alone digesters.

One batch stand-alone digester system at a wet/dry hardboard process was identified. Measuring emissions from the stand-alone digester vents is not feasible because the flow rate from the vents is inconsistent and varies widely with the intermittent "purge" and "blow" cycles. In addition, entrained water droplets in the high moisture stream (composed primarily of steam) can interfere with emissions samples. Considering the inability to accurately measure emissions and the over 60-year age of the 1 remaining stand-alone digester in the PCWP industry where hardboard production has severely declined due to economic constraints,¹⁴ we have concluded that application of emissions measurement methodology is not practicable due to technological and economic limitations and that a work practice is the appropriate format of standard according to CAA section 112(h)(2)(B). The potential for HAP emissions from stand-alone digesters is reduced when: (1) clean steam from the boiler is used for the digestion process (as opposed to steam potentially contaminated with HAP being reused from another process); and (2) HAP-containing or wood pulping chemicals¹⁵ are not added to the digestion process. Thus, we are proposing a work practice requiring clean steam to be used in the digesters and prohibiting addition of HAP-containing or wood pulping chemicals to the digestion process. Initial and continuous compliance with the stand-alone digester work practice is proposed to be demonstrated through recordkeeping. No regulatory options more stringent than the work practice were identified for further consideration for existing or new stand-alone digesters. No new fiberboard or

hardboard mills are projected; therefore, no new PCWP affected sources are expected to use stand-alone digesters.

Fiber washers are units in which water-soluble components of wood (hemicellulose and sugars) that have been produced during digesting and refining are removed from the wood fiber before the fiber is used in fiberboard or hardboard production. In a fiber washer, wet fiber leaving a refiner is further diluted with water and then passed over a filter, leaving the cleaned fiber on the surface. With the decline in the number of wet process fiberboard and hardboard facilities since the 2004 NESHAP was promulgated, only 1 fiber washer remains in operation in the PCWP industry. This vacuum drum-type washer is over 60 years old (due to economic constraints), is uncontrolled, and is not configured with an enclosure to capture emissions for measurement. Because there are technological and economic limitations to measuring emissions from this washer, this unit meets the criteria under CAA section 112(h)(2)(B) for establishing a work practice standard. The potential for HAP emissions from the fiber washer is already reduced because the facility uses fresh water to perform washing (as opposed to reusing process water) and does not use any wood pulping chemicals to dissolve lignin or HAP-containing chemicals (such as resins) in the manufacturing process. The lignin that remains in the fiber helps bind the wood fibers together to form the hardboard product. We are proposing a work practice for PCWP fiber washers to use fresh water for washing and processing fiber without addition of wood pulping or HAP-containing chemicals. Initial and continuous compliance with the fiber washer work practice is proposed to be demonstrated through recordkeeping. No regulatory options more stringent than the work practice were identified for further consideration for existing or new fiber washers. No new fiberboard or hardboard mills are projected; therefore, no new PCWP affected sources are expected to use fiber washers. No HAP emission reductions are expected to result from the work practices standards because they are already in use.

4. Fiberboard Mat Dryers and Press Predryers at Existing Sources

Fiberboard mat dryers are conveyor-type dryers used to dry wet-formed fiber mats. Press predryers are used in the wet/dry hardboard process to remove additional moisture from the hardboard mat after it exits the fiberboard mat dryer before the mat enters the hardboard press.

The PCWP NESHAP contains HAP emission standards for fiberboard mat dryers (heated zones) and hardboard press predryers at new sources (*i.e.*, the add-on control device compliance options in table 1B to subpart DDDD of 40 CFR part 63 or the production-based compliance option in table 1A to subpart DDDD of 40 CFR part 63). In this action, the EPA is proposing standards for the heated zones of an existing fiberboard mat dryer and hardboard press predryer that are unregulated for HAP at a wet/dry process hardboard facility. Both of these existing dryers are uncontrolled.

According to CAA section 112(d)(3)(B), because there are fewer than 30 sources, the MACT floor for existing sources must be based on the "average emission limitation achieved by the best performing 5 sources" or in this case the one fiberboard mat dryer and one predryer with unregulated HAP emissions. The average emission limitation achieved for purposes of setting the MACT floor emission level is based on the upper limit (UL) of the test data when there is only 1 source (where prediction is not required). The UL for each dryer was calculated using HAP test data collected in 2022 through a CAA section 114 survey.

For the fiberboard mat dryer (heated zones), the MACT floor based on the UL of the test data is 4.9E-02 lb total HAP per MSF on a 1/8" thickness basis. The MACT floor based on the UL of the test data for the press predryer is 8.0E-02 lb total HAP per MSF on a 1/8" thickness basis. We note that the MACT floor calculations were based on limited data sets.¹⁶ No organic HAP emission reductions are associated with the MACT floor options.

We considered beyond-the-floor regulatory options for the existing fiberboard mat dryer and press predryer, which would be to route the dryers to incineration-based control, such as an RTO, in order to meet the emission limits of table 1B to subpart DDDD of 40 CFR part 63 as required in the NESHAP for new sources. Both dryers were considered together because using 1 RTO to treat emission streams from both dryers would be more cost-effective than 2 separate HAP control devices. In addition to RTO installation and operating costs, compliance costs would include emissions testing, RTO temperature monitoring, reporting, and recordkeeping. Total capital and annual costs associated with the beyond-the-

¹⁴ Eighteen facilities manufacturing hardboard were in operation when the PCWP NESHAP was promulgated in 2004. Four hardboard manufacturing facilities remain in operation today.

¹⁵ Wood pulping chemicals added to dissolve lignin in wood include sodium sulfide (Na₂S) in combination with sodium hydroxide (NaOH), sulfurous acid (H₂SO₃) compounds, or sodium sulfite (Na₂SO₃) in combination with sodium carbonate (Na₂CO₃). Lignin removal is not necessary in the hardboard industry where natural lignin helps bind wood fibers in processes where synthetic resins are not used.

¹⁶ See the memorandum, *Approach for Applying the Upper Prediction Limit to Limited Datasets*, in the docket for this action for details on our review of the data sets and conclusions regarding appropriateness of the proposed MACT floors.

floor option are estimated to be \$2.2 million and 1.0 million per year, respectively. Reductions in HAP and VOC associated with the beyond-the-floor option for both dryers are estimated to be 8.1 tpy organic HAP and 16 tpy VOC, for a cost effectiveness of \$117,000/ton of organic HAP reduced and \$61,000/ton of VOC reduced. Energy impacts associated with the beyond-the-floor option for existing sources include 3,000 MW-hr/year electricity use (with associated secondary air emission impacts) and 50,000 MMBtu/yr in natural gas usage. In addition, an estimated 21,000 gal/year of wastewater and 8.2 tons/year of solid waste are estimated to be generated from oxidizer media washouts and replacements, respectively.

After reviewing the regulatory options for the existing fiberboard mat dryer heated zones and press predryer, the EPA is proposing to set the HAP emission standards at the MACT floor. The more stringent beyond-the-floor options for each dryer were rejected because of the high costs relative to the HAP emission reduction that could be achieved, energy usage, and other non-air quality environmental impacts. Although the more stringent beyond-the-floor options are not being proposed, we are proposing to include a provision in 40 CFR 63.2240(d)(6) to allow for compliance with the more stringent limits in table 1B to subpart DDDD of 40 CFR part 63 in place of the proposed limits in table 1C to subpart DDDD of 40 CFR part 63.

5. Log Vats

Log vats are used to condition logs before they are cut into veneer or wood strands. Hot water vats in which logs are immersed are often open to the atmosphere. In log steaming or “chest” vats, logs are placed in the vat in batches, the door is closed, and steam (which condenses in the vat) along with hot water sprays are used to condition the logs for a specified time before the logs are removed for veneer production. Both types of vats heat logs to within the same temperature range (up to 230 °F based on ICR responses).

The recent ICR identified 81 log vats used at PCWP facilities, including 51 hot water vats and 30 chest vats. None of the log vats are controlled for HAP, have a conveyance for collection of emissions, or have a stack for emissions measurement. Because the log vats have neither the proper emissions capture and conveyance ductwork nor stacks where emissions testing could be conducted, based on CAA section 112(h)(2)(A) and (B), we are proposing a work practice standard for log vats at

existing or new sources. Although the HAP emissions data are not available to correlate with log temperature, it is reasonable to expect that overheating logs could increase the potential for HAP emissions from log vats. The proposed work practice standard would require facilities to: (a) operate each vat using a site-specific target log temperature that does not exceed 212 °F, measured in the water used to soak the logs or in the wood cut at the lathe or stranders; and (b) operate each vat to reduce the potential for fugitive emissions by either: (1) covering at least 80 percent of the vat hot water surface area for soaking vats in which logs are submerged; or (2) keeping doors closed while steam or hot water showers are being applied inside log steaming vats.

Initial and continuous compliance with the log vat work practice could be demonstrated through monitoring, recordkeeping, and reporting that reflects adherence to the work practice conditions. No regulatory options more stringent than the work practice were identified for further consideration for log vats. Nationwide organic HAP reductions are estimated to be 0.7 tpy for existing sources and 0.17 tpy for new sources.

6. Mixed PCWP Process Streams Regulated at Existing Sources

Some PCWP facilities route emission streams from multiple process units of the same or different types into 1 shared HAP control system such as an RTO, RCO, biofilter, or process incineration system to meet the compliance options in table 1B to subpart DDDD of 40 CFR part 63. In a few mixed process arrangements, an emissions stream from a remanded unit is mixed at the inlet to a HAP control device and co-controlled with other process units listed in table 1B such that the combined emission stream became subject to the table 1B limits when the control system was initially installed to meet the 2004 NESHAP or as part of the PCWP plant design. Due to commingling, emissions from each individual type of process unit contributing to a mixed PCWP process stream cannot be distinguished at the inlet or outlet of the control device. For this reason, we are proposing that mixed PCWP process streams from remanded units meeting the compliance options in table 1B be considered a separate type of emission stream that remains subject to the table 1B limits. Mixed PCWP process streams are proposed to be defined in 40 CFR 63.2292 as an emission stream from a process unit subject to the final amendments that was commingled with emissions stream(s) from process unit(s)

subject to the compliance options in table 1B to subpart DDDD of 40 CFR part 63 before the effective date of the final amendments at an affected source that commenced construction (or reconstruction) on or before the date of this proposal. The recommended definition of “mixed PCWP process stream” refers specifically to a “stream” as opposed to a whole process unit because there can be uncaptured or uncontrolled emissions from a remanded process unit in addition to the captured emission stream from the remanded unit that is routed to the HAP control device as part of a mixed PCWP process stream.

D. What MACT standards are we proposing for process units with MDI emissions?

The EPA is proposing standards to regulate MDI emissions from reconstituted wood products presses, tube dryers that blow-line blend MDI resin, and miscellaneous coating operations. The proposed standards for tube dryers that blow-line blend MDI resin would apply for commingled MDI emissions from tube dryers and reconstituted wood products presses using MDI. Supporting information for the proposed standards is provided in the memorandum, *Regulatory Options for MDI Emissions from Plywood and Composite Wood Products*, *Reconstituted Wood Products Presses, Tube Dryers, and Miscellaneous Coating Operations*, in the docket for this action.

1. Reconstituted Wood Products Presses

The EPA is proposing standards for MDI emissions from reconstituted wood products presses that use MDI resin at any time during the year in any portion of the board (e.g., whole board, core, or face). Emissions data for MDI are available from EPA Method 326 testing conducted in 2022 (in response to a CAA section 114 request) on presses using MDI throughout the whole board.

The EPA is proposing to distinguish reconstituted wood products presses that produce OSB from those producing particleboard or MDF (PB/MDF) for purposes of establishing MDI standards because product differences appear to affect MDI emissions. With the HAP control level being the same, product differences are expected to be the reason for the difference in MDI emissions. Particleboard and MDF are similar to one another in that they are used for the same interior product markets (e.g., cabinets, shelving, furniture) while OSB is used for exterior applications (e.g., siding, roofing). OSB furnish is made of flat wood strands (e.g., several inches in length) as opposed to the small wood

fibers used to manufacture MDF. The smaller wood fibers (or particles) used in MDF/PB presses have greater overall surface area than the much larger OSB wood strands per volume of board produced. The difference in wood furnish surface area that is coated with MDI resin can result in different potential for MDI emissions from PB/MDF presses compared to OSB presses. Different pressing temperatures are also used. Therefore, we are proposing to group the presses by product type to adequately address the variability in MDI emissions associated with different products.

There are 26 OSB presses that use MDI resin. The EPA has MDI emissions data for 2 of these presses using the type of control system considered to be best performing for reducing organic HAP emissions, including MDI. As noted previously, when there are fewer than 30 sources, the MACT floor is based on the best performing 5 sources. However, in this case emissions data are only available for 2 sources for determining the MACT floor. Using the MDI emissions data from 2 OSB presses, the MACT floor for existing sources was calculated and compared to the 3xRDL MDI concentration and OSB press emission rate values of 27 micrograms per dry standard cubic meter (ug/dscm) of air or 2.5E-04 lb/MSF $\frac{3}{4}$ " (1.3E-04 lb/MSF $\frac{3}{8}$ "). The 3xRDL values exceeded the MACT floor concentration and emission rate for existing sources and are therefore being proposed in place of the existing source MACT floor for OSB presses using MDI to ensure that the standards are established at the minimum level at which emissions can be measured reliably. The MDI MACT floor for new source OSB presses was calculated using the MDI emissions data for the best performing OSB press and compared to the 3xRDL MDI concentration. The 3xRDL values exceeded the MACT floor concentration and emission rate for new sources and are therefore being proposed in place of the new source MACT floor for OSB presses using MDI.

There are 10 PB/MDF presses that use MDI resin. The EPA has MDI emissions data for 2 of the PB/MDF presses with the type of control system considered to be best performing for reducing organic HAP emissions, including MDI. Using the MDI emissions data from the 2 PB/MDF presses, the MACT floor for existing sources was determined to be 8.4E-04 lb/MSF $\frac{3}{4}$ " or 200 ug/dscm, which is higher than the corresponding 3xRDL value. The MACT floor for new source PB/MDF presses was calculated based on the single best performing press and compared to the 3xRDL MDI

concentration and PB/MDF press emission rate values of 27 ug/dscm and 2.3E-04 lb/MSF $\frac{3}{4}$ ", respectively. The 3xRDL values exceeded the MACT floor concentration and emission rate and are therefore being proposed in place of the MACT floor for new source PB/MDF presses using MDI to ensure that the standards are established at the minimum level at which emissions can be measured reliably.

Estimated annual emissions of MDI from the reconstituted wood products presses tested were less than 0.1 ton/year. This low level of emissions is likely because MDI polymerizes into a solid rapidly and irreversibly in the reconstituted wood products press, and the presses tested are equipped with the types of organic HAP controls found on the best performing sources in the PCWP industry. Also, less than one hundredth of a percent (<0.01%) of the MDI applied was measured at the inlet or outlet of the control device. Considering the low levels of MDI emitted and that reconstituted wood products presses already meet HAP limits from the 2004 PCWP NESHAP using robust HAP controls, no regulatory options more stringent than the existing or new source MACT floors for MDI were identified for OSB or PB/MDF reconstituted wood products presses. Accordingly, we are proposing that the MDI MACT floors for existing and new OSB and PB/MDF reconstituted wood products presses is MACT for these process units.

Reconstituted wood products presses operating HAP controls are expected to meet the MACT floor for existing and new sources. However, it is currently unknown whether presses at 2 particleboard facilities that meet the PCWP production-based compliance option (PBCO)¹⁷ using pollution prevention measures would meet the MDI MACT floor. An MDI emission reduction of 0.077 tpy with corresponding VOC reduction of up to 63 tpy is estimated for existing sources. For new sources, no MDI or VOC emission reductions are estimated because new presses are expected to meet the new source limit.

2. Tube Dryers

Primary tube dryers often incorporate blow-line blending in which resin is added to wood fibers as they enter the primary tube dryer. The resin and wood fibers mix with the turbulent conditions in the primary tube dryer as the wood fiber is dried. Within the PCWP industry, 5 primary tube dryer systems

incorporate blow-line blending using MDI resin to produce MDF. In addition, 3 secondary tube dryer systems follow primary tube dryers that blow-line blend MDI resin. All of the primary and secondary tube dryer systems have air pollution controls to reduce organic HAP emissions to comply with the 2004 PCWP NESHAP standards.

Primary and secondary tube dryers are often co-controlled. In some systems, air flow from the secondary tube dryers vents through the primary tube dryers (for energy conservation), while in other systems the secondary tube dryers vent directly to the same air pollution control system as the primary tube dryers. All of the secondary tube dryers that follow primary tube dryers in which MDI is injected with a blow-line have emissions that exit from the same emission point as primary tube dryers. Therefore, the MDI emission limits developed for the primary tube dryers apply for secondary tube dryers as well.

Primary tube dryers may also be co-controlled with a reconstituted wood products press. Emissions data for MDI are available from the 2022 CAA section 114 survey testing for 1 MDI primary tube dryer system that blow-line blends MDI and is co-controlled with a press. Emissions from the dryer (including press emissions routed through the dryer) are controlled by an RTO. The inlet and outlet of the RTO were tested for MDI, in which an average MDI reduction of 87 percent was achieved. The inlet MDI concentration for the blow-line blend tube dryer (with press) system was higher than MDI emissions from reconstituted wood products presses alone, which suggests that most of the MDI emissions in a combined system are associated with the blow-line blend tube dryer. Therefore, we are proposing that the same MDI standard (in terms of lb/ODT) established for blow-line blend tube dryers alone would also apply for blow-line blend tube dryer and press combinations.

Because there are fewer than 30 primary tube dryers that blow-line blend MDI, according to CAA section 112(d), the MACT floor for existing sources is based on the best performing 5 systems for which the Administrator has emissions information and the MACT floor for new sources is based on the single best performing system. In this case, because emissions data are available for only 1 system, data for this 1 system was used to establish the MACT floor for both existing and new sources. Using the emission test run data for the tested dryer system (7 runs), the MACT floor for new and existing sources is 1.7E-02 lb/ODT or 0.68 mg/

¹⁷ Table 1A to subpart DDDD of 40 CFR part 63 contains the PBCO total HAP limits.

dscm. No regulatory options more stringent than the MACT floor were identified for tube dryers that blow-line blend MDI.

Because all of the tube dryer systems that blow-line blend MDI resin have HAP emission controls, we anticipate that they would all meet the MDI MACT floor based on the average MDI emissions from the comparable unit tested. No MDI emission reductions are estimated as all existing and new sources are expected to meet the MACT floor.

3. Miscellaneous Coatings Operations

The EPA is proposing to regulate MDI emissions from miscellaneous coating operations in which MDI moisture sealants are applied to engineered wood products such as parallel strand lumber or LVL. One MDI moisture sealant spray booth at an engineered wood products facility was identified and tested as part of the 2022 CAA section 114 survey. Using the test data from this facility, the proposed MACT floor limit for existing and new sources is 1.9E-03 lb MDI emitted/lb sealant applied, or 1.4E-05 lb MDI/ft² surface area coated based on coating HAP content. No reduction in MDI emissions is estimated as a result of the MDI MACT floor. No options more stringent than the MACT floor emission level were identified for further analysis.

E. What performance testing, monitoring, and recordkeeping and reporting are we proposing?

1. Performance Testing

For the new and existing source emission limits being added to the PCWP NESHAP, we are proposing that new sources demonstrate initial compliance within 180 days after the effective date of the final rule or after startup, whichever is later, and that existing sources demonstrate initial compliance within 3 years after promulgation of the final rule. Additionally, we are proposing that subsequent performance testing would be required every 5 years (60 months), using the methods identified in table 4 to subpart DDDD of 40 CFR part 63.

The proposed emissions test methods for total HAP include EPA Method 320 (40 CFR part 63, appendix A), NCASI Method IM/CAN/WP-99.02 (IBR in 40 CFR 63.14), NCASI Method ISS/FP-A105.0 (IBR in 40 CFR 63.14); or ASTM D6348-12e1 (IBR in 40 CFR 63.14) with the conditions discussed in section VIII.I of this preamble. EPA Method 326 (40 CFR part 63, appendix A) is proposed for MDI emissions measurement, in which a minimum

sample of 1 dry standard cubic meter (dscm) must be collected. For PM as a surrogate to HAP metals, either EPA Method 5 (40 CFR part 60, appendix A-3) or EPA Method 29 (40 CFR part 60, appendix A-8) is proposed with a minimum sample volume of 2 dscm. For Hg, EPA Method 29 or EPA Method 30B (40 CFR part 60, appendix A-8) are proposed, with a minimum sample volume of 2 dscm. The EPA Method 26A (40 CFR part 60, appendix A-8) is proposed for HCl emissions measurement with a minimum sample volume of 2 dscm. The recently updated EPA Method 23 (40 CFR part 60, appendix A-8) is proposed for PAH emission measurement with a minimum sample volume of 3 dscm. Consistent with the treatment of non-detect data used to establish the emission standards, we are proposing that non-detect data be treated as the MDL in test averages used to demonstrate compliance with the standards proposed in tables 1C, 1D, or 1E to subpart DDDD of 40 CFR part 63.

2. Parameter Monitoring

Under this proposal, continuous compliance with the standards proposed in tables 1C, 1D, or 1E to subpart DDDD of 40 CFR part 63 would be demonstrated through control device parameter monitoring coupled with periodic emissions testing described earlier in this preamble. The parametric monitoring already required in table 2 to subpart DDDD of 40 CFR part 63 for thermal oxidizers, catalytic oxidizers, or biofilters to demonstrate continuous compliance with the compliance options in table 1B to subpart DDDD of 40 CFR part 63 would also be required to demonstrate ongoing compliance with the standards in tables 1C, 1D, or 1E to subpart DDDD of 40 CFR part 63. In addition to the parametric monitoring currently specified for thermal oxidizers, catalytic oxidizers, or biofilters, we are proposing to add to table 2 to subpart DDDD of 40 CFR part 63 the following parameter monitoring requirements for the types of APCDs that we expect would be used to comply with the standards proposed in tables 1D or 1E to subpart DDDD of 40 CFR part 63:

- For WESP, monitor and record the secondary electric power input and liquid flow rate;
- For dry ESP, monitor and record the secondary electric power input or opacity;
- For wet PM scrubbers, monitor and record the liquid flow rate and pressure drop;

- For wet acid gas scrubbers, monitor and record the liquid flow rate and effluent pH;
- For electrified filter beds, monitor and record the ionizer voltage or current and pressure drop; and
- For mechanical collectors (e.g., cyclone or multiclone) or other dry control devices, monitor and record opacity.

The operating limits for these parameters are proposed to be set consistent with the existing provisions of 40 CFR 63.2262, as the average of the 3 test run averages during the performance test. Continuous compliance with the parameters for WESP, dry ESP, wet scrubbers, and EFB would be determined by comparing the 3-hour block average parameter average to the limit established during the performance test.

Consistent with existing provisions in table 2 to subpart DDDD of 40 CFR part 63, a source owner choosing to rely on a control device other than a thermal oxidizer, catalytic oxidizer, or biofilter used to meet a compliance option in table 1C to subpart DDDD of 40 CFR part 63 would be required to petition the Administrator for site-specific operating parameters to be monitored or would have to maintain the 3-hour block average THC concentration within the limits established during the performance test. The source owner of process units that meet a compliance option in table 1C, 1D, or 1E to subpart DDDD of 40 CFR part 63 without using a control device would be required to maintain on a daily basis the process unit controlling operating parameter(s) within the ranges established during the performance test or maintain the 3-hour block average THC concentration within the limits established during the performance test.

For control devices where opacity is used as an operating parameter, we are proposing that a continuous opacity monitoring system (COMS) would be used and that the 24-hour block average opacity must not exceed 10 percent (or the highest hourly average measured during the performance test). We are proposing updates to table 10 to subpart DDDD of 40 CFR part 63 to indicate provisions pertaining to opacity and COMS that apply for subpart DDDD. We are proposing to change the following provisions from “No” or “NA” to “Yes” in table 10: 40 CFR 63.8(c)(5), 63.8(e), 63.9(f), and 63.10(e)(4). We are also proposing to note in table 10 that the requirements for opacity standards in 40 CFR 63.6(h)(2) through (9) do not apply because the opacity is being proposed as an operating limit and not as an emission standard.

Continuous monitoring requirements associated with the work practices proposed in table 3 to subpart DDDD of 40 CFR part 63 include combustion unit bypass stack usage monitoring (*e.g.*, temperature or bypass damper position), lumber kiln dry bulb temperature monitoring (for comparison of the 3-hour block average to the dry bulb set point), in-kiln lumber moisture monitoring (for comparison of the semiannual average kiln-dried lumber moisture content), or monitoring of lumber kiln temperature (with 3-hour block averaging) and lumber moisture (with semiannual averaging) for comparison to limits in an approved site-specific plan.

We are also proposing continuous monitoring and recording of process unit bypass stack usage at all times while the process units are operating, including times when the process unit is undergoing startup or shutdown, and during the operating conditions specified in 40 CFR 63.2250(f)(2) through (4). This requirement is being proposed to ensure that reliable data are available to evaluate continuous compliance with the PCWP NESHAP requirements.

Consistent with NESHAP general provisions, a source owner would be required to operate and maintain the source, its air pollution control equipment, and its monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, to include operating and maintaining equipment in accordance with the manufacturer's recommendations. Owners would be required to prepare and keep records of calibration and accuracy checks of the continuous monitoring system (CMS) to document proper operation and maintenance of the monitoring system.

3. Recordkeeping and Reporting

Under this proposal, and consistent with existing requirements in the PCWP NESHAP, a source owner would be required to submit semi-annual compliance summary reports which document both compliance with the requirements of the PCWP NESHAP and any deviations from compliance with any of those requirements. Owners and operators would be required to maintain the records specified by 40 CFR 63.10 and, in addition, would be required to maintain records of all monitoring data, in accordance with the PCWP NESHAP (40 CFR 63.2282).

F. What other actions are we proposing, and what is the rationale for those actions?

In addition to proposing the new standards and monitoring, recordkeeping and reporting requirements discussed above, we are proposing to revise the PCWP NESHAP to remove obsolete rule language including the emissions averaging compliance option, dates, and startup/shutdown provisions that are no longer in effect. Removing the outdated language from the PCWP NESHAP would streamline the rule and make it easier to read. We are also proposing updates and clarifications of the electronic reporting requirements. The proposed revisions and rationale are presented below.

1. Emissions Averaging

Emissions averaging was included in the 2004 rule as a compliance option for use at existing affected sources. To date, the EPA is only aware of one facility that used the emissions averaging compliance option, but that facility has ceased PCWP production. We are proposing to remove the emissions averaging compliance option because no existing facilities are using it, and emissions averaging is not an option for new affected facilities. Also, the proposed new emission standards discussed in section IV of this preamble further diminish opportunities for emissions averaging. Our proposal to remove the emissions averaging option would simplify the rule language.

2. Obsolete Dates and Provisions

On August 13, 2020, the EPA published several amendments to the PCWP NESHAP that were effective on August 13, 2020. The amendments included removal of references to the SSM exemption in 40 CFR 63.6(f)(1) and (h)(1) and changes to certain recordkeeping and reporting provisions. The compliance dates for the August 13, 2020, amendments were August 13, 2020, for affected sources that commenced construction or reconstruction after September 19, 2019, or August 31, 2021, for all other affected sources. Those compliance dates have passed.

The amendments now being proposed would become effective on the date of publication of the final rule and would have multiple associated compliance dates as discussed in section IV.G of this preamble. To reduce confusion as we add future compliance dates to the PCWP NESHAP, we are proposing to remove the obsolete dates and

provisions that are no longer in effect, including:

- In 40 CFR 63.2233(1) through (3), cross-references to specific paragraphs needed to implement the August 13, 2020, amendments are proposed to be removed and replaced with a reference to the proposed 40 CFR 63.2233(e), which provides compliance dates for the rule requirements proposed in this action.
 - Paragraphs 40 CFR 63.2250(a) through (c) are proposed to be removed and reserved because their requirements no longer apply.
 - Date language is proposed to be removed in paragraphs 40 CFR 63.2250(f) and (g), which are paragraphs that replaced the obsolete paragraphs 40 CFR 63.2250(a) through (c) in the August 13, 2020, amendments.
 - Paragraphs 40 CFR 63.2280(b) and (d) contained dates for when electronic submittal of initial notifications and performance test results became effective. 40 CFR 63.2281(b)(6) contained dates for when electronic submittal of semiannual reports became effective. These dates have passed, and the electronic reporting requirements are in full effect, so we are proposing to remove dates to make the rule easier to read.
 - The first part of paragraph 40 CFR 63.2281(c)(4) contains dates for language that was phased out as well as dates for when electronic reporting requirements were phased in. Similarly, 40 CFR 63.2282(a)(2) contains obsolete dates and language intended to phase out some records and phase in other records. Because the dates have now passed, we are proposing to remove the obsolete language to simplify the rule.
 - Row 2 in table 9 to subpart DDDD of 40 CFR part 63 is proposed to be removed and reserved because the requirement for an SSM report is no longer in effect.
 - The August 13, 2020, final rule added a column to table 10 to subpart DDDD of 40 CFR part 63 to clarify which general provisions in subpart A of 40 CFR part 63 applied before and after August 13, 2021, for existing sources. The now obsolete column pertaining to requirements before August 13, 2021, is proposed to be removed.
- Those amendments pertain to SSM provisions that have been removed and to reporting provisions that were added on August 13, 2020. For clarity, we are retaining date language from the August 13, 2020, final rule that specified compliance dates for standards and electronic reporting provisions added with that rulemaking. We have also taken care to insert compliance date

language for the new standards proposed in this action (in 40 CFR 63.2240(d) and (e), tables 1C, 1D, 1E to subpart DDDD of 40 CFR part 63, 40 CFR 63.2241(d) through (h), and table 3 to subpart DDDD of 40 CFR part 63) as discussed further in section IV.G of this preamble.

3. Electronic Reporting Updates and Clarifications

On November 19, 2020, the EPA published a final rule incorporating standard electronic reporting language into the general provisions at 40 CFR 63.9(k). In this action, we are proposing to update the electronic reporting language in 40 CFR part 63, subpart DDDD, to refer to the provisions in 40 CFR 63.9(k) in addition to other revisions. The proposed revisions are as follows:

- We are proposing to require that initial notifications and notifications of compliance status be submitted in a user-specified format such as portable document format (PDF) in 40 CFR 63.2280(b) and (d) instead of 40 CFR 63.2281(h).

- General provisions pertaining to submittal of CBI are proposed to be removed from 40 CFR 63.2281(h), (i)(3), and (j)(3).

- In 40 CFR 63.2281(k), we are proposing to replace language pertaining to CEDRI outages (which is now in 40 CFR 63.9(k)) with additional detailed procedures for submitting CBI in electronic format. The update provides an email address that source owners and operators can use to electronically mail CBI to the OAQPS CBI Office when submitting compliance reports.

- In 40 CFR 63.2281(l), we are proposing to remove the provisions related to force majeure claims which are now in 40 CFR 63.9(k).

- We are proposing to remove the provision in 40 CFR 63.2283(d) that states that records submitted to CEDRI may be maintained in electronic format, because 40 CFR 63.10(b)(1) already allows the retention of all records electronically.

- In table 10 to subpart DDDD of 40 CFR part 63, we are proposing to indicate that all of the provisions in 40 CFR 63.9(k) apply to 40 CFR part 63, subpart DDDD.

In addition, we are proposing to amend 40 CFR 63.2281(c)(4) to clarify the compliance reporting requirements for the work practices in table 3 to subpart DDDD of 40 CFR part 63 (rows 6, 7, or 8). We are proposing to clarify that the requirement to report the date, time, and duration of every instance in which one of the work practices is used

applies only if that individual work practice is used for more than 100 hours during the reporting period. The EPA's original intent was for the 100-hour reporting threshold to be compared to the semiannual usage of each of the 3 work practices individually, not for the total usage of all 3 work practices combined. As stated in 40 CFR 63.2281(c)(4), when one of the work practices is used for less than 100 hours per semiannual reporting period, a summary of the number of instances and total amount of time that work practice was used is required to be reported. As noted previously, we are also proposing to require continuous monitoring and recording of process unit bypass stack usage at all times including during the operating conditions specified in 40 CFR 63.2250(f)(2) through (4) and table 3 to subpart DDDD of 40 CFR part 63 (rows 6, 7, or 8) to ensure that reliable data are available to evaluate continuous compliance with the PCWP NESHAP requirements.

Finally, we are placing in the docket a revised draft version of the PCWP semiannual reporting template with updates to reflect the proposed changes to 40 CFR part 63, subpart DDDD, described throughout this preamble.

4. Definitions and Other Amendments

We are proposing to add several definitions to the PCWP NESHAP to define process units with new standards being added to the rule. We are also proposing to amend selected existing definitions to ensure that the products and process units covered by the PCWP NESHAP are adequately described.

5. Issues Raised by Petitioners Following the RTR

Following publication of the final RTR (85 FR 49434, August 13, 2020), the EPA received a petition for reconsideration (Petition) from Earthjustice on behalf of Greater Birmingham Alliance to Stop Pollution, Louisiana Environmental Action Network, and Sierra Club (Petitioners). The Petitioners asked the EPA to reconsider certain aspects of the August 13, 2020, final technology review and other amendments under the authority of CAA section 307(d)(7)(B), arguing that the EPA's rationale for four decisions all appeared for the first time in the 2020 final rule and response to comments (RTC) document accompanying the final rule.¹⁸ The EPA

is proposing changes to the PCWP NESHAP to address some of the Petitioners' concerns and is inviting public comment on some of the issues raised by the Petitioners in their letter to the EPA, which is available in the docket for this action.¹⁹ The four issues are discussed below.

In the first issue raised, the Petitioners alleged that the EPA failed to set limits for unregulated HAPs. Although we do not agree that the Petitioners have met their burden under CAA section 307(d)(7)(B) to show that it was impracticable to raise this objection during the public comment period for the proposed 2020 technology review, and thereby compel reconsideration of this issue, this action contains proposed standards for unregulated HAP in order to respond to the 2007 partial remand and vacatur of the 2004 NESHAP and to comport with the 2020 *LEAN* ruling, such that the Petitioners' concern regarding this issue will be resolved once this action is finalized.

In the second and third issues raised by the Petitioners, they disagreed with two work practices the EPA finalized on the August 13, 2020, for safety-related shutdowns and pressurized refiner startup and shutdown and objected to what they perceived to be the EPA's changed or new rationale for these work practices, claiming that they did not have an opportunity to raise their objections during the public comment period. The Petitioners disagreed with the EPA's use of CAA section 112(h) to develop work practice standards for safety-related shutdowns and pressurized refiner startup and shutdown events. For safety-related shutdowns, the Petitioners took issue with the EPA's rationale that facilities cannot capture and convey HAP emissions *to a control device* during these periods for safety reasons (RTC at 89, emphasis added), saying that whether emissions can be conveyed *to a control device* is irrelevant under CAA section 112(h)(2)(A). In response to this critique, and to ensure that there is a full opportunity for all stakeholders to comment on the EPA's rationale for these work practices, the EPA requests comment on the relevance of the ability of facilities to capture and convey emissions to a control device to CAA

2019, Proposal. Document ID No. EPA-HQ-OAR-2016-0243-0244 in the docket for this action.

¹⁹ Letter from J. Pew, Earthjustice, to A. Wheeler, EPA. Petition for reconsideration of the final action taken at 85 FR 49434 (August 13, 2020), titled "National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products Residual Risk and Technology Review submitted on behalf of Greater Birmingham Alliance to Stop Pollution, Louisiana Environmental Action Network, and Sierra Club." October 13, 2020.

¹⁸ National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products (40 CFR part 63, subpart DDDD) Residual Risk and Technology Review, Final Amendments, Responses to Public Comments on September 6,

section 112(h)(2)(A), given that CAA section 112(h)(2)(A) explicates CAA section 112(h)(1) which explicitly refers to the EPA's judgment as to when it is not feasible to prescribe or enforce an emission standard *for control of* a HAP (emphasis added).

Regarding the EPA's rationale under CAA section 112(h)(2)(B) for the safety-related shutdown and pressurized refiner startup and shutdown work practices, the Petitioners expressed discontent with the EPA's conclusion that stack tests (which typically take 1 to 3 hours) cannot be conducted for events lasting only minutes. The Petitioners asserted that EPA should have considered the practicability of other measurement methodologies including CEMS or continuous parameter monitoring. In response to the Petitioners' concerns, we maintain that stack testing is not feasible for safety-related shutdown events lasting only minutes or for pressurized refiner startup/shutdown events lasting less than 15 minutes. We request comment on how the EPA could feasibly prescribe or enforce a numeric emission limit for such short-term events without the ability to conduct stack testing. Further, continuous operation of CEMS on bypass stacks that are unused for the majority of process operating time is not practicable from an economic standpoint or technically (e.g., because of the calibration drift likely to occur while the CEMS goes unused). The source testing required for conducting a RATA of CEMS would not be possible without requiring the use of the bypass during the RATA. Obtaining emissions data to correlate with parameters to establish continuously monitored parameter limits also necessitates stack testing. Although CEMS or specific continuously monitored parameter limits are not an appropriate measurement methodology for safety-related shutdowns and pressurized refiner startups and shutdowns themselves because of technical and economic limitations, we are proposing additional continuous parameter monitoring of bypass stack usage in addition to the work practices for safety-related shutdowns and pressurized refiner startup/shutdown events to address the Petitioners' concern. As discussed in section IV.A.6 of this preamble, we are proposing to require continuous monitoring of combustion unit bypass stacks in addition to proposing standards for annual tune-ups of combustion units used to direct-fire dryers. As discussed in section IV.E.2 of this preamble, we are also proposing continuous monitoring of process unit

bypass stack usage at all times while the process units are operating, including times when the process unit is undergoing startup or shutdown, and during safety-related shutdowns and pressurized refiner startup/shutdown events to ensure that reliable data are available to evaluate continuous compliance with the PCWP NESHAP requirements.

The Petitioners also took issue with inclusion of measures that facilities have developed to protect workers and equipment in the safety-related shutdown work practice. The Petitioners argued that the steps an operator takes to protect workers and equipment are not necessarily the steps needed to prevent excess emissions or to remove raw materials and the heat source from the process as expeditiously as possible. We disagree with the Petitioners that the phrase "to protect workers and equipment" detracts from the safety-related shutdown work practice requirements to ensure that the flow of raw materials (such as furnish or resin) and fuel or process heat (as applicable) ceases and that material is removed from the process unit(s) as expeditiously as possible given the system design to reduce air emissions. However, we request comment on inclusion of measures facilities developed to protect workers and equipment from the safety-related shutdown provision. We also request comment on all aspects of the work practice provisions (which appear in table 3 to subpart DDDD of 40 CFR part 63, rows 6 and 7) based on operational experience now that these narrowly defined provisions have been implemented in place of the broader SSM exemptions that were removed from the PCWP NESHAP.

In their fourth issue raised, the Petitioners disagreed with the EPA's statement that use of low-HAP resins is a development under CAA section 112(d)(6), claiming that the EPA must revise standards for any development identified to require the maximum degree of reduction that is achievable through its application. In the 2020 technology review, when noting that low-HAP resins were a development, the EPA also explained that the EPA did not identify information to suggest that the resin system changes have significantly altered the type of process units or HAP pollution control technologies used in the PCWP industry to date or have led to processes or practices that have not been accounted for in the promulgated PCWP NESHAP compliance options. The Petitioners dismissed as irrelevant the EPA's explanation that there are many types of

resin systems used in the manufacture of the various PCWP and that the resin-system solution for one facility's product may not be applicable for another product produced at a different facility. The Petitioners also argued that it is irrelevant that the EPA noted in 2020 plans for additional action for the PCWP NESHAP source category with respect to remanded PCWP process units in which the EPA would further consider the effects of resin system changes.

Given the Petitioners' objections, we are rearticulating our conclusion from the August 13, 2020, final technology review. Specifically, we are retracting our characterization of low-HAP resins as a "development" under CAA section 112(d)(6) with respect to the standards established for the PCWP source category in 2004. As noted in 2020, the EPA did not identify information suggesting that the resin system changes have significantly altered the type of process units or HAP pollution control technologies used in the PCWP industry or have led to processes or practices that were not accounted for in the 2004 promulgated PCWP NESHAP compliance options. Therefore, we agree with the Petitioners that it may have been inappropriate to describe resin changes as a "development" under CAA section 112(d)(6) since the 2004 promulgated standards. Moreover, we disagree with the Petitioners' claim that if resin changes were in fact such a "development," the EPA would be required to establish MACT standards under CAA section 112(d)(2) and (3) as a consequence of that development. CAA section 112(d)(6) does not require the EPA to reconduct MACT determinations, as the D.C. Circuit made clear in *NRDC v. EPA*, 529 F.3d 1077 (D.C. Cir. 2008). Instead, CAA section 112(d)(6) provides that the EPA is to exercise its judgment to determine what revisions to preexisting standards are necessary, after considering such developments. In any event, as discussed in section IV.C.1 of this preamble, in this action—in order to address previously unregulated HAP emissions, respond to the 2007 partial remand and vacatur of the 2004 NESHAP, and comport with the *LEAN* ruling—we are under CAA section 112(h) setting standards for RMH process units for which no emission standards are currently in place, based on the use of non-HAP resins or resins with low vapor pressure (and therefore low potential for HAP emissions) including resin types which were available at the time of the 2004 rule.

G. What compliance dates are we proposing, and what is the rationale for the proposed compliance dates?

Amendments to the PCWP NESHAP proposed in this rulemaking for adoption under CAA section 112(d)(2) and (3) are subject to the compliance deadlines outlined in the CAA under CAA section 112(i). For existing sources, CAA section 112(i)(3) provides that there shall be compliance “as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard” subject to certain exemptions further detailed in the statute.²⁰ In determining what compliance period is as “expeditious as practicable,” we consider the amount of time needed to plan and construct projects and change operating procedures. As provided in CAA section 112(i), all new affected sources would comply with these provisions by the effective date of the final amendments to the PCWP NESHAP or upon startup, whichever is later.

The EPA projects that many existing sources would need to make changes (e.g., review operations, assemble documentation, install add-on controls and monitoring equipment) to comply with the proposed limits for various process units in their facility. These sources would require time to develop plans, construct, conduct performance testing, and implement monitoring to comply with the revised provisions. Therefore, we are proposing to allow 3 years for existing sources to become compliant with the new emission standards.

All affected facilities would have to continue to meet the current provisions of 40 CFR part 63, subpart DDDD, until the applicable compliance date of the amended rule.

For all affected sources that commence construction or reconstruction on or before May 18, 2023, we are proposing that it is necessary to provide 3 years after the effective date of the final rule for owners and operators to comply with the provisions of this action. For all affected sources that commenced construction or reconstruction after May 18, 2023, we are proposing that owners and operators comply with the provisions by the effective date of the final rule (or upon

startup, whichever is later). The effective date is the date of publication of the final amendments in the **Federal Register**.

As noted previously, the affected source is the collection of process units at a PCWP facility. Examples of new affected sources are new greenfield PCWP or lumber facilities, existing facilities constructing new PCWP manufacturing process lines in addition to (or as a replacement for) existing process lines, and existing lumber facilities adding (or replacing) lumber kilns in projects that meet the definition of reconstruction.

We solicit comment on these proposed compliance periods, and we specifically request submission of information from sources in this source category regarding specific actions that would need to be undertaken to comply with the proposed amended provisions and the time needed to make the adjustments for compliance with any of the revised provisions. We note that information provided may result in changes to the proposed compliance dates.

V. Summary of Cost, Environmental, and Economic Impacts

A. What are the affected sources?

There are currently 223 major-source facilities subject to the PCWP NESHAP. We estimate that 6 new PCWP facilities will be constructed and become subject to the NESHAP in the next 5 years.

B. What are the air quality impacts?

This proposed action is expected to reduce HAP and VOC emissions from the PCWP source category. In comparison to baseline emissions of 7,474 tpy HAP and 55,349 tpy VOC,²¹ the EPA estimates HAP and VOC emission reductions of approximately 591 tpy and 8,051 tpy, respectively. We also estimate that the proposed action would result in additional reductions of 231 tpy of PM, 164 tpy of PM_{2.5}, 132 tpy of NO_x, 718 tpy of CO, 12 tpy of SO₂, 129,741 tpy of CO₂, 11 tpy of methane (CH₄), and 4.7 tpy of nitrous oxide (N₂O). The reduction in CO₂, CH₄, and N₂O combined is also equal to 130,455 carbon dioxide equivalent (CO₂e).

Secondary air impacts associated with the proposed action are estimated to result in emissions increases of 5.4 tpy of PM, 2.0 tpy of PM_{2.5}, 22 tpy of CO,

2.7E–04 tpy of Hg, 14 tpy of NO_x, 14 tpy of SO₂, 23,227 tpy CO₂, 1.8 tpy of CH₄, and 0.26 tpy of N₂O. The increase in the CO₂, CH₄, and N₂O is also equal to 23,350 CO₂e. More information about the estimated emission reductions and secondary impacts of this proposed action can be found in the document *Cost, Environmental, and Energy Impacts of Subpart DDDD Regulatory Options* in EPA Docket ID No. EPA–HQ–OAR–2016–0243.

C. What are the cost impacts?

The EPA estimates that this proposed action would cost approximately \$126 million in total capital costs (distributed across multiple years) and \$51 million per year (in 2021 dollars) in total annualized costs. More information about the estimated cost of this proposed action can be found in the document *Cost, Environmental, and Energy Impacts of Subpart DDDD Regulatory Options* contained in the docket for this action.

D. What are the economic impacts?

For the proposed rule, the EPA estimated the cost of compliance with the proposed emission limits. This includes the capital costs of installation, and subsequent maintenance and operation of the controls as well as other one-time and annual costs. To assess the potential economic impacts, the expected annual cost was compared to the total sales revenue for the ultimate owners of affected facilities. For this rule, the expected annual cost is \$228,700 (on average) for each facility, with an estimated nationwide annual cost of \$51,000,000. The 223 affected facilities are owned by 65 parent companies, and the total costs associated with the proposed amendments are expected to be on average about 0.2 percent of annual sales revenue per ultimate owner.

Information on our cost and economic impact estimates for the PCWP manufacturing source category is available in the docket for this proposed rule (Docket ID No EPA–HQ–OAR–2016–0243).

E. What are the benefits?

Implementing the proposed amendments is expected to reduce emissions of HAP and non-HAP pollutants, such as VOC. In this section, we provide a qualitative discussion of the benefits of this proposed rule and HAP health effects.

²⁰ *Association of Battery Recyclers v. EPA*, 716 F.3d 667, 672 (D.C. Cir. 2013) (“Section 112(i)(3)’s 3-year maximum compliance period applies generally to any emission standard . . . promulgated under [section 112]” (brackets in original)).

²¹ Baseline emissions are from uncontrolled process units; i.e., they do not include emissions from process units regulated by the NESHAP.

We estimate that the proposed amendments would reduce HAP emissions from the source category by approximately 591 tpy. The amendments would regulate emissions of acetaldehyde, acrolein, formaldehyde, methanol, phenol, propionaldehyde, non-Hg HAP metals, Hg, HCl, PAH, D/F and MDI. Information regarding the health effects of these compounds can be found in *Health Effects Notebook for Hazardous Air Pollutants* (at <https://www.epa.gov/haps/health-effects-notebook-hazardous-air-pollutants>) and in the EPA Integrated Risk Information System (IRIS) database (at https://iris.epa.gov/AtoZ/?list_type=alpha).

The proposed amendments would reduce emissions of VOC which, in conjunction with NO_x and in the presence of sunlight, form ground-level ozone (O₃). There are health benefits of reducing VOC emissions in terms of the number and value of avoided ozone-attributable deaths and illnesses. The *Integrated Science Assessment for Ozone* (Ozone ISA)²² as summarized in the TSD for the Final Revised Cross State Air Pollution Rule Update²³ synthesizes the toxicological, clinical, and epidemiological evidence to determine whether each pollutant is causally related to an array of adverse human health outcomes associated with either acute (*i.e.*, hours or days-long) or chronic (*i.e.*, years-long) exposure. For each outcome, the ISA reports this relationship to be causal, likely to be causal, suggestive of a causal relationship, inadequate to infer a causal relationship, or not likely to be a causal relationship.

In brief, the Ozone ISA found short-term (less than 1 month) exposures to ozone to be causally related to respiratory effects, a “likely to be causal” relationship with metabolic effects and a “suggestive of, but not sufficient to infer, a causal relationship” for central nervous system effects, cardiovascular effects, and total mortality. The ISA reported that long-term exposures (1 month or longer) to ozone are “likely to be causal” for respiratory effects including respiratory mortality, and a “suggestive of, but not

sufficient to infer, a causal relationship” for cardiovascular effects, reproductive effects, central nervous system effects, metabolic effects, and total mortality.

F. What analysis of environmental justice did we conduct?

Following the directives set forth in multiple Executive orders, the Agency has evaluated the impacts of this action on communities with EJ concerns. Executive Order 12898 directs the EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms—specifically, minority populations (*i.e.*, people of color and/or Indigenous peoples) and low-income populations (59 FR 7629; February 16, 1994). Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through Federal Government actions (86 FR 7009; January 25, 2021).

The EPA defines EJ 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.²⁴ The EPA further defines fair treatment to mean that no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies. In recognizing that people of color and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

To examine the potential for any EJ issues that might be associated with PCWP manufacturing facilities, we performed a demographic analysis, which is an assessment of individual demographic groups of the populations living within 5 kilometers (km) and 50 km of the facilities. The EPA then compared the data from this analysis to the national average for each of the demographic groups.

The results of the demographic analysis (see table 1 of this preamble) indicate that the population percentages for certain demographic groups within 5 km of the 223 facilities are greater than the corresponding nationwide percentages. The demographic percentage for populations residing within 5 km of facility operations is 9

percentage points greater than its corresponding nationwide percentage for the African American population (21 percent within 5 km of the facilities compared to 12 percent nationwide), 7 percentage points greater than its corresponding nationwide percentage for the population living below the poverty level (20 percent within 5 km of the facilities compared to 13 percent nationwide), and 2 percentage points greater than its corresponding nationwide percentage for the population 25 years old and older without a high school diploma (14 percent within 5 km of the facilities compared to 12 percent nationwide). The remaining demographic groups within 5 km of facility operations are less than, or within one percentage point of, the corresponding nationwide percentages. It should be noted that, the average percent of the population that is Native American living within 5 km of the 223 facilities is 1.1 percent, which is over 1.5 times the national average. This is largely driven by populations living within 5 km of 16 facilities where the percent Native American population is over 5 times the national average.

These facilities are located in Washington (3 facilities), Oklahoma (4 facilities), Texas, Louisiana, South Dakota, Wisconsin, Minnesota, Oregon, Maine, Florida, and South Carolina.

In addition, the proximity results presented in table 1 of this preamble indicate that the population percentages for certain demographic groups within 50 km of the 223 facilities are greater than the corresponding nationwide percentages. The demographic percentage for populations residing within 50 km of the facility operations is 7 percentage points greater than its corresponding nationwide percentage for the African American population (19 percent within 50 km to the facilities compared to 12 percent nationwide), and 3 percentage points greater than its corresponding nationwide percentage for the population living below the poverty level (16 percent within 50 km of the facilities compared to 13 percent nationwide). The remaining demographic percentages within 50 km of the facilities are less than, or within one percentage point of, the corresponding nationwide percentages.

A summary of the proximity demographic assessment performed for the major source PCWP manufacturing facilities is included as table 1 of this preamble. The methodology and the results of the demographic analysis are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near PCWP Manufacturing Facilities*, available in this docket for

²² U.S. EPA. 2020. *Integrated Science Assessment for Ozone and Related Photochemical Oxidants*. U.S. Environmental Protection Agency. Washington, DC. Office of Research and Development. EPA/600/R-20/012. Available at: <https://www.epa.gov/isa/integrated-science-assessment-isa-ozone-and-related-photochemical-oxidants>.

²³ U.S. EPA. 2021. *Regulatory Impact Analysis Final Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*. Available at https://www.epa.gov/sites/default/files/2021-03/documents/revised_csapr_update_ria_final.pdf.

²⁴ <https://www.epa.gov/environmentaljustice>.

this action (Docket ID EPA-HQ-OAR-2016-0243).

TABLE 1—PROXIMITY DEMOGRAPHIC ASSESSMENT RESULTS FOR MAJOR SOURCE PCWP MANUFACTURING FACILITIES

Demographic group	Nationwide	Population within 50 km of 223 facilities	Population within 5 km of 223 facilities
Total Population	328,016,242	34,271,452	1,554,465
Race and Ethnicity by Percent			
White	60	66	65
African American	12	19	21
Native American	0.7	0.7	1.1
Hispanic or Latino (includes white and nonwhite)	19	8	9
Other and Multiracial	8	6	4
Income by Percent			
Below Poverty Level	13	16	20
Above Poverty Level	87	84	80
Education by Percent			
Over 25 and Without a High School Diploma	12	13	14
Over 25 and With a High School Diploma	88	87	86
Linguistically Isolated by Percent			
Linguistically Isolated	5	2	2

Notes:

• The nationwide population count and all demographic percentages are based on the U.S. Census Bureau's 2015–2019 American Community Survey 5-year block group averages and include Puerto Rico. Demographic percentages based on different averages may differ. The total population counts within 5 km and 50 km of all facilities are based on the 2010 Decennial Census block populations.

• Minority population is the total population minus the white population.

• To avoid double counting, the “Hispanic or Latino” category is treated as a distinct demographic category for these analyses. A person is identified as 1 of 5 racial/ethnic categories: White, African American, Native American, Other and Multiracial, or Hispanic/Latino. A person who identifies as Hispanic or Latino is counted as Hispanic/Latino for this analysis, regardless of what race this person may have also identified as in the Census.

The human health risk estimated for this source category for the August 13, 2020, RTR (85 FR 49434) was determined to be acceptable, and the standards were determined to provide an ample margin of safety to protect public health. Specifically, the maximum individual cancer risk was 30-in-1 million for actual and allowable emissions and the noncancer hazard indices for chronic exposure were below 1 (*i.e.*, 0.8 for actual and allowable emissions). The maximum noncancer hazard quotient for acute exposure was 4. These health risk estimates were based on HAP emissions from the source category after addition of air pollution controls used to meet the MACT standards promulgated in 2004, as well as the baseline HAP emissions from process units for which standards are being proposed in this action. While the August 13, 2020, amendments to 40 CFR part 63, subpart DDDD, reduced emissions by an unquantified amount by removing the startup, shutdown, and malfunction exemption and adding repeat testing requirements, the proposed changes to 40 CFR part 63, subpart DDDD, in this action would

reduce emissions by an additional 591 tons of HAP per year and therefore would further improve human health exposures for populations in all demographic groups. The proposed changes would have beneficial effects on air quality and public health for populations exposed to emissions from PCWP manufacturing facilities.

VI. Request for Comments

We solicit comments on this proposed action. In addition to general comments on this proposed action, we are also interested in additional data that may improve the analyses. If additional HAP performance test results are submitted, such data should include supporting documentation in sufficient detail to allow characterization of the quality and representativeness of the data or information.

For lumber kilns, we request comment on our proposed conclusions with respect to feasibility of capturing and measuring emissions from lumber kilns and our conclusions with respect to applicability of add-on controls for lumber kilns. We request comments on the proposed standards, including the

proposed O&M plan with its requirement for annual inspections in 40 CFR 63.2241(e)(1), proposed requirement for annual lumber kiln burner tune-ups in 40 CFR 63.2241(e)(2), and the proposed minimum kiln-dried lumber moisture content limits below which lumber is considered over-dried lumber for purposes of the PCWP NESHAP in 40 CFR 63.2241(e)(4). With respect to the work practice proposed in 40 CFR 63.2241(e)(3), we request comment on the utility and provisions for each of the 3 options (temperature set point, in-kiln lumber moisture monitoring, or site-specific plan).

For RMH units, we request comments on the work practices proposed for RMH process units, including comments pertaining to the procedures for demonstrating compliance with the requirement to use non-HAP resin or resin meeting the proposed maximum true vapor pressure limit and the requirement to process dried wood. We also request comment on other potential approaches for establishing standards for RMH process units considering that the RMH process units are not designed

and constructed in a way that allows for HAP emissions capture or measurement.

VII. Submitting Data Corrections

The site-specific emissions data used in setting MACT standards for PM (non-Hg HAP metals), Hg, acid gases, and PAH, as emitted from the PCWP source category, are provided in the docket (Docket ID No. EPA-HQ-OAR-2016-0243). If you believe that the data are not representative or are inaccurate, please identify the data in question, provide your reason for concern, and provide any “improved” data that you have, if available. When you submit data, we request that you provide documentation of the basis for the revised values to support your suggested changes. For information on how to submit comments, including the submittal of data corrections, refer to the instructions provided in the introduction of this preamble.

VIII. 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 not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 1984.11. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

We are proposing changes to the reporting and recordkeeping requirements for the PCWP NESHAP by incorporating the reporting and recordkeeping requirements associated with the MACT standards being added to the rule for multiple HAP from new and existing process units.

Respondents/affected entities: Owners or operators of PCWP or kiln-dried lumber manufacturing plants that are major sources, or that are located at, or are part of, major sources of HAP emissions.

Respondent's obligation to respond: Mandatory (40 CFR part 63, subpart DDDD).

Estimated number of respondents: On average over the next 3 years,

approximately 223 existing major sources would be subject to these standards. It is also estimated that 6 additional respondents would become subject to the emission standards over the 3-year period.

Frequency of response: The frequency of responses varies depending on the burden item (e.g., one-time, semiannual, annual, every 5 years).

Total estimated burden: The average annual burden to industry over the next 3 years from the proposed recordkeeping and reporting requirements is estimated to be 46,900 hours per year. Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: The total annual recordkeeping and reporting cost for all facilities to comply with all of the requirements in the NESHAP, including the requirements in this proposed rule, is estimated to be \$9,720,000 per year including \$4,020,000 in annualized capital and O&M 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 <https://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 July 17, 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. The small entities subject to the requirements of this action are small businesses, including one small business owned by a tribal government, as defined by the U.S. Small Business Administration (SBA). The EPA prepared a small business screening analysis to determine if any of the identified affected entities are small entities, as defined by the SBA. This analysis is available in the Docket for this action (Docket ID No. EPA-HQ-OAR-2016-0243). The Agency has

determined that 21 small ultimate PCWP manufacturing parent companies out of 65 may experience an impact from less than 0.01 percent to 1.94 percent of annual sales, with only 2 out of these 21 ultimate parent companies experiencing an impact of more than 1 percent of annual sales. Because the total annualized costs associated with the proposed amendments are expected to be more than 1 percent of annual sales revenue for only 2 small business ultimate parent owners in the PCWP manufacturing source category, there are, therefore, no significant economic impacts from these proposed amendments on the 27 affected facilities that are owned by 21 affected small ultimate parent entities.

Details of this analysis are presented in *Economic Impact and Small Business Screening Assessments for Proposed Amendments to the National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing Facilities*, located in the docket for this action (Docket ID No. EPA-HQ-OAR-2016-0243).

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, and does not significantly or uniquely affect small governments. While this action creates an enforceable duty on the private sector and one facility owned by a tribal government, the cost does not exceed \$100 million or more.

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. Thus, Executive Order 13175 does not apply to this action. However, consistent with the EPA policy on coordination and consultation with Indian tribes, the EPA will offer government-to-government consultation with tribes as requested.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action proposes emission standards for previously unregulated pollutants; therefore, the rule should result in health benefits to children by reducing the level of HAP emissions from the PCWP manufacturing process.

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. In this proposed action, the EPA is setting emission standards for previously unregulated pollutants. This does not impact energy supply, distribution, or use.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action involves technical standards. Therefore, the EPA conducted searches for the PCWP NESHAP through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). We also conducted a review of voluntary consensus standards (VCS) organizations and accessed and searched their databases. We conducted searches for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 2F, 2G, 3, 3A, 3B, 4, 5, 10, 18, 25A, 26A, 29 of 40 CFR part 60, appendix A; 204, 204A, 204B, 204C, 204D, 204E, 204F, 205 of 40 CFR part 51, appendix M; 308, 316, 320, 326 of 40 CFR part 63; OTM-46, and 0011 (SW-846). During the EPA’s VCS search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that are similar to the EPA’s referenced method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. We reviewed all potential standards to determine the practicality of the VCS for this rule. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering, and policy equivalence to procedures in the EPA referenced methods. The EPA may reconsider determinations of

impracticality when additional information is available for any particular VCS.

Detailed information on the VCS search and determination can be found in the memorandum, *Voluntary Consensus Standard Results for NEHSAP: Plywood and Composite Wood Products*, which is available in the docket for this action (Docket ID No. EPA-HQ-OAR-2016-0243). Two VCS were identified as acceptable alternatives to the EPA test methods for this proposed rule.

The VCS ANSI/ASME PTC 19.10–1981 Part 10 (2010), “Flue and Exhaust Gas Analyses,” is an acceptable alternative to EPA Method 3B manual portions only and not the instrumental portion. This method determines quantitatively the gaseous constituents of exhausts resulting from stationary combustion sources. The manual procedures (but not instrumental procedures) of ASME/ANSI PTC 19.10–1981 Part 10 may be used as an alternative to EPA Method 3B for measuring the oxygen or carbon dioxide content of the exhaust gas. The gases covered in ASME/ANSI PTC 19.10–1981 are oxygen, carbon dioxide, carbon monoxide, nitrogen, sulfur dioxide, sulfur trioxide, nitric oxide, nitrogen dioxide, hydrogen sulfide, and hydrocarbons. However, the use in this rule is only applicable to oxygen and carbon dioxide. This VCS may be obtained from American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, telephone (800) 843–2763, <https://www.asme.org>. The EPA is proposing to incorporate by reference the VCS ANSI/ASME PTC 19.10–1981 Part 10 (2010), “Flue and Exhaust Gas Analyses,” as an acceptable alternative to EPA Method 3B manual portions only and not the instrumental portion.

The VCS ASTM D6348–12e1, “Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy,” is an acceptable alternative to EPA Method 320 with certain conditions. The VCS ASTM D6348–12e1 employs an extractive sampling system to direct stationary source effluent to an FTIR spectrometer for the identification and quantification of gaseous compounds. Concentration results are provided. This test method is potentially applicable for the determination of compounds that (1) have sufficient vapor pressure to be transported to the FTIR spectrometer and (2) absorb a sufficient amount of infrared radiation to be detected. The VCS ASTM D6348–12e1 may be obtained from <https://www.astm.org> or from the ASTM Headquarters at 100

Barr Harbor Drive, P.O. Box C700, West Conshohocken, Pennsylvania, 19428–2959. The EPA is proposing to incorporate by reference the VCS ASTM D6348–12e1, “Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform (FTIR) Spectroscopy,” as an acceptable alternative to EPA Method 320 in place of ASTM D6348–03. ASTM D6348–03(2010) was determined to be equivalent to EPA Method 320 with caveats. ASTM D6348–12e1 is a revised version of ASTM D6348–03(2010) and includes a new section on accepting the results from the direct measurement of a certified spike gas cylinder but lacks the caveats placed on the ASTM D6348–03(2010) version. ASTM D6348–12e1 is an extractive FTIR field test method used to quantify gas phase concentrations of multiple analytes from stationary source effluent and is an acceptable alternative to EPA Method 320 at this time with caveats requiring inclusion of selected annexes to the standard as mandatory. When using ASTM D6348–12e1, the following conditions must be met:

- The test plan preparation and implementation in the Annexes to ASTM D6348–03, sections A1 through A8 are mandatory; and
- In ASTM D6348–03, Annex A5 (Analyte Spiking Technique), the percent (%) R must be determined for each target analyte (Equation A5.5).

In order for the test data to be acceptable for a compound, percent R must be 70 percent $\geq R \leq 130$ percent. If the percent R value does not meet this criterion for a target compound, the test data is not acceptable for that compound and the test must be repeated for that analyte (*i.e.*, the sampling and/or analytical procedure should be adjusted before a retest). The percent R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated percent R value for that compound by using the following equation:

$$\text{Reported Results} = ((\text{Measured Concentration in Stack})/(\text{percent R}) \times 100).$$

In addition to the VCS mentioned earlier in this preamble, we are proposing to incorporate by reference ASTM D1835–05, “Standard Specification for Liquefied Petroleum (LP) Gases,” for use in the proposed definition of natural gas in 40 CFR 63.2292, and ASTM D2879–18, “Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isotenoscope” for use in the

proposed definition of maximum true vapor pressure in 40 CFR 63.2292. The VCS ASTM D-1835-05 covers those products commonly referred to as liquefied petroleum gases, consisting of propane, propene (propylene), butane, and mixtures of these materials. With ASTM D2879-18, the vapor pressure of a substance as determined by isotenoscope reflects a property of the sample as received including most volatile components but excluding dissolved fixed gases such as air. The isotenoscope method is designed to minimize composition changes which may occur during the course of measurement. These VCS ASTM may be obtained from <https://www.astm.org> or from the ASTM Headquarters at 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, Pennsylvania, 19428-2959.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to

make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or Indigenous peoples) and low-income populations.

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations, and/or Indigenous peoples. The assessment of populations in close proximity of PCWP manufacturing facilities shows that the percentage of African Americans, Native Americans, people below poverty level, and people over 25 without a high school diploma are higher than the national average (see section V.F of the preamble). The higher percentages are driven by 19 of the 223 facilities in the source category.

The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on

people of color, low-income populations, and/or Indigenous peoples. The EPA is proposing MACT standards for total HAP, MDI, PM as a surrogate for non-Hg metals, Hg, HCl, PAH, and D/F. The EPA expects all 223 PCWP facilities to implement changes to comply with the MACT standards (e.g., control measures, work practices, emissions testing, monitoring, reporting, and recordkeeping for the process units used) and expects that HAP exposures for the people of color and low-income individuals living near these facilities would decrease.

The information supporting this Executive Order review is contained in section V.F of this preamble.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

[FR Doc. 2023-10067 Filed 5-17-23; 8:45 am]

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Part III

Department of Transportation

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, and 193

Pipeline Safety: Gas Pipeline Leak Detection and Repair; Proposed Rule

DEPARTMENT OF TRANSPORTATION**Pipeline and Hazardous Materials
Safety Administration****49 CFR Parts 191, 192, and 193**

[Docket No. PHMSA–2021–0039]

RIN 2137–AF51

**Pipeline Safety: Gas Pipeline Leak
Detection and Repair**

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: PHMSA proposes regulatory amendments that implement congressional mandates in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 to reduce methane emissions from new and existing gas transmission pipelines, distribution pipelines, regulated (Types A, B, C and offshore) gas gathering pipelines, underground natural gas storage facilities, and liquefied natural gas facilities. Among the proposed amendments for part 192-regulated gas pipelines are strengthened leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures. Finally, PHMSA proposes expanded reporting requirements for operators of all gas pipeline facilities within DOT's jurisdiction, including underground natural gas storage facilities and liquefied natural gas facilities.

DATES: Written comments on this NPRM must be submitted by July 17, 2023. The agency will, consistent with 49 CFR 190.323, consider late-filed comments to the extent practicable.

ADDRESSES: You may submit comments identified by the docket number PHMSA–2021–0039 by any of the following methods:

E-Gov Web: <https://www.regulations.gov>. This site allows the public to enter comments on any **Federal Register** notice issued by any agency. Follow the online instructions for submitting comments.

Mail: Docket Management System: U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building

Ground Floor, Room W12–140, Washington, DC 20590–0001.

Hand Delivery: U.S. DOT Docket Management System, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001 between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

Fax: 1–202–493–2251.

Instructions: Please include the docket number PHMSA–2021–0039 at the beginning of your comments. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA has received your comments, include a self-addressed stamped postcard. Internet users may submit comments at <https://www.regulations.gov/>.

Note: Comments are posted without changes or edits to <https://www.regulations.gov>, including any personal information provided. There is a privacy statement published on <https://www.regulations.gov>.

Privacy Act: In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to www.regulations.gov, as described in the system of records notice (DOT/ALL–14 FDMS), that can be reviewed at www.dot.gov/privacy.

Confidential Business Information: Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA, 5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this document contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this notice, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 CFR 190.343, you may ask PHMSA to give confidential treatment to information you give to the agency by taking the following steps: (1) mark each page of the original document submission containing CBI as “Confidential”; (2) send PHMSA, along with the original document, a second copy of the original document with the CBI deleted; and (3) explain why the information you are submitting is CBI. Submissions containing CBI should be sent to Sayler Palabrica, Office of Pipeline Safety (PHP–30), Pipeline and Hazardous Materials Safety Administration (PHMSA), 2nd Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, or by email at sayler.palabrica@dot.gov.

dot.gov. Any commentary PHMSA receives that is not specifically designated as CBI will be placed in the public docket.

Docket: For access to the docket to read background documents or comments received, go to <http://www.regulations.gov>. Follow the online instructions for accessing the docket. Alternatively, you may review the documents in person at the street address listed above.

FOR FURTHER INFORMATION CONTACT: Sayler Palabrica, Transportation Specialist, by telephone at 202–744–0825 or by email at sayler.palabrica@dot.gov.

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I. Executive Summary**A. Purpose of Regulatory Action**

This notice of proposed rulemaking (NPRM) proposes a series of regulatory

amendments to the Federal pipeline safety regulations (49 CFR parts 190 through 199) in response to a bipartisan congressional mandate in the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020, Pub. L. 116–260) and in support of the Biden-Harris Administration's U.S. Methane Emissions Reduction Action Plan. The amendments would reduce both “fugitive emissions” (meaning unintentional emissions resulting from leaks and equipment failures) and “vented emissions” (meaning those emissions resulting from blowdowns, equipment design features, and other intentional releases, also called “intentional emissions”) from over 2.7 million miles of gas transmission, distribution, and gathering pipelines and other gas pipeline facilities as well as 403 underground natural gas storage facilities (UNGSFs) and 165 liquefied natural gas (LNG) facilities, thereby improving public safety, promoting environmental justice, and addressing the climate crisis.

The Federal pipeline safety regulations currently covering leak detection and repair reflect a regulatory approach focused on public safety risks posed by incidents on gas pipeline facilities. The regulations do not sufficiently capture environmental costs, align with the importance attached to environmental protection in PHMSA's enabling statutes,¹ or reflect the scientific consensus that prompt reductions in methane emissions from natural gas infrastructure are critical to limiting the impacts of climate change. This current approach also foregoes opportunities to ensure timely identification and repair of leaks that can degrade into catastrophic failures and incidents threatening to public safety. The Federal leak detection and repair standards for gas pipelines have remained largely unchanged since the 1970s despite significant improvements in leak detection technology and operator practices and the increasingly urgent and tangible threats from climate change. The current pipeline safety regulations do not include *any* meaningful performance standards for leak detection equipment, nor requirements that leverage the significant advancements in the sensitivity, efficiency, and variety of leak detection technologies in the last five decades. Further, the current pipeline safety regulations do not explicitly require repair of all—or even most—leaks on gas pipeline facilities.

Leaks that an operator determines do not to present an existing or probable public safety hazard do not need to be repaired at all regardless of the resulting environmental harms posed by that release. Current regulations also do not prescribe specific timeframes for the timely repair of hazardous or any other leaks, other than leaks associated with certain metal loss, cracking, and denting defects that are discovered on gas transmission piping during an integrity assessment in accordance with gas transmission integrity management in subpart O of 49 CFR part 192 or § 192.714. Additionally, despite a new self-executing section of the PIPES Act of 2020, described below, current regulations tolerate significant intentional emissions of methane and other gases, even in non-emergency situations, by allowing venting, blowdowns, and other large-volume releases of gas from all PHMSA-jurisdictional pipeline facilities without restriction. Consistent with the pipeline safety regulations' historical lack of emphasis on the environmental consequences of gas releases, PHMSA's minimum incident reporting threshold was established principally to better reflect the economic consequence of lost gas² and was set at 3 million standard cubic feet (MMCF), which leaves many large-volume gas releases unreported. And PHMSA has no reporting requirements for intentional releases of gas at all.

Congress targeted these regulatory shortcomings in the bipartisan PIPES Act of 2020. Section 113 mandated that PHMSA establish performance standards for leak detection and repair programs for certain part 192-regulated³

² Prior to the adoption of the volumetric incident criterion, the cost of lost gas was included in the property damage calculation. In the NPRM that proposed the adoption of a volumetric threshold, PHMSA described both a petition from the Interstate Natural Gas Association of America noting that more incidents were reportable due to changes in the cost of gas, as well as a GAO recommendation (GAO–06–946) to adjust the incident reporting criteria to account for the cost of lost gas. That NPRM did not identify environmental considerations among the motivations for that change in incident reporting requirements. See 74 FR 31675, 31677 (July 2, 2009).

³ Throughout this NPRM, PHMSA uses the phrase “part 192-regulated gas gathering pipelines” to refer to offshore gas gathering pipelines, as well as Types A, B, and C “regulated onshore gas gathering” pipelines—all of which are subject to certain part 192 requirements under §§ 192.8 and 192.9. Such “part 192-regulated gas gathering pipelines” does not include “reporting-regulated” or “Type R” gas gathering pipelines as defined in §§ 191.3 and 192.8(c)(3), which are not subject to part 192 safety requirements. Similarly, PHMSA also refers to “part 192-regulated gas pipelines” to collectively refer to gas transmission, distribution, offshore gathering, and Types A, B, and C onshore gathering pipelines subject to part 192 requirements. “Gas pipeline

gas gathering, transmission, and distribution operators reflecting commercially available advanced technology and practices for the identification, location, categorization, and repair of all leaks that are hazardous to public safety or the environment. Section 114 of the PIPES Act of 2020, moreover, requires operators of *all* pipeline facilities with maintenance and inspection procedures to update pertinent manuals to address the elimination of hazardous leaks and minimize releases of natural gas—whether fugitive emissions from leaks or intentional releases due to venting from maintenance and other activities—and repair or remediate pipelines known to leak. And section 118 of the PIPES Act of 2020 clarified that PHMSA must consider environmental benefits equally with public safety benefits. The mandates in the PIPES Act of 2020 align with the importance of addressing climate change by reducing methane emissions.

PHMSA proposes a number of regulatory revisions to minimize emissions of methane and other (flammable, toxic, or corrosive) gases from, and improve public safety of, new and existing offshore gas gathering, regulated onshore gas gathering, transmission and distribution pipelines, UNGSFs and LNG facilities. PHMSA expects that the proposed regulatory amendments would yield prompt and meaningful reduction of methane emissions, a key contributor to climate change; improve public safety; and mitigate the disproportionate burden of those environmental and safety risks historically placed on minority, low-income, or other underserved and disadvantaged populations and communities.

B. Summary of the Regulatory Provisions

This NPRM contains the following proposed changes to the regulations: (1) strengthen leakage survey and patrolling requirements at §§ 192.9, 192.705, 192.706, 192.723 for all part 192-regulated gas pipelines, as well as introduce periodic methane leakage survey requirements for part 193-regulated LNG facilities; (2) introduce for all part 192-regulated gas pipelines an Advanced Leak Detection Program (ALDP) performance standard at a new § 192.763 reflecting the capabilities of

facilities” is defined as “a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation”—this broader definition applies to all part 192-regulated gas pipelines, UNGSFs, and part 193-regulated LNG facilities. See 49 U.S.C. 60101(a)(3).

¹ 49 U.S.C. 60102(b)(1)(B)(ii), 60102(b)(2)(A)(iii), 60102(b)(5), 60102(q)(1)(B), 60102(q)(2)(B)(i).

commercially available advanced technologies and practices; (3) amend § 192.703 to require operators of all part 192-regulated gas pipelines to grade and repair all leaks, and not merely those that pose public safety risks; (4) establish for all part 192-regulated gas pipelines minimum criteria for leak grades and associated repair schedules prioritized by safety and environmental hazard at a new § 192.760; (5) require reductions in intentional sources of methane emissions by minimizing releases associated with blowdowns and other vented emissions from gas transmission, offshore gas gathering, and Type A gas gathering pipelines (at § 192.770) and LNG facilities (at § 193.2523); (6) require operators of certain part 192-regulated gas pipelines to reduce emissions associated with the design, configuration, and maintenance of pressure relief devices (§§ 192.199 and 192.773); (7) codify in Federal regulations a congressional requirement for operators of gas pipeline facilities to implement written procedures to eliminate hazardous leaks, minimize releases of natural gas, and remediate or replace pipelines known to leak (§§ 192.9, 192.12, 192.605, 193.2503, and 193.2605); (8) expand reporting requirements (at §§ 191.3 and 191.19) and recordkeeping requirements (at §§ 192.760 and 192.773) to provide higher-quality information on unintentional and intentional gas releases from gas pipeline facilities; (9) require that Types A, B, and C gathering pipeline operators submit geospatial pipeline location data to the National Pipeline Mapping System (NPMS) pursuant to § 191.29; (10) incorporate explicit reference to *environmental* harm among the “hazards” addressed in certain parts 191 and 192 requirements; and (11) introduce, for certain components and equipment within part 193-regulated LNG facilities, at a new § 193.2624, requirements for periodic methane leakage surveys using leak detection equipment and repair of identified leaks pursuant to operators’ written maintenance or abnormal operations procedures. PHMSA proposes an effective date for this rulemaking of 6 months following publication of a final rule in the **Federal Register**. The eleven proposed requirements are described in the paragraphs immediately below, and further detail is provided in sections IV and V.

First, PHMSA proposes increased leakage survey frequencies for distribution pipelines outside of

business districts,⁴ annual leakage surveys for distribution pipelines that lack cathodic protection or which are known to leak based on their material (cast-iron, cathodically unprotected steel, wrought-iron, and certain plastic pipelines), design, or operational and maintenance history; and for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines in high consequence areas (HCAs), with the most frequent leakage surveys to be performed on gas transmission and Types A and B gathering pipelines located in HCAs within Class 4 locations. PHMSA also proposes to increase minimum patrolling frequencies for gas transmission, offshore gathering, and Type A gathering pipelines and to introduce requirements for annual patrolling of Type B and Type C gathering pipelines. Finally, PHMSA proposes to establish methane leakage survey requirements for LNG facilities other than tanks.

Second, PHMSA proposes to introduce an ALDP performance standard that would require operators of part 192-regulated gas pipelines to demonstrate, by conducting engineering tests and analyses, that their suite of leak detection equipment, procedures, and analytics are capable of detecting all leaks above a minimum concentration threshold when measured in close proximity to the pipeline. PHMSA proposes to require that leakage surveys be performed using commercially available advanced technology and practices consistent with the proposed ALDP performance standard. PHMSA also proposes to require a minimum sensitivity for leak detection equipment used in leakage surveys and leak investigations. PHMSA proposes to limit the use of human or animal senses for leakage surveys to offshore, submerged gas transmission and gathering pipelines. Human senses may also be used for gas transmission and regulated gas gathering lines in Class 1 and Class 2 locations outside of HCAs, but only with prior notification to and no objection from PHMSA in accordance with § 192.18.

Third, PHMSA proposes to require operators of gas transmission, distribution, and part 192-regulated gathering pipelines to identify, locate, classify, and repair in a timely manner

all leaks. Part 192 provisions governing the repair of leaks are narrowly focused on public safety risks associated with ignition of large-volume, instantaneous releases and accumulated gas; they are unclear regarding when, if at all, most leaks must be repaired. Although some—not all—part 192-regulated pipelines are subject to a general maintenance requirement in § 192.703(c) to “promptly repair hazardous leaks,” part 192 maintenance requirements neither define “hazardous leak” in terms of risks to the environment nor establish meaningful timelines for repair of hazardous or any other leaks. These proposed amendments would address the section 113 mandate of the PIPES Act of 2020 requiring identification, location, classification, and repair of leaks hazardous to either public safety or the environment.

Fourth, this NPRM proposes that operators of gas transmission, distribution, and part 192-regulated gathering pipelines must classify and repair all identified leaks on a schedule that depends on the severity of public safety and environmental risks. PHMSA’s proposed requirements build on the tiered framework of the Gas Piping Technology Committee (GPTC) “Guide for Gas Transmission and Distribution Piping Systems”⁵ leak grading and repair criteria. PHMSA’s proposed framework would require the classification of every leak (as either grade 1, grade 2, or grade 3) and to prioritize remediation of leaks posing the most significant risks to public safety or the environment.

Fifth, PHMSA proposes requirements for the mitigation of intentional emissions such as blowdowns on gas transmission, offshore gas gathering, and Type A gas gathering pipelines and LNG facilities. This proposal requires an operator to choose from among prescribed, proven, cost-effective mitigation measures when performing blowdowns related to operations, maintenance, or construction.

Sixth, PHMSA proposes requirements for operators of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to design and configure all new and modified pressure relief and limiting devices to minimize unnecessary releases and to assess and remediate any relief devices that operate outside of the tolerances established in the operator’s procedures. These proposed

⁴ The term “business district” is not defined in part 192. However, in a letter of interpretation PHMSA stated that the term normally refers to an area “associated with the assembly of people in shops, offices and the like,” marked by the conduct of “buying and selling commodities and services, and related transactions.” See PHMSA, Interpretation Response Letter No. PI-72-038 (Aug. 16, 1972).

⁵ Gas Piping Technology Committee Z380, ANSI GPTC Z380.1-2022, “The Guide for Gas Transmission, Distribution, and Gathering Piping Systems” Including Addenda 1 and 2 (2022).

requirements would minimize unintended and unnecessary releases of gas to the atmosphere, better protecting against environmental and public safety hazards posed by malfunctioning or poorly designed and configured pressure relief devices.

Seventh, PHMSA proposes to codify in regulation self-executing requirements from section 114 of the PIPES Act of 2020, which obliges operators of gas pipeline facilities to have written procedures that address the elimination of hazardous leaks, minimize releases of natural gas, and provide for repair or replacement of pipelines known to leak based on material, design, or past operating and maintenance histories. These changes would support PHMSA's cooperation with states undertaking inspection and enforcement activity in connection with those requirements.

Eighth, this NPRM proposes a series of changes to part 191 reporting requirements. PHMSA proposes to introduce requirements for reporting large-volume releases of gas from all gas pipeline facilities, including intentional releases, that are not currently captured by the definition of an incident in part 191. Specifically, this NPRM proposes to create a report for both unintentional releases and, for the first time, intentional releases of 1 MMCF or more of gas from any gas pipeline facility. PHMSA also proposes revisions to annual reporting requirements for gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to convey information regarding the number and grade of all leaks detected and repaired each calendar year as well as estimated emissions from those leaks.

Ninth, this NPRM further proposes to extend NPMS reporting requirements at § 191.29 to offshore gas gathering pipelines as well as Types A, B, and C onshore gas gathering pipelines.

Tenth, this NPRM proposes incorporation of explicit reference to *environmental* harm among the "hazards" addressed in certain part 191 and 192 requirements, consistent with section 118 of the PIPES Act of 2020. PHMSA's proposed expansion of the concept of "hazards" to encompass environmental harms would not extend to integrity management (IM) regulations in part 192, subparts O (gas distribution pipelines) and P (gas transmission pipelines), which would remain focused on safety, and certain other existing requirements directed at hazards to public safety in particular (described in detail in section IV.J).

Finally, this NPRM proposes a new § 193.2624 that would oblige operators

of part 193-regulated LNG facilities to perform quarterly methane leakage surveys of non-tank equipment and components within an LNG facility using leak detection equipment satisfying the minimum 5 parts per million (ppm) sensitivity proposed elsewhere within this NPRM. Operators would also need to repair any leaks identified in a manner and on a schedule consistent with their maintenance or abnormal operations procedures. PHMSA also proposes conforming changes to annual report forms for LNG facilities to ensure meaningful reporting of methane leaks discovered and repaired pursuant to the proposed § 193.2624.

C. Costs and Benefits

Consistent with Executive Order (E.O.) 12866 and the requirements of the Federal Pipeline Safety Laws,⁶ PHMSA has prepared an assessment of the benefits and costs (to include pertinent commercial benefits, public safety benefits, environmental benefits, equity benefits, compliance costs, and other risks) of this proposed rule, as well as reasonable alternatives. PHMSA estimates that emission reductions under the proposed rule correspond to approximately 72 percent of unintentional emissions from regulated gathering pipelines, 17 percent of unintentional emissions from transmission pipelines, and 44 to 62 percent of unintentional emissions from distribution pipelines. These shares are relative to modeled baseline emissions projected over the period of analysis based on the pipeline mileage, empirical emission factors, and existing survey and repair practices. Further, PHMSA estimates that the total avoided blowdown emissions under the proposed rule correspond to approximately 43 percent of baseline blowdown emissions. PHMSA estimates that the proposed rule would result in monetized net benefits between \$341 to \$1,440 million per year using a 3 percent discount rate. PHMSA also anticipates additional unquantified benefits to public safety and the environment, each discussed throughout this NPRM and its supporting documents (including the Preliminary Regulatory Impact Analysis (RIA) and draft Environmental Assessment (EA), each available in the docket for this NPRM).

The regulatory amendments proposed in this NPRM are expected to improve public safety, reduce threats to the

environment (including, but not limited to, reduction of methane emissions contributing to the climate crisis), and promote environmental justice for minority populations, low-income populations, and other underserved and disadvantaged communities. Additionally, reducing product losses results in cost savings for natural gas shippers and consumers and improves the efficiency and reliability of U.S. energy infrastructure. PHMSA expects that each of the elements of this rulemaking as proposed in this NPRM would be technically feasible, reasonable, cost-effective, and practicable because of the public safety, environmental, and equity benefits of the proposed regulatory amendments described in this NPRM and its supporting documents (including the Preliminary RIA and draft EA) which justify any associated costs. PHMSA has preliminarily determined that the proposed rule is superior to alternatives considered in the Preliminary RIA.

II. Background

A. The Urgency of Methane Emissions Reductions in Confronting the Climate Crisis

The primary component of natural gas is methane (CH₄). Methane is a greenhouse gas, or GHG, which means that its concentration in the atmosphere affects the climate and temperature of the Earth by trapping heat in the atmosphere. Methane is released from both natural and anthropogenic sources, the latter of which includes leaks and other releases from natural gas pipeline systems. Methane is the second most abundant anthropogenic GHG in the Earth's atmosphere, after carbon dioxide (CO₂), by concentration and accounts for the second-greatest contribution to total radiative forcing (warming effect).⁷ The Environmental Protection Agency (EPA) calculated that methane made up approximately 11 percent (by mass of CO₂ equivalents) of the annual GHG emissions in 2019 within the United States, whereas carbon dioxide made up 79 percent of the total GHG emissions over the same period.⁸ According to the 2021 installment of the Sixth Assessment Report (2021 IPCC Report) from Working Group I of the Intergovernmental Panel on Climate Change (IPCC), the atmospheric concentration of methane gas was

⁷ National Oceanic and Atmospheric Administration (NOAA), "Annual Greenhouse Gas Index" at Figure 3 & Table 2 (Spring 2022), <https://gml.noaa.gov/aggi/aggi.html>.

⁸ EPA, "Overview of Greenhouse Gases," <https://www.epa.gov/ghgemissions/overview-greenhouse-gases#methane> (last accessed December 5, 2022).

⁶ 49 U.S.C. 60101 *et seq.* (Federal Pipeline Safety Laws). The specific provision referenced in the above discussion is 49 U.S.C. 60102(b)(5).

measured at 1,866 parts per billion (ppb), compared with 410 ppm of carbon dioxide.⁹

However, this comparatively small concentration of methane in the atmosphere makes an outsized contribution to climate change. The 2021 IPCC Report notes that anthropogenic methane emissions account for approximately one-third of warming of global average surface temperatures attributed to well-mixed GHG¹⁰ emissions since 1850.¹¹ The IPCC also noted that in 2019, atmospheric CH₄ concentrations were higher than at any time in 800,000 years, and that “strong, rapid and sustained reductions in CH₄ emissions” would be needed to offset short-term warming effects.¹²

Once emitted into the atmosphere, some GHGs can persist in the atmosphere for a long time. Carbon dioxide, for instance, remains in the atmosphere for 300 to 1000 years.¹³ Methane, on the other hand, is more short-lived than CO₂ but is much more potent in trapping heat in the atmosphere. Methane only lasts in the atmosphere for approximately 12 years once released; however, it traps approximately 25 times more energy than an equal mass of carbon dioxide over a 100-year period.¹⁴ Because methane is a more potent, but more short-lived, GHG compared to carbon dioxide, reducing methane emissions would have a more rapid and significant effect on reducing heat-trapping potential of the atmosphere than an equivalent reduction in carbon dioxide and would therefore result in a greater

effect on climate change mitigation in the short term.¹⁵

Authoritative scientific projections underscore the need for achieving a prompt reduction in methane emissions. The 2021 IPCC Report concluded that urgent action to reduce emissions across all GHG categories is necessary to minimize global warming and avoid the most destructive effects of climate change.¹⁶ The report details five possible future emissions and warming scenarios: two high emissions scenarios (SSP3–7.0 and SSP5–8.5), an intermediate scenario with emissions similar to the status quo through mid-century (SSP2–4.5), and two relatively low-emissions scenarios (SSP1–1.9 and SSP1–2.6). Of these, only the two low-emissions scenarios are likely to hold temperature increases below the Paris Agreement’s target of limiting the increase in global average surface temperature to 2.0 °C above 1850 levels by the end of the century,¹⁷ and only the very low-emissions scenario (SSP1–1.9) is likely to limit warming to 1.5 °C by the end of the century (specifically, between 1.0 ° to 1.8 °C above 1850 levels, consistent with the Paris Agreement). Both of those low-emissions scenarios require cutting methane emissions by approximately half of 2015 levels before 2050.¹⁸ Rapid and full-scale efforts to reduce methane and other GHG emissions are needed to achieve the very low-emissions scenario (SSP1–1.9).¹⁹ In contrast, the intermediate scenario (SSP2–4.5) results in potentially dangerous warming of 2.0 °C by midcentury, rising to between 2.1 ° to 3.5 °C by 2100.

B. Dimensions of the Climate Crisis

Near-term methane emissions reductions are especially compelling because global climate change is already causing observable, damaging effects on the environment. The 2021 IPCC Report shows that the environmental and social

consequences of climate change are no longer abstract, distant problems: scientists note increased surface temperature, extreme weather events, rising sea levels, and other consequences are being felt today and predict those effects will intensify in the coming decades without immediate action to control GHG emissions to avoid or stave off the worst effects of climate change. Higher average surface temperatures will result in sea level rise, severe heat waves, and more intense extreme weather events (hurricanes, storms, droughts, and floods), in turn altering water supplies, damaging habitats, and promoting wildfires. According to the findings from the 3rd and 4th National Climate Assessment Reports released by the U.S. Global Change Research Program,²⁰ these dimensions of climate change will have severe consequences for the human population throughout the United States including alteration of population distributions; widespread property damage; compromised local economies; disrupted agriculture, fisheries, and other ecosystems; and degraded public health.

The most immediate impact of climate change worldwide has been, and will continue to be, an increase in average surface temperatures. The average global surface temperature during 2021 was 1.51 degrees Fahrenheit (0.84 degrees Celsius) warmer than the average temperature in the 20th century (57.0 degrees Fahrenheit) and was 1.87 degrees Fahrenheit (1.04 degrees Celsius) warmer than the average temperature between 1880–1900, which NOAA describes as a “reasonable surrogate for pre-industrial conditions.”²¹ That observed surface temperature increase has resulted in cascading consequences for the natural world already; as more GHGs are added to the atmosphere, the rate of warming is expected to continue to accelerate.

Increasing the average surface temperature of the Earth changes the frequency and intensity of extreme temperature events. Higher average surface temperatures means that heat waves everywhere will become more frequent and more intense.²² The IPCC estimates that current levels of warming

⁹ IPCC, *Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Summary for Policymakers* (SPM–5 (2021)). In the 2021 IPCC Report, atmospheric concentration of CH₄ since 1984 (1980 for CO₂) is based on merging observed gas concentration in the lower troposphere from the NOAA Global Monitoring Laboratory and the Advanced Global Atmospheric Gases Experiment monitoring networks. Emissions in 1850 and earlier are estimated based on assessments of multiple ice cores. 2021 IPCC Report, Table 2.2 and Table AIII.1a.

¹⁰ According to the IPCC, well-mixed GHGs include CO₂, N₂O, and CH₄. 2021 IPCC Report, 2.2. These gases “generally have lifetimes of more than several years” and therefore are relatively uniformly distributed within the troposphere (lower-atmosphere). 2021 IPCC Report, 2.2.3.

¹¹ 2021 IPCC Report, SPM–8.

¹² 2021 IPCC Report, SPM–9, SPM–36.

¹³ Buis, “The Atmosphere: Getting a Handle on Carbon Dioxide” (Oct. 9, 2019).

¹⁴ EPA, “Overview of Greenhouse Gases,” <https://www.epa.gov/ghgemissions/overview-greenhouse-gases> (last accessed July 20, 2022).

¹⁵ EPA, “Importance of Methane,” <https://www.epa.gov/gmi/importance-methane> (last accessed July 20, 2022).

¹⁶ PHMSA acknowledges much of the discussion in section II and elsewhere in this NPRM is focused on methane emissions from natural gas pipeline facilities, as those facilities constitute the great majority of gas pipeline facilities subject to parts 191 and 192. However, PHMSA parts 191 and 192 requirements are not limited to natural gas pipelines; rather, they also apply to pipeline facilities transporting other gases which are flammable, toxic, or corrosive—releases of which may entail significant public safety or environmental consequences (including potential contributions to climate change) in their own right. See §§ 191.3 and 192.3 (definitions of “gas” for the purposes of parts 191 and 192, respectively).

¹⁷ 2021 IPCC Report, 1.2.

¹⁸ 2021 IPCC Report, SPM–16, Table SPM.1.

¹⁹ 2021 IPCC Report, Table SPM.1.

²⁰ See U.S. Global Change Research Program, *Climate Science Special Report: Fourth National Climate Assessment, Volume I* (2017); U.S. Global Change Research Program, *Climate Change Impacts in the United States: The Third National Climate Assessment* (2014).

²¹ See NOAA National Centers for Environmental Information, *Monthly Global Climate Report for Annual 2021* (Jan. 2022), <https://www.ncei.noaa.gov/news/global-climate-202112>.

²² 2021 IPCC Report, SPM–8, SPM–18.

have made 10-year extreme heat events²³ approximately 1.2 degrees Fahrenheit more intense and 2.8 times more frequent. Likewise, the IPCC estimates that 50-year extreme heat events have become 4.8 times more frequent. The estimated frequency and intensity of extreme heat events will increase further with additional warming, especially in warmer summer months.²⁴

A well-known consequence of elevated (average and instantaneous) surface temperatures is rising sea levels. The global sea level has risen by about 5.9–9.8 inches (0.15–0.25 meters) between 1901 and 2018 and the rate of increase and degree to which sea level rise can be attributed with confidence to anthropogenic climate change have both increased since 1971.²⁵ The IPCC has determined that it is “virtually certain” that the global sea level will rise further by 2100, as land ice continues to melt and seawater expands as it warms, with greater sea level rise resulting from higher GHG emissions scenarios.²⁶ An expected contributor to global sea level rise is the loss of virtually all summer ice from the Arctic Ocean before 2050.²⁷ Global average sea levels are projected to rise an additional 1.0–4.3 feet by 2100 under intermediate emissions scenarios, with a global sea level rise in excess of 8 feet possible by 2100 under higher emissions scenarios.²⁸

Rising average surface temperatures also alter water cycles and weather patterns such as precipitation and hurricanes. As noted above, higher average and instantaneous surface temperatures will result in loss of soil moisture in most regions. Meanwhile, some areas are increasingly likely to experience heavy downpours, while other areas will likely receive far less precipitation than in years past.²⁹ Areas that are projected to have less total precipitation and higher temperatures will likely become more susceptible to drought and wildfires as a result; as described below, the United States has already seen the acreage affected by

wildfires trend upwards in recent decades. Scientists also project that the recent trend toward more frequent heavy precipitation events will continue, even in areas where the total precipitation is expected to decrease, which could lead to increased flooding risks, erosion, and land subsidence. As further noted below, earth and water movement are also threats to pipeline integrity that can lead to pipeline incidents and accidents that threaten public safety and the environment.³⁰ Similarly, scientists have observed that it is likely that hurricanes have become stronger and more intense and determined that it is likely that anthropogenic climate change has increased rainfall rates associated with hurricanes and other tropical cyclones.³¹

The United States has a front-row seat to the effects of climate change. Already, many areas of the United States are seeing increases in the duration and frequency of heat waves and altered precipitation patterns. The 2021 IPCC Report describes observed increases in extreme heat and drought events occurring around the world, including western North America.³² The Colorado River in the Southwest United States is facing its first-ever water shortage, a phenomenon that is directly linked to warming temperatures. Due to this historic shortage, in 2022, the U.S. Department of the Interior’s Bureau of Reclamation proposed significant cuts to water allocations from the Colorado River to Arizona, Nevada, and Mexico in order to ensure continued operation of hydroelectric generation facilities.³³ In late June and early July of 2021, the Western part of the United States and Canada suffered a heat wave that was likely exacerbated by climate change, with consequences ranging as far north as the Yukon territory in Canada, and as far inland as the State of Montana. Much of the Pacific Northwest reached temperatures that were 20 to 35 degrees Fahrenheit above normal during this heat wave, with several daily high temperature records being broken. Temperatures grew so hot that nighttime low temperatures in many areas were higher than historical average daytime high temperatures.

Higher average surface temperatures and extreme instantaneous temperatures have also exacerbated wildfires in the United States. Prolonged heat has led to dry vegetation, and the heat and dry vegetation have contributed to the severity of several wildfires. According to the research compiled in the 4th National Climate Assessment, drought in California and the Colorado River Basin have made forests “more susceptible to burning” and caused “spring-like temperatures to occur earlier in the year,” extending the western fire season³⁴ and doubling the cumulative forest area burned by wildfires between 1984 and 2015.³⁵ Wildfires pose serious health risks, including illnesses from smoke inhalation and contaminated drinking water, and cause significant property damage (\$3.1 billion in the Los Angeles area alone from 1990 to 2009, or approximately \$4 billion in 2021 dollars).³⁶ The 4th National Climate Assessment cautions that the frequency and intensity of wildfires in the Western United States will increase with further warming, with higher emissions scenarios estimating a 25% increase in wildfires in the Southwest region and three times as many wildfires that exceed 5,000 hectares in size.³⁷ Researchers at the University of California, Los Angeles and Columbia University have determined that the 22-year period from 2000–2021 was the driest such period in the Southwestern United States since the year 800, due in large part to climate change.³⁸ Climate change poses a significant threat of extending the drought even further. In fact, the Southwestern drought is expected to persist through at least the end of 2022 and become the longest megadrought on record in the Southwestern United States, further endangering sources of water, and the

²³ Defined by the IPCC as “daily maximum temperatures over land that were exceeded on average once in a decade (10-year event) or once every 50 years (50-year event) during the 1850–1900 reference period.” See 2021 IPCC Report, SPM–24.

²⁴ 2021 IPCC Report, SPM–23.

²⁵ 2021 IPCC Report, SPM–6.

²⁶ 2021 IPCC Report, SPM–28.

²⁷ European Space Agency (ESA), “Simulations Suggest Ice-Free Arctic Summers by 2050” (May 13, 2020), <https://climate.esa.int/en/projects/sea-ice/news-and-events/news/simulations-suggest-ice-free-arctic-summers-2050/>.

²⁸ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southeast* at 758. (2018).

²⁹ 2021 IPCC Report, SPM–15.

³⁰ PHMSA, “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,” 87 FR 33576 (June 2, 2019) (Advisory Bulletin ADB–2022–01).

³¹ 2021 IPCC Report, SPM–9.

³² 2021 IPCC Report, SPM–12.

³³ Yanchin, “Interior Threatens Colorado River Cuts,” *E&E News* (Oct. 28, 2022), <https://www.eenews.net/articles/interior-threatens-colorado-river-cuts/>.

³⁴ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1115, 1116 (2018).

³⁵ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1115, 1135 & Figure 25.4 (2018).

³⁶ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1116 (2018); Inflation adjustment via Consumer Price Index inflation from December 2009 to December 2021.

³⁷ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southwest* at 1116 (2018).

³⁸ Williams et al., “Rapid Intensification of the Emerging Southwestern North American Megadrought in 2020–2021,” 12 *Nature Climate Change* (Mar. 1, 2022).

communities that rely on them, throughout the region.³⁹

The United States will also experience dramatically altered precipitation and weather patterns from climate change. Increases in GHG concentrations in the atmosphere have already led to increased Atlantic hurricane activity, and a warming climate is projected to cause extreme rainfall and significant regional flooding from hurricanes, nor'easters, and other severe storms, in addition to exacerbating the intensity of hurricanes in the Atlantic and eastern North Pacific.⁴⁰ While projections are difficult to make for infrequent, smaller weather events like tornadoes and severe thunderstorms, these events have also been recently exhibiting changes that may be caused by climate change.⁴¹ Moreover, tornadoes can be generated by hurricanes (such as the 25 tornadoes produced by Hurricane Irma in 2017, mostly along the east coast of Florida), and more intense hurricanes could generate more tornadoes.

Climate change-induced sea level rise is and will continue to be experienced in the United States. Sea level rise has already led to more frequent high tide flooding. One study of flooding in 27 communities cited in the Fourth National Climate Assessment found that the frequency of high tide flooding in several communities has increased by a factor of 5 or more, and that such flooding increased by a factor of 10 or more in Atlantic City (NJ), Baltimore (MD), Annapolis (MD), Wilmington (DE), Port Isabel (TX), and Honolulu (HI).⁴² In the Southeast, tidal data from the National Oceanic and Atmospheric Administration shows sea level rise of 1–3 feet has already occurred over the past 100 years. The effects of sea level rise are not distributed equally across the world, nor along the U.S. coastline; instead, the Northeast United States, eastern coast of Florida, and western Gulf Coast regions will likely experience the worst impacts from rising sea levels

and coastal flooding due to ocean circulation, land subsidence, and uneven ice melt. The 4th National Climate Assessment identifies an average of 2 to 4.5 feet as the most probable sea level rise in the Northeast United States before 2100 with worst-case estimates projecting sea level rise of more than 11 feet over the same period.⁴³ Under higher emission projections, the 4th National Climate Assessment found it likely that all U.S. coastlines, other than Alaska, will experience sea level rise greater than the global averages due to Antarctic ice loss. By 2100, sea level rise is likely to submerge real estate worth between \$238–507 billion across the United States and force the migration of substantial elements of the U.S. population.⁴⁴ Average sea level rise of 6 feet by 2100 could displace an estimated 13.1 million people along the U.S. coasts.⁴⁵

These and other dimensions of the climate crisis also have disastrous near and long-term consequences for human health. The EPA Administrator, as early as 2009⁴⁶ (and again in 2016),⁴⁷ determined that methane along with 5 other “well-mixed greenhouse gases” together constituted a harmful air pollutant that endangered public health and welfare of persons. According to the 2016 assessment of human health impacts of climate change from the U.S. Global Change Research Program (2016 Assessment), climate change will likely contribute to “thousands to tens of thousands of premature heat-related deaths in the summer” in the United States in the years ahead.⁴⁸ Indeed, the heat wave in summer 2021 discussed above resulted in excess heat-related deaths of 143 in Washington, 119 in Oregon, 13 in California, and 619 in British Columbia according to public health authorities.⁴⁹ The 2016

Assessment also notes climate change is likely to result in “meteorological conditions increasingly conducive to forming ozone over most of the United States,” which is likely to result in “premature deaths, hospital visits, lost school days, and acute respiratory symptoms.”⁵⁰ The 4th National Climate Assessment also notes that, in addition to the immediate hazard to life and property, climate change-induced wildfires will result in direct hazards to human health in the form of burns, smoke inhalation, exacerbation of particulate and ozone pollution, and negative impacts on water quality.⁵¹

Increased intensity and frequency of extreme weather events (such as hurricanes and floods) from climate change also threaten human life and property. In the Northeast, high-tide flooding will impact low-lying areas with increased frequencies and could result in an additional \$6–9 billion in damages per year by 2100 in high emissions scenarios.⁵² In 2017, Hurricane Irma caused, in the United States, the deaths of 84 people and costs of approximately \$50 billion (with Florida suffering most of these costs). In the Midwest, the Fourth National Climate Assessment found precipitation has increased by between 5% to 15% since the 1901–1960 period; the Fourth National Climate Assessment projects that seasonal precipitation during winter and spring associated with flood risk could increase by “by up to 33% by the end of the century.”⁵³ Extreme precipitation events and river flooding could damage private property and transportation infrastructure and overwhelm stormwater treatment facilities, resulting in water quality impacts, especially in communities with combined sewer overflows. In the Southern Great Plains States, increased frequency and severity of severe floods was also projected for the southern

During 2021 Heat Dome” (June 7, 2022). <https://news.gov.bc.ca/26965>.

⁵⁰ Methane also directly contributes to adverse air quality because it is a chemical precursor to ozone.

⁵¹ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Water* at 154 (2018); U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Air Quality* at 514, 519 (2018); U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume I—Southeast* at 755 (2018).

⁵² U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Northeast* at 695 (2018).

⁵³ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Midwest* at 914–16 (2018).

³⁹ Williams et al., “Rapid Intensification of the Emerging Southwestern North American Megadrought in 2020–2021,” 12 *Nature Climate Change* (Mar. 1, 2022).

⁴⁰ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Our Changing Climate* at 74, 95 (2018) (noting the heaviest rainfall amounts from recent storms have been estimated to be 6–7% greater than the most intense storms of the early 1900s).

⁴¹ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Our Changing Climate* at 97 (2018).

⁴² Sweet & Park, “From the Extreme to the Mean: Acceleration and Tipping Points of Coastal Inundation from Sea Level Rise,” *Earth’s Future* 2 at 579–600 (2014).

⁴³ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Northeast* at 692 (2018).

⁴⁴ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Coastal Effects* at 330, 335 (2018).

⁴⁵ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Coastal Effects* at 335 (2018).

⁴⁶ 74 FR 66495 (Dec. 15, 2009).

⁴⁷ 81 FR 54422 (Aug. 15, 2016).

⁴⁸ U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment—Executive Summary* at 6 (2016).

⁴⁹ U.S. Department of Health and Human Services, Office of Climate Change and Health Equity, *Climate and Health Outlook: Extreme Heat* (June 2022), <https://www.hhs.gov/sites/default/files/climate-health-outlook-june-2022.pdf>; British Columbia, “Minister’s Statement on 619 Lives Lost

Great Plains states, potentially resulting in significant costs from flood damage and adaptation costs.⁵⁴ The Fourth National Climate Assessment also found climate change-induced degradation of natural habitats, agricultural resources, water resources, and other ecological resources threaten the viability of subsistence and commercial activities that Federally recognized Indian Tribes depend on, such as “agriculture, hunting and gathering, fisheries, forestry, energy, recreation, and tourism,” and threaten Tribal water allocations in the Western United States.⁵⁵

Increased severe weather phenomena caused by climate change further threaten human health by wreaking havoc on public services and infrastructure. Hurricane Nicholas in the Gulf of Mexico in September 2021 caused widespread flooding and weeks of blackouts on the U.S. Gulf Coast, much as the increasingly long wildfire season in California is now routinely accompanied by threats of rolling blackouts. The summer 2021 heat wave that blanketed the Western United States damaged transportation infrastructure, closing multiple lanes on Interstate 5 and causing trains to operate at reduced speeds as a precaution against the potential deformation of rail tracks. Earlier, the 2017 Atlantic hurricane season produced the second and third costliest hurricanes in U.S. history, hurricane Harvey and Hurricane Maria. Hurricane Harvey caused more than 60 inches of rainfall over the Texas Gulf Coast, including the Houston metro area, and resulted in at least 68 direct casualties and approximately \$125 billion in storm-related damage.⁵⁶ Hurricane Maria caused widespread devastation in Puerto Rico, resulting in approximately \$90 billion dollars in damage and the near total loss of electric, water, and telecommunication infrastructure across the island, and electrical outages persisted for months across much of the island.⁵⁷

Pipeline infrastructure is similarly vulnerable to the impacts of climate change. For example, well-documented threats to pipeline infrastructure from natural force damage (which includes incidents caused by acts of nature such as flooding, land movement, and lightning) are likely to be exacerbated by climate change. On April 11, 2019, PHMSA published an advisory bulletin on the threat that severe flooding can have on pipeline integrity, especially at water crossings.⁵⁸ As described in further detail in the advisory bulletin, flooding and related earth movements can cause damage to pipelines in and around water crossings from direct water force, impacts from debris, added strain on pipeline structures through changes in loading conditions, and other means. Flooding can also threaten pipeline integrity by causing damage to aboveground, safety-critical components such as valves, pressure regulators, relief devices, and pressure sensors. A weather-induced failure of a gas pipeline can result in releases that threaten public safety and further contribute to climate change. On May 2, 2019, PHMSA issued another advisory bulletin to remind operators of the risks to pipeline facilities from large earth movement, including subsidence and erosion events that can be intensified due to climate change.⁵⁹ PHMSA issued an update to this advisory bulletin on June 2, 2022, noting recent incidents and accidents underscoring the risks described in Advisory Bulletin ADB–2019–02.⁶⁰ This most recent bulletin notes that changing weather patterns due to climate change can weaken soil stability, increasing the likelihood of earth movement damage to pipeline facilities.

PHMSA has also documented serious pipeline integrity threats from hurricanes in an advisory bulletin published on September 1, 2011, titled “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes.”⁶¹ This advisory bulletin notes that hurricanes can directly damage pipelines, cause

submerged pipelines to become exposed, or otherwise cause pipeline facilities to become a hazard to navigation. The advisory bulletin also noted that in 2005, Hurricane Katrina and Hurricane Rita caused extensive damage to onshore and offshore oil and gas production and transportation infrastructure in the Gulf of Mexico, which took substantial time and resources to contain and remediate. PHMSA expects more severe and frequent hurricanes will amplify the risk of damage to pipeline facilities, to the detriment of coastal communities, environments, and the reliability of the U.S. oil and gas industry.

Finally, these and other consequences of climate change have been, and are expected to continue to be, disproportionately borne by vulnerable populations in the United States—in particular by minority and low-income populations, outdoor laborers, children, and the elderly.⁶² Some communities of color may be uniquely vulnerable to climate change health impacts in the United States because they live in areas where the impacts of climate change (e.g., extreme temperatures and flooding) are likely to be the most significant, and because these communities tend to have limited adaptive opportunities due to a greater dependence on climate-sensitive resources (such as local water and food supplies), economic opportunities (e.g., seasonal labor), and limited access to social and information resources. The 2016 scientific assessment on the *Impacts of Climate Change on Human Health* similarly found that social determinants of health (e.g., access to healthcare, economic stability) are highly likely to contribute to climate change-related health impacts.⁶³ And insofar as gas transmission and gas gathering pipeline infrastructure is often located in the vicinity of socially vulnerable populations,⁶⁴ those populations would face the greatest risks in the event of a release from a gas pipeline damaged by climate change-induced extreme weather events.

C. Methane Emissions From Gas Pipeline Facilities

Most gas produced or consumed in the United States is transported by a gas

⁵⁴ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Southern Great Plains* at 1003–06 (2018).

⁵⁵ U.S. Global Change Research Program, *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II—Tribes and Indigenous Peoples* at 579 (2018).

⁵⁶ Eric S. Blake and David A. Zelinsky, NOAA National Hurricane Center, “National Hurricane Center Tropical Cyclone Report,” May 9, 2018, https://www.nhc.noaa.gov/data/tcr/AL092017_Harvey.pdf.

⁵⁷ Richard J. Pasch, Andrew B. Penny, and Robbie Berg, NOAA National Hurricane Center, “National Hurricane Center Tropical Cyclone Report: Hurricane Maria,” February 14, 2019, At page 7, https://www.nhc.noaa.gov/data/tcr/AL152017_Maria.pdf.

⁵⁸ PHMSA, “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,” 84 FR 14715 (Apr. 11, 2019) (Advisory Bulletin ADB–2019–01).

⁵⁹ PHMSA, “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,” 84 FR 18919 (May 2, 2019) (Advisory Bulletin ADB–2019–02).

⁶⁰ PHMSA, “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,” 87 FR 22576 (June 2, 2022) (Advisory Bulletin ADB–2022–01).

⁶¹ PHMSA, “Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes,” 76 FR 54531 (Sept. 1, 2011) (Advisory Bulletin ADB–11–050).

⁶² U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment—Executive Summary* at 6 (2016).

⁶³ U.S. Global Change Research Program, *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment* at 21 (2016).

⁶⁴ See Emanuel et al., “Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,” 5 *GeoHealth* (June 2021).

pipeline at some stage of its lifecycle. PHMSA is, by statute (49 U.S.C. 60101 *et seq.*), responsible for regulating the interstate transportation of gas by pipeline facilities, which can include the gathering, transmission, and distribution of natural gas as well as other gases regulated under parts 191 and 192.⁶⁵ Federal law, however, provides that the certified State agencies have jurisdiction to regulate purely intrastate gas pipeline facilities. Certain certified State programs may also inspect interstate pipelines, such as interstate distribution systems. Both Federal and State regulation of gas pipeline facilities has historically been directed toward the immediate, direct risks to public safety (and indirect risks to the environment) associated with the ignition of natural gas releases—less so on the direct threat to environmental risks, including those risks posed by un-ignited, released methane, that invariably contribute to climate change.⁶⁶

1. Gas Pipeline Facilities

PHMSA regulations cover several types of gas pipeline facilities, including gas gathering pipelines, gas transmission pipelines, gas distribution pipelines, LNG facilities, and UNGSFs.

Gathering Pipelines

A gas gathering pipeline is defined in Federal regulations at § 192.3 as a pipeline that transports gas from a production facility to a transmission pipeline or main. More generally, these pipelines “gather” gas from production facilities for transport to a gas processing plant for further transportation across transmission pipelines. The precise points where a gathering pipeline begins and ends are defined in §§ 192.8 and 192.9 and the first edition of American Petroleum Institute (API) Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines.”⁶⁷

Section 192.9(b) provides that offshore gas gathering pipelines are

generally subject to the same part 192 requirements as gas transmission pipelines. Section 192.8 also defines three types of regulated onshore gas gathering pipelines subject to part 192 requirements: Type A, Type B, and Type C gathering pipelines. Operators reported 8,290 miles of Type A pipelines, 3,078 miles of Type B pipelines, and 5,706 miles of offshore gathering lines in their 2021 annual reports. Type C gathering line operators will be required to submit their first annual report for calendar year 2022 in 2023; PHMSA estimates that there are approximately 90,000 miles of Type C gathering lines.⁶⁸ Type A and Type B gathering pipelines are located in Class 2, Class 3, or Class 4 locations. Type A gathering pipelines are higher-pressure pipelines and subject to most part 192 safety requirements applicable to gas transmission pipelines, while Type B gathering pipelines are lower pressure pipelines subject to a smaller subset of specific part 192 safety requirements listed in § 192.9(d). The Type C gathering pipeline designation was established in a final rule titled “Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation or Large, High-Pressure Lines, and Other Related Amendments” published on Nov. 15, 2021.⁶⁹ Type C gathering pipelines are located in Class 1 locations, have an outside diameter greater than or equal to 8.625 inches, and operate at high pressure.⁷⁰ These pipelines are subject to scaled safety requirements in § 192.9(e), with more part 192 safety requirements applicable as a function of the risk posed to public safety based on the diameter of the Type C segment (which affects the potential energy of a pipeline rupture and explosion) and its proximity to nearby populated structures. For example, § 192.9(e) provides that while all Type C lines are required to carry out a damage prevention program, leakage survey requirements only attach to either the largest (outside diameter

greater than 16 inches) Type C lines, or those Type C lines with smaller diameters (8.625 inches through 16 inches) near buildings intended for human occupancy.

Type A, Type B, and certain Type C gathering pipelines (namely, those Type C gathering pipelines that are installed, replaced, relocated, or otherwise changed after May 16, 2023) must comply with the design, construction, initial inspection, and initial testing requirements applicable to gas transmission lines, and must therefore be constructed from similar materials. According to annual reports submitted to PHMSA, gas transmission pipelines and Type A and Type B regulated onshore gathering lines are generally made from steel and, to a lesser extent, polyethylene plastic. An operator may also use two polyamide compounds, PA-11 and PA-12. Composite materials⁷¹ may be used with notification to PHMSA on a Type C gathering pipeline. PHMSA expects that most Type C gathering pipelines, which have operational characteristics similar to gas transmission and Type A regulated gas gathering pipelines, are made of steel, but Type C pipelines existing prior to May 16, 2023, may have been constructed with non-standard materials.

Transmission Pipelines

A gas transmission pipeline is defined in § 192.3 to include any pipeline, other than a gathering pipeline, that transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large-volume customer such as a gas power station or an LNG facility. In 2021, operators reported 301,524 miles of gas transmission pipelines on their annual reports. Additionally, a pipeline other than a gathering pipeline that operates at a hoop stress of 20% or more of the specified minimum yield strength (SMYS),⁷² or that transports gas within a storage field, is also classified as a gas transmission pipeline. An operator may also voluntarily designate a pipeline as a gas transmission pipeline that would otherwise meet the definition of a gas gathering pipeline or gas distribution

⁶⁵ Parts 191 and 192 govern not only natural gas, but also any “flammable gas, or gas which is toxic or corrosive.” See §§ 191.3 and 192.3 (definitions of “gas”). Consequently, the proposed revisions to parts 191 and 192 within this NPRM would apply not only to natural gas pipelines but also to other gas pipeline governed by parts 191 and 192.

⁶⁶ PHMSA acknowledges that in revising its Pipeline Safety Regulations over the years, it has identified environmental benefits of those efforts in much the same way that it has identified other benefits (e.g., reduced compliance cost for operators, equity, etc.) of those rulemakings. However, PHMSA submits those non-safety benefits were generally presented as secondary benefits of safety-focused regulatory amendments.

⁶⁷ API, *Recommended Practice 80: Guidelines for the Definition of Onshore Gas Gathering Lines* (Apr. 2000) (API RP 80).

⁶⁸ See PHMSA, Doc. No. PHMSA–2011–0023, “Regulatory Impact Analysis: Pipeline Safety: Expansion of Gas Gathering Regulation Final Rule” at 11, 15 (Nov. 2021) (Gas Gathering RIA).

⁶⁹ 86 FR 63266 (Gas Gathering Final Rule). Certain smaller-diameter Type C gas gathering pipelines are the subject of a temporary enforcement discretion whereby PHMSA has committed not to pursue enforcement action against those pipelines for alleged violations of certain part 192 safety requirements before May 17, 2024. See PHMSA, “Notice of Limited Enforcement Discretion for Particular Type C Gas Gathering Pipelines” (July 8, 2022), <https://www.phmsa.dot.gov/news/notice-limited-enforcement-discretion-particular-type-c-gas-gathering-pipelines>.

⁷⁰ See the pressure criteria in the second column of table 1 in § 192.8(c)(2).

⁷¹ “Composite materials” are defined in § 192.3 as materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

⁷² SMYS is defined in 49 CFR 192.3 to mean specified minimum yield strength, which is a measure of tensile strength. As an example, Trade B pipe made to API 5L specification has a specified minimum yield strength (SMYS) of 35,000 pounds per square inch (psi) 40 percent of SMYS (35,000 × 0.40) is 14,000 psi.

pipeline. Gas transmission pipelines are typically steel, larger diameter (6 to 48 inches), high-pressure lines (operating pressures generally between 200 and 1500 pounds per square inch) transporting large volumes of gas long distances.

Distribution Pipelines

A gas distribution pipeline is defined at § 192.3 as a pipeline other than a gas transmission pipeline or gathering pipeline. Distribution pipelines are typically a part of a distribution system that transports gas received from a transmission pipeline by a distribution center (often located at the so-called “city gate”), and then to homes and businesses through a network of gas mains and service pipelines.⁷³ A gas distribution service pipeline feeds gas to one or two customers, while a distribution main is the common source of supply for two or more service pipelines. In 2021, distribution operators reported 2,300,793 miles of gas distribution mains and service lines on their annual reports. While virtually all gas transmission piping is fabricated from steel, gas distribution pipeline materials vary depending on the vintage and usage. Modern systems are predominately polyethylene plastic and protected steel (*i.e.*, coated with corrosion-resistant materials and/or equipped with cathodic protection); older systems may contain cast-iron or bare (not protected) steel piping. Distribution pipelines made of copper, wrought iron, and non-polyethylene plastic also exist but are less common.

LNG Facilities

An LNG facility is defined in Federal regulations at 49 CFR part 193⁷⁴ as a gas pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing LNG. LNG means natural gas or synthetic gas having methane as its principal constituent, and which has been

changed to a liquid, thereby reducing the volume of the gas to facilitate storage and long-distance transportation. LNG facilities are subject to the safety requirements in part 193. LNG facilities include gas pipeline facilities that either change gas into LNG (liquefaction) or that change LNG back into a vapor or gaseous state (vaporization). LNG facilities also include transfer piping systems that transfer LNG between any of the following: liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than gas pipeline facilities. In 2021, operators reported 168 in-service LNG facilities on their annual reports.

Underground Natural Gas Storage Facilities

Finally, an UNGSF is defined at § 192.3 as a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including: (1) a depleted hydrocarbon reservoir; (2) an aquifer reservoir; or (3) a solution-mined salt cavern. In addition to the storage reservoir or cavern itself, an UNGSF includes: injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas. Most underground natural gas storage occurs in depleted natural gas reservoirs. UNGSFs are subject to specific safety requirements set forth in § 192.12.

2. Sources of Emissions From Gas Pipeline Facilities

Emissions of methane and other gases subject to PHMSA’s regulations under part 192 occur in all sectors of the natural gas industry—from production/extraction facilities, gathering pipelines, processing facilities (where the gas is made suitable for transportation and use), transmission pipelines, distribution pipelines, and end user facilities.⁷⁵ Emissions occur during

normal operation, routine maintenance, and abnormal conditions (such as incidents). Gas pipeline facilities emit methane and other gases from “fugitive emissions” from system upsets (incidents and abnormal operations that result in the release of gas); unintentional leaks from line pipe, flanges, valves, meter sets, and other equipment; and intentional releases (such as when a gas pipeline facility is blown down for repairs or maintenance or through pressure relief device operation as designed or configured). Older pipelines and pipelines known to leak based on their material (*e.g.*, legacy materials such as cast iron, wrought iron, unprotected steel, and certain historic plastics), design, or past operating and maintenance history are generally more susceptible to leaks.

The EPA compiles and publishes data on the magnitude and sources of methane emissions from gas gathering, transmission, and distribution pipelines and other gas pipeline facilities. The EPA has two complementary programs for characterizing GHG emissions such as methane: the Inventory of Greenhouse Gas Emissions and Sinks (Greenhouse Gas Inventory, or GHGI), and the Greenhouse Gas Reporting Program (GHGRP).

- The 2022 GHGI estimates a time series of total annual national-level GHG emissions across sectors of the economy using a large number of data inputs including GHGRP, research studies, and national and subnational activity data sets. The most recent final GHGI (2022 GHGI) includes estimates from 1990 through 2020.⁷⁶ The GHGI includes estimates of GHG emissions from sources including fossil fuel combustion, industrial processes, agriculture, and transportation. The GHGI is updated annually.

- The Greenhouse Gas Reporting Program (GHGRP) has, since 2010, collected facility-level emissions data from certain large GHG emission sources, fuel and industrial gas suppliers, and CO₂ injection sites in the United States including large suppliers or facilities that emit more than 25,000 metric tons of CO₂ equivalent per year.⁷⁷

For the 2020 reporting year, subpart W facilities in the GHGRP included 164 reports from distribution operators and 45 reports from gas transmission pipeline operators. However, GHGRP

⁷³ Under 49 U.S.C. 60105 and 60106, States may assume safety authority over intrastate gas pipelines through certifications and agreements with PHMSA. Currently, the District of Columbia, Puerto Rico, and all States except Alaska and Hawaii exercise safety oversight authority over all intrastate gas distribution pipelines within State lines. These State programs conduct regular inspections and enforce State safety regulations over intrastate distribution pipelines. See PHMSA’s State Programs website for more information: <https://www.phmsa.dot.gov/working-phmsa/state-programs/state-programs-overview> (last accessed Dec. 20, 2022).

⁷⁴ Part 193 requirements may change as a result of regulatory amendments proposed in a forthcoming notice of proposed rulemaking issued under RIN 2137–AF45. PHMSA’s references to part 193 within this NPRM—including the proposed amended regulatory text at its conclusion—reflect current regulatory text and organization.

⁷⁵ Although the evaluation of release data discussed in this section II.C.2 and subsequent sections is focused on the location, frequency, and severity of leaks on natural gas pipeline facilities, that analysis is largely applicable to leaks on other part 192-regulated gas pipeline facilities. Indeed, certain part 192-regulated gas pipeline facilities (*e.g.*, gas pipeline facilities transporting hydrogen gas) may be particularly susceptible to leaks because of (*inter alia*) the smaller size of hydrogen gas molecules compared to methane molecules of which natural gas is mostly composed.

⁷⁶ EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020* (Apr. 15, 2022) (2022 GHGI).

⁷⁷ In the GHGI, the EPA estimates that the global warming potential of 1 metric ton of CH₄ is equivalent to 25 metric tons of CO₂ over a 100-year time horizon. (40 CFR 98, Table A–1 to Subpart A of Part 98).

data is not congruent with the pipelines subject to PHMSA regulations. For example, the 45 gas transmission pipeline operators submitting reports under GHGRP for the 2020 reporting year correspond only to approximately $\frac{2}{3}$ of gas transmission pipeline mileage nationwide.⁷⁸ Additionally, certain entire sectors, such as the agricultural sector, are not required to report to the GHGRP. The creation of the GHGRP was provided for by Congress in the fiscal year 2008 Consolidated Appropriations Act (Pub. L. 110–161) and promulgated under section 114 of the Clean Air Act.⁷⁹ Data must be reported to EPA by March 31 of each year. Petroleum and natural gas industries, including natural gas distribution facilities, onshore natural gas gathering and boosting, onshore natural gas transmission pipelines (including compression), and LNG storage/terminal facilities are covered under 40 CFR part 98, subpart W.

The GHGI estimates for methane emissions are generally developed by multiplying an emissions factor by an activity factor. For example, for distribution main leaks, an emission factor in kg CH₄ per mile by material type is multiplied by mileage data by material type (an activity factor) from PHMSA annual reports. Each itemized emissions segment or source in the GHGI has its own emissions factor, in many cases derived from GHGRP data. EPA annually updates the methodology in the GHGI to improve accuracy and completeness.⁸⁰ The current GHGI quantifies emissions from leaks in pipelines using the following approaches and data:

- Gathering pipeline leaks. Emission factors are developed using year specific GHGRP data. GHGRP data are used as the activity factor as well. GHGRP data are reported by material type.
- Transmission pipeline leaks. Data from EPA/GRI 1996 were used to develop the emission factor. PHMSA mileage data are used as the national activity factor.
- Distribution pipeline leaks. Data from Lamb et al. 2015 were combined with EPA/GRI 1996 to develop the material-specific emission factors. PHMSA main mileage and service line count data are used as the national activity factor, by material type.

⁷⁸ One operator may submit multiple GHGRP reports if they operate multiple systems or in multiple states.

⁷⁹ 42 U.S.C. 7414.

⁸⁰ Refer to tables 3.6–2, 3.6–6, and 3.6–17 of Annex 36 of the 2022 GHGI for more information on the methodologies or data sources used by EPA to develop each emissions factor.

Recent research using modern leak detection equipment indicates that overall fugitive methane emissions from gas pipeline facilities may be significantly underestimated in current methane emissions estimates. The methodology of multiplying an activity factor (such as pipeline mileage) by an emissions factor to extrapolate an estimate of overall emissions for a given source is considered a “bottom-up” approach that can be contrasted with a “top-down” approach taking total emissions measured at larger (e.g., national) scales and attributing emissions to specific sources through modeling. Top-down approaches regularly estimate higher total emissions in the atmosphere than have been estimated by bottom-up approaches (sometimes referred to as the “top-down/bottom-up gap”). For example, recent analysis using top-down methods from the International Energy Agency (IEA) released in early 2022 found that global methane emissions from the energy sector are about 70% greater than the official statistics reported by national governments.⁸¹ IEA used satellite-based sensor technologies, atmospheric methane measurements, and data processing techniques to capture total emissions over large areas and attribute those emissions to facility-level sources, rather than by simply multiplying activity factors by bottom-up emissions factors. Other studies comparing the two approaches have consistently shown that bottom-up approaches may underestimate total U.S. methane emissions by 50% or more.⁸² One explanation suggested for the significant discrepancy in estimated emissions is that bottom-up methods under-sample large but infrequent emissions events such as malfunctions and venting, possibly due to the difficulty and risks associated with taking samples during such events.⁸³

⁸¹ IEA, Press Release, “Methane emissions from the energy sector are 70% higher than official figures” (Feb. 23, 2022), <https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higher-than-official-figures>. IEA’s analysis may underestimate the full extent of methane emissions as satellite data used by the organization do not provide complete coverage of all global oil and gas operations.

⁸² Zavala-Araiza et al., “Reconciling Divergent Estimates of Oil and Gas Methane Emissions,” 112 *Proceedings of the National Academy of Sciences of the United States of America* 11597–98 (Dec. 22, 2015); Lyon et al., “Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region,” 49 *Environmental Science & Technology* at 8147, 8154 (July 7, 2015); Alvarez et al., “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,” *Science* 186 (June 21, 2018).

⁸³ Brandt et al., “Methane Leakage from North American Natural Gas Systems,” *Science* 343, 345 (Feb. 13, 2014); Zavala-Araiza et al., 2015, at 15598;

Furthermore, as discussed below, recent research also indicates that potential under-estimation of pipeline facility emissions could be particularly pronounced in connection with distribution and gathering pipelines. EPA has recently proposed adjustments to its GHGRP data collection for reporting equipment leaks from natural gas distribution sources (including pipeline mains and services, below grade transmission-distribution transfer stations, and below grade metering-regulating stations) and for reporting emissions from equipment at onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.⁸⁴ Additional discussion of emissions factors for gas pipelines is available in the Preliminary RIA for this NPRM available in the rulemaking docket.

Methane Emissions Data—All Natural Gas Pipeline Facilities

The 2022 GHGI estimated annual net methane emissions from U.S. natural gas systems in 2020 to be 6,6,137 thousand metric tons (kt).⁸⁵ Gas transmission, gas distribution, transportation-related gas and LNG storage, and regulated gas gathering lines as determined in § 192.8 are regulated by PHMSA. On the other hand, exploration, production, gas processing plants, and Type R unregulated gas gathering lines are not regulated by PHMSA. Assuming approximately one third of gathering and boosting emissions are attributable to regulated gas gathering lines, approximately half of net methane emissions from natural gas systems are from PHMSA-regulated pipeline facilities. The sector classifications used in the GHGI may not correspond precisely with the regulatory definitions of different types of pipeline facilities in the Federal Pipeline Safety Regulations. In EPA’s GHGI, the gathering and

Lyon, et al., 2015, at 8147, 8155; Alvarez et al., 2018, at 183. The authors of the Brandt, Zavala-Araiza, and Lyon studies also suggest that this underestimation of emissions could be due to (or exacerbated by) incomplete activity factors that omit certain emissions source activities (such as inaccurate component counts or even the omission of entire facilities). Further, the authors of the Brandt study point to limited sample sizes and changing technologies as other potential sources of error in bottom-up emissions estimates.

⁸⁴ EPA, “Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule—Notice of Proposed Rulemaking” 87 FR 36920, 36927 (June 21, 2022).

⁸⁵ Natural gas systems include exploration, production, gathering, processing, transmission, storage, and distribution of gas. The 2022 GHGI inventory introduced estimates of post-meter emissions. Emissions from power generation are estimated elsewhere in the GHGI.

boosting sources include gathering and boosting stations (with multiple sources on site) and gathering pipelines. Those sources include PHMSA-regulated gas gathering lines, Type R gathering lines, and some pipelines and activities that are better described as production and not transportation.⁸⁶ The GHGI data cited in this section is for natural gas systems, and therefore would be covered under the regulatory classifications in part 192. The EPA definition is similar in principle to the definition of a gas “gathering line” in part 192, although it references some gas treatment processes that could be

classified as a “production operation” rather than as a gathering pipeline under § 192.9 and the first edition of API RP 80, and therefore not under PHMSA’s jurisdiction. However, for the purposes of estimating emissions from leaks and incidents on PHMSA-regulated gas gathering pipelines, PHMSA believes that the emissions rate associated with “pipeline leaks” from “gathering and boosting” piping as defined by EPA would not be significantly different than the emissions rate for gas gathering pipelines as defined by PHMSA.

While natural gas exploration and production (*i.e.*, the upstream sector) is

the single largest source category, approximately one-third of total methane emissions are attributed to transmission, storage, and distribution systems, and an additional one-fourth of total methane emissions is attributed to natural gas gathering and boosting systems. A summary of these high-level emissions estimates is shown in the table below and represent the net methane emissions⁸⁷ for 2020 from section 3.7 and annex 3.6 of the 2022 GHGI. These figures represent only methane emissions and do not include, for example, CO₂ emissions from compressor station engines.

2022 GHGI: 2020 NATURAL GAS SYSTEMS NET METHANE EMISSIONS

Source	Kt CH ₄	Percent
Exploration and Production (excluding gathering)	1,964	32
Gathering and Boosting	1,500	24
Processing Plants	494	8
Transmission, Storage, and LNG	1,625	26
Distribution	554	9
Total	6,137	100

Methane Emissions Data—Natural Gas Distribution Pipelines

The GHGI estimates that in 2020, approximately half of methane emissions from natural gas distribution systems was caused by leaks from and incidents on gas distribution line pipe. Leaks from customer meters, meter stations, and regulator stations comprise most of the remaining emissions. Recent studies indicate, however, that current methane emissions data likely significantly under-estimates methane

emissions from gas distribution pipelines. For example, a national study focusing on the natural gas distribution sector estimated emissions from mains that were five times larger than those in the GHGI estimate for 2017 estimates (0.69 million metric tons of methane vs. 0.14 million metric tons)⁸⁸ and by extension the GHGI estimate for 2020 as well (0.69 million metric tons of methane vs. 0.13 million metric tons).⁸⁹ The current methodology for calculating the emissions factors from natural gas

distribution main and service pipelines in the GHGI was most recently updated in 2016⁹⁰ and relies on a 1996 report by the U.S. EPA and the Gas Research Institute (GRI)⁹¹ and a 2015 study by Lamb et. al.⁹² The 2020 study by Weller et.al. attributed the differences to a larger number of leaks than previously estimated and better quantification of the largest leaks from the distribution sector (so-called “super-emitter” leaks), which contribute significantly to overall emissions.⁹³

2022 GHGI: 2020 NATURAL GAS DISTRIBUTION SYSTEMS EMISSIONS BY CATEGORY

Source	Kt CH ₄	Percent
Main Pipeline Leaks	132.0	23.8
Service Pipeline Leaks	70.8	12.8
Mishaps (<i>e.g.</i> , Incidents)	68.6	12.4
Meter/Regulator Stations	44.4	8.0
Customer Meters	235.4	42.5
Pipeline Blowdown	2.1	0.4
Relief Device Venting	1.2	0.2
Total	554.5	100

Note the PHMSA definition of a service pipeline in § 192.3 includes the customer meter in most configurations.

⁸⁶ 2022 GHGI, Pg. 3–90.

⁸⁷ Net emissions estimates include estimated emissions reductions from reported implementation of EPA Methane Challenge and Gas STAR best practices by operators in the production, transmission and storage and distribution sectors and estimated reductions from EPA regulatory requirements.

⁸⁸ Weller et al., “A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local

Distribution Systems,” 54 *Environmental Science & Technology* 8958, 8966 (June 10, 2020).

⁸⁹ EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020, Annex 3.6–1* (Apr. 15, 2022).

⁹⁰ U.S. EPA, “Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2014: Revisions to Natural Gas Distribution Emissions”. Pgs. 10–13. (April 2016). https://www.epa.gov/sites/default/files/2016-08/documents/final_revision_ng_distribution_emissions_2016-04-14.pdf.

⁹¹ EPA & Gas Research Institute, *Methane Emissions from the Natural Gas Industry* (June 1996) (the 1996 GRI/EPA Report).

⁹² Lamb et al., “Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States,” 49 *Environmental Science & Technology* 5161 (Mar. 31, 2015).

⁹³ Weller et al., 2020, at 8958–59.

Unlike natural gas transmission systems, the GHGI separately estimates emissions from natural gas distribution mains and service pipelines by construction material.⁹⁴ PHMSA has monitored trends in legacy pipe materials for years, as these materials pose safety risks.⁹⁵ The GHGI data demonstrates that replacing leak-prone pipe, such as aging cast iron, can have a significant effect in reducing methane emissions from gas distribution systems. Despite dramatically increased natural gas production and consumption between 1990 and 2019, methane emissions from natural gas distribution systems have fallen steadily from 1,819 kt CH₄ in 1990 to 554.5 kt CH₄ in 2020 (as quantified by GHGI). This reduction in methane emissions corresponds to a decline in cast-iron and cathodically unprotected steel pipe mileage over the same period. And while cast iron mains currently represent less than 1 percent of total distribution main miles—approximately 18,000 miles of cast iron or wrought iron distribution main remain in place as of 2021—leaks on such facilities account for approximately one-fifth of GHGI's

estimated total fugitive emissions from all natural gas distribution mains in 2020. Additionally, PHMSA incident report data shows that cast iron mains are vulnerable to integrity failures resulting in incidents; around 8 percent of the incidents that occurred on gas distribution mains between 2010 and 2021 occurred on cast iron mains. GHGI and PHMSA data, therefore, demonstrates that replacing leak-prone materials on gas distribution pipelines can reduce fugitive emissions and incidents and suggest that similar environmental and public safety benefits could be achieved by upgrading gas transmission and gas gathering pipelines made from materials known to leak. PHMSA and its predecessor agency, the Research and Special Programs Administration (RSPA), have identified replacement of cast iron and bare steel pipe as a policy priority for reducing gas distribution leaks and incidents for over two decades. Further, on November 15, 2021, the Bipartisan Infrastructure Law (Pub. L. 117–57) appropriated \$200 million per year for PHMSA's Natural Gas Distribution Infrastructure Safety and Modernization

Grants program, which provides grant funding to municipally or community-owned gas distribution pipeline facilities for the purposes of replacing legacy pipeline facilities.⁹⁶

Methane Emissions Data—Natural Gas Transmission and Storage

The GHGI estimates natural gas transmission pipelines in 2020 emitted 1,300 kt of methane emissions, excluding storage; however, the causes are very different than distribution. Leaks from natural gas transmission line pipe represent a small share of emissions estimated in the GHGI: only 3.3 kt of a total 1,504 kt of net methane emissions from the transmission and storage sector. As shown in the table below, vented and fugitive emissions (*i.e.*, leaks) from natural gas transmission compressor stations, compressors, and regulating and metering stations comprise a significant portion of total methane emissions from pipeline facilities. GHGI data on the natural gas transmission and storage segment reflects both onshore and offshore sources.

2022 GHG INVENTORY: 2020 NATURAL GAS TRANSMISSION METHANE EMISSIONS

Source	Kt CH ₄	Percent
Pipeline Leaks	3.3	0.3
Pipeline Venting (including blowdowns and upset venting)	221.3	17.0
Station Venting (including blowdowns)	168.9	13.0
Dehydrator Venting	2.6	0.2
Flaring	0.6	0.0
Pneumatic Devices	36.3	2.8
Compressor Station Fugitive Emissions	702.8	54.1
Compressor Exhaust	164.1	12.6
Total	1,300.0	100.0

Note: Pipeline venting includes releases from ruptures and other incidents.

The table below shows emissions from compressor stations on natural gas transmission pipelines in additional

detail. Emissions from generators includes emissions from natural gas

storage facilities dedicated to a compressor station.

2022 GHG INVENTORY: 2020 NATURAL GAS TRANSMISSION COMPRESSOR STATION METHANE EMISSIONS

Source	Kt CH ₄	Percent
Fugitive Emissions	145.1	14.0
Reciprocating Compressor	419.5	40.5
Centrifugal Compressor (Wet Seals)	57.0	5.5
Centrifugal Compressor (Dry Seals)	81.3	7.8
Engine Exhaust	148.8	14.4
Turbine Exhaust	1.6	0.2
Generator Engines (inc. Storage)	13.8	1.3
Generator Turbine (inc. Storage)	0.004	0.0
Station Venting	168.9	16.3

⁹⁴ 2022 GHGI, Annex 3.6.

⁹⁵ PHMSA, "Pipe Replacement Background" (Apr. 26, 2021), <https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background> (last accessed Dec. 20, 2022).

⁹⁶ See PHMSA, "Natural Gas Distribution Infrastructure Safety and Modernization Grants" (Aug. 2, 2022), <https://www.phmsa.dot.gov/grants/pipeline/natural-gas-distribution-infrastructure-safety-and-modernization-grants> (last accessed Dec. 20, 2022).

2022 GHG INVENTORY: 2020 NATURAL GAS TRANSMISSION COMPRESSOR STATION METHANE EMISSIONS—Continued

Source	Kt CH ₄	Percent
Total	1,035.8	100.0

Additionally, the table below shows emissions from natural gas storage facilities.⁹⁷

2022 GHG INVENTORY: 2020 NATURAL GAS STORAGE METHANE EMISSIONS

Source	Kt CH ₄	Percent
Station and Compressor Fugitive Emissions	24.5	7.6
Reciprocating Compressors	102.9	32.2
Storage Wells	11.3	3.5
Metering and Regulating (Transmission Interconnect)	75.3	23.5
Metering and Regulating (Farm Taps & Direct Sales)	17.5	5.5
Dehydrator Venting	4.5	1.4
Flaring	1.1	0.4
Engine Exhaust	22.7	7.1
Turbine Exhaust	0.2	0.1
Generators (inc. Transmission)	13.8	4.3
Pneumatic Devices	17.3	5.4
Station Venting	28.9	9.0
Total	319.9	100.0

Though the 2022 GHGI does not track relief and control device releases as a separate emissions source for natural gas transmission and storage facilities, PHMSA incident report data indicates that such releases are a significant contributor to methane emissions. A pressure relief device is designed to allow gas to escape from a pressurized system to protect the system from overpressurization. Relief devices and other pressure control devices are critical to the safe operation of a pipeline system when they function as intended. However, a poorly designed or poorly configured pressure relief device can result in releases of gas to the atmosphere larger than strictly necessary to protect pipeline integrity. Conversely, a relief device or control device that fails to release gas as designed or configured will not provide adequate protection from overpressurization and may rupture, presenting a hazard to public safety and the environment. Between 2010 and 2021, PHMSA incident report data yields that “malfunction of control/relief equipment,” including control

valves, relief valves, pressure regulators, and emergency shutdown device system failures,⁹⁸ was listed as the cause for 30% of incidents and 21% of unintentional gas emissions from reportable incidents on gas transmission pipelines. Approximately 95% of these incidents are reportable due to reported unintentional emissions exceeding 3 MMCF, although these incidents are occasionally reportable because repair costs or other monetary damages exceed the property damage criterion in § 191.3. Out of these 480 incidents, 114 involved the failure of a relief valve. The next most commonly involved component in these failures were emergency shutdown devices, which resulted in 54 incidents over this time period.

Recent studies also suggest that current methane emissions data likely underestimates emissions from natural gas transmission and storage facilities. The emission factor for transmission pipeline leaks in the GHGI is based on volume 9 of the 1996 GRI/EPA Report. The emissions factor is derived from the frequency of leak repairs reported on operators’ annual reports to RSPA and

self-reported leak measurements from distribution mains, both collected in 1991.⁹⁹ The authors of one study noted that the difficulty in accurately measuring abnormal “super-emitter” events from natural gas transmission and storage facilities using on-site measurements suggests that bottom-up methodologies underestimate emissions from “super-emitter” events, and consequently total emissions.¹⁰⁰ For example, the 1996 GRI/EPA Report relied on limited RSPA incident report data which did not even include a volumetric incident definition criterion as used under current PHMSA reporting requirements.¹⁰¹ The RSPA incident report form in 1991 similarly did not require operators to provide an estimate of release volume. While current methane emissions data attempts to address this concern by factoring in “super-emitter” estimates, this remains a source of uncertainty for any type of point-in-time measurement.¹⁰² Further, certain infrequent but significant incidents at UNGSFs such as the release of 86 billion cubic feet (BCF) of natural gas from the Aliso Canyon facility

⁹⁷ The nature and use of tankage as storage incidental to the movement of gas by pipeline dictates whether storage facilities are pipeline facilities subject to the jurisdiction of 49 U.S.C. 60101, *et seq.*

⁹⁸ See PHMSA, Form F 7100.2, “Incident Report -Gas Transmission and Gathering System” at section G6 (May 2022).

⁹⁹ EPA & Gas Research Institute, *Methane Emissions from the Natural Gas Industry, Volume*

9: *Underground Pipelines*. (June 1996). Pgs. 38 and 46.

¹⁰⁰ Zimmerle et al., “Methane Emissions from the Natural Gas Transmission and Storage System in the United States,” 49 *Environmental Science & Technology* 9374 (July 21, 2015).

¹⁰¹ See, e.g., RSPA Form F7100.2 (Rev. 3—1984), “PHMSA Gas Transmission & Gathering Incident Data—mid 1984 to 2001”, available at <https://www.phmsa.dot.gov/data-and-statistics/pipeline/>

distribution-transmission-gathering-Ing-and-liquid-accident-and-incident-data (last accessed Jan. 4, 2023).

¹⁰² See Alvarez et al., “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,” *Science* 186, Table 1 (June 21, 2018) (finding that bottom-up quantifications of methane emissions may underestimate natural gas transmission and storage emissions by nearly 30% when compared with top-down quantifications).

failure in 2015, the release of 6 BCF of natural gas from the Moss Bluff facility in 2004, and the release of 143 BCF of natural gas from the Yaggy storage field in 2001 demonstrate both the uncertainty in estimating methane emissions from UNGSFs and the potential for substantial methane emissions (which in turn result in public safety harms) from such facilities.¹⁰³

Methane Emissions Data—Gathering Pipelines

The GHGI estimates for “natural gas gathering and boosting” systems have

estimated fugitive emissions from line pipe leaks that are much higher than for natural gas transmission systems. As shown in the table below, the GHGI estimates 126.7 kt of methane emissions from pipeline leaks in natural gas gathering and boosting systems (estimated at 381,909 miles in the GHGI)¹⁰⁴ compared with 3.3 kt for natural gas transmission systems (302,252 miles). In the RIA for the 2021 Gas Gathering Final Rule, PHMSA estimated that there were approximately 426,000 miles of unregulated rural gas gathering pipelines,¹⁰⁵ in addition to the

17,064 miles of regulated offshore and onshore Type A and Type B regulated gas gathering pipelines reported by operators in 2021. Additionally, the EPA mileage estimate may include mileage that could be considered under § 192.8 to be production pipelines rather than gathering pipelines. The EPA mileage therefore provides an estimate of gathering pipeline mileage and resulting total emissions estimates from such facilities that may not accurately represent emissions from the subset of PHMSA-regulated gathering pipeline sources.

2022 GHG INVENTORY: NATURAL GAS GATHERING AND BOOSTING METHANE EMISSIONS

Source	Kt CH ₄	Percent
Station Combustion Slip	407.1	27
Station Compressors	306.9	20
Station Tanks	244.3	16
Station Pneumatic Devices	202.0	13
Pipeline Leaks	126.7	8
Station Yard Piping	93.3	6
Station Blowdowns	44.9	3
Station Dehydrator Vents and Leaks	25.7	2
Station Pneumatic Pumps	27.2	2
Pipeline Blowdowns	9.4	1
Station Flare Stacks	11.1	1
Station Separators	1.4	0
Station Acid Gas Removal Units	0.1	0
Total	1500.0	100

Note: Total includes Type R gas gathering pipelines and production operations not regulated under part 192.

Recent research also suggests that, as in the case of other gas pipeline facilities, current methane emissions data likely understates emissions from natural gas gathering pipelines. One study conducted in the New Mexico Permian Basin in 2022 estimated emissions from natural gas production and gathering facilities in that region that were 6.5 times larger than GHGI estimates.¹⁰⁶ In the study, methane emissions were estimated using a comprehensive aerial survey spanning 35,923 square kilometers (including over 15,000 kilometers of natural gas pipelines) over 115 flight days. This large sample size was intended to better

capture infrequent “super-emitter” events, and the study found that 50% of observed emissions were attributable to large emissions sources with average methane emissions rates greater than 308 kilograms per hour. Even as studies in the past few years have increasingly sounded the alarm that leaks from gathering pipelines and boosting stations are significant contributors to climate change, GHGI emissions factors for those facilities have *decreased* over the same time period due to changes in GHGRP inputs.¹⁰⁷ Moreover, studies aiming to improve gas gathering pipeline emissions factors with more accurate data (like one conducted on the

Utica Shale in 2020)¹⁰⁸ suggest that self-reported emissions information from GHGRP reporting on which GHGI emissions data for gathering pipelines is based may underestimate actual emissions rates. Any point-in-time measurement of methane emissions can miss large but infrequent events (particularly methodologies that use smaller sample areas such as ground-based approaches), thus underestimating total emissions when used to extrapolate beyond the sample area to an entire region.¹⁰⁹

¹⁰³ PHMSA, “Pipeline Safety: Safe Operations of Underground Storage Facilities for Natural Gas,” 81 FR 6334 (Feb. 5, 2016) (Advisory Bulletin ADB–2016–02).

¹⁰⁴ 2022 GHGI, Annex 36 Table 3.6–7.

¹⁰⁵ Gas Gathering RIA at 15; PHMSA, “Annual Report Mileage for Natural Gas Transmission and Gathering Systems,” (Aug. 1, 2022), <https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems> (last accessed Aug. 19, 2022).

¹⁰⁶ Chen et al., “Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey,” 56 Environmental Science & Technology 4317 (Mar. 23, 2022) (finding that “[m]idstream assets were also a significant

source [of emissions], with 29 ± 20 t/h [(metric tonnes per hour)] emitted from pipelines (including underground gas gathering pipelines) and 26 ± 16 t/h emitted from compressor stations without a well on site”).

¹⁰⁷ GHGI emissions factors for gathering pipeline leaks were identified as 354.7 CH₄/mile in 2017 but decreased to 288.5 in the 2022 GHGI. See 2022 GHGI, Annex 36 Table 3.6–2. See also Li et al., “Gathering Pipeline Methane Emissions in Utica Shale Using an Unmanned Aerial Vehicle and Ground-Based Mobile Sampling,” *Atmosphere* (July 5, 2020) (calling for improved gas gathering pipeline methane emissions factors for the Utica Shale region based on data from both aerial surveys and ground-based vehicle sampling); Chen et al.,

2022, at 4317–18 (observing that, while “uncertainty remains about the emissions rates in the Permian Basin”, recent studies conducted in that region “consistently find emissions significantly in excess of government estimates”).

¹⁰⁸ Li et al., “Gathering Pipeline Methane Emissions in Utica Shale Using an Unmanned Aerial Vehicle and Ground-Based Mobile Sampling,” *Atmosphere* (July 5, 2020).

¹⁰⁹ Chen et al., 2022, at 4321–22 (“[T]he clear impact of large emissions found by this study suggests that estimates from ground-based methane surveys may be underestimating total emissions by missing low-frequency, high-impact large emissions.”).

Methane Emissions Data—LNG Facilities

As shown in the tables below, the GHGI estimates that blowdowns account

for 80 percent of estimated methane emissions from LNG storage facilities, and nearly half of methane emissions from all LNG facilities.

2022 GHG INVENTORY: LNG STORAGE FACILITY 2020 METHANE EMISSIONS

Source	Kt CH ₄	Percent
Equipment Leaks, Compressors, Flares, etc	1.4	13
Blowdowns	8.4	80
Engine Exhaust	0.6	5
Turbine Exhaust	0.1	1

2022 GHG INVENTORY: LNG IMPORT TERMINAL 2020 METHANE EMISSIONS

Source	Kt CH ₄	Percent
Equipment Leaks, Compressors, Flares, etc	0.1	22
Blowdowns	0.2	33
Engine Exhaust	0.2	45
Turbine Exhaust	0.0	<1

2022 GHG INVENTORY: LNG EXPORT TERMINAL 2020 METHANE EMISSIONS

Source	Kt CH ₄	Percent
Equipment Leaks, Compressors, Flares, etc	4.0	53
Blowdowns	0.3	4
Engine Exhaust	1.4	18
Turbine Exhaust	2.0	26

Fugitive emissions represent the majority of estimated methane emissions from LNG import and export terminals. While LNG facilities are often designed with boil-off gas recovery systems to avoid routine continuous venting of natural gas during operations, methane regularly escapes from LNG facilities through compressor rod packing and valve leakage, incomplete combustion during flaring, and other various process venting sources.¹¹⁰ Similar to gas transmission facilities, additional emissions are attributable to releases from relief devices and O&M related venting. Likewise, fugitive emissions from gas treatment equipment at liquefaction plants are likely similar to those from comparable equipment on other pipeline or gas processing facilities.¹¹¹ Methane may also be lost to the atmosphere during pipe transfers of LNG to or from an LNG facility, whether through loading for transport or off-loading for storage or vaporization. Even if initially captured, boil-off gas and other fugitive emissions from LNG facilities may still be vented directly to the atmosphere without combustion

during normal operation.¹¹² And, as with any pipe transporting natural gas, the pressurized piping that runs throughout LNG facilities is susceptible to integrity failures and other incidents,¹¹³ including pipeline leaks that can precipitate explosions.¹¹⁴ For

¹¹⁰ API, *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* at 6–123 (Nov. 2021). For example, boil-off gas may be vented if the vapor generation rate exceeds the capacity of the boil-off gas compressors or the re-liquefaction unit. API's compendium estimates typical losses at 0.05% of total tank volume per day when boil-off gas is vented from an LNG storage vessel. *See also* Soraghan & Lee, "LNG explosion shines light on 42-year-old gas rules" *EnergyWire* (June 28, 2022), <https://www.eenews.net/articles/lng-explosion-shines-light-on-42-year-old-gas-rules/> (noting that an LNG terminal had reported several natural gas releases to the state Department of Environmental Quality, including one release of 180,000 pounds of methane in January 2022).

¹¹¹ *See, e.g.*, PHMSA, CPF No. 4–2022–051–NOPS, "In the Matter of Freeport LNG Development LP: Notice of Proposed Safety Order" at 3 (June 30, 2022), (describing the LNG release and natural gas vapor cloud that resulted from the June 8, 2022 incident at the Quintana Island LNG facility, which may have been caused by the overpressure and rupture of a segment of LNG transfer line between the facility's LNG storage tank area and its dock facilities).

¹¹² *See, e.g.*, "Algerian LNG Complex Explosion Caused by Gas Pipeline Leak," *Oil & Gas Journal* (Feb. 18, 2004). A gas pipeline leak was ultimately determined to be the cause of the Skikda, Algeria LNG terminal explosion on January 20, 2004, that killed 27 people, injured 74 others, and resulted in an estimated \$800 million–\$1 billion in damages to the Skikda port facilities, including the destruction

example, Cheniere reported that the Sabine Pass LNG terminal constituted approximately 40 miles of plant piping for its import facilities and an additional 285 miles of plant piping for its first four of six liquefaction trains,¹¹⁵ and the operator of the Cameron LNG terminal reported approximately 255 miles of piping in their liquefaction project consisting of three liquefaction trains.¹¹⁶ In addition, Freeport LNG similarly reported its liquefaction project's pretreatment and three liquefaction trains included approximately 192 miles of plant piping, providing ample opportunities for methane to escape during normal and emergency operations.

However, emissions from LNG facilities have proven difficult to estimate due to the limited availability of accurate, complete emissions data, with insufficient differentiation between intentional and fugitive emissions.¹¹⁷

of three of the LNG terminal's six liquefaction trains. *See also* Romero, "Algerian Explosion Stirs Foes of U.S. Gas Projects," *New York Times* (Feb. 14, 2004).

¹¹⁵ Cheniere. "Cheniere Energy Analyst/Investor Day." (Apr. 2014). Pgs. 12–13.

¹¹⁶ Cameron LNG. <https://cameronlng.com/lng-facility/economic-impact/>.

¹¹⁷ Oxford Institute for Energy Studies, *Measurement, Reporting, and Verification of Methane Emissions from Natural Gas and LNG*

Continued

¹¹⁰ API, *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* at 6–121 through 6–126 (Nov. 2021).

¹¹¹ API, *Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry* at 6–121 through 6–122 (Nov. 2021).

Bottom-up methodologies for estimating LNG emissions typically use generalized emissions factors averaged across the entire sector despite significant differences between suppliers and each step of the supply chain.¹¹⁸ Emissions estimates using this approach may apply a single emissions factor to all types of LNG facilities, even though the wave of recently built LNG export terminals could have little in common with an LNG peak shaver or storage facility. Developing accurate emissions estimates is also hampered by selection bias. Specifically, EPA currently uses data reported in accordance with 40 CFR part 98, subpart W (*i.e.*, GHGRP) to develop GHGI emissions factors for LNG facilities (with the exception of LNG storage facility blowdowns). However, operators of LNG facilities need only report emissions under subpart W if total emissions reach the reporting threshold of 25,000 metric tons of CO₂ equivalent per year. Many LNG storage facilities fall under that threshold, introducing uncertainty into aggregate emissions calculated using only a subset of LNG storage facilities.¹¹⁹

Further, even among those LNG facilities that report their emissions to EPA, there is a potential for great variation in emissions reported within and across reporting years due to small sample sizes: the small number of LNG facilities reporting emissions to EPA (only 5 storage facilities and 11 import and export facilities as of August 2022¹²⁰) make resulting methane emissions estimates susceptible to substantial year-to-year fluctuation and limit the predictive value of such estimates for subsequent years.¹²¹ Lastly, operators of LNG storage facilities are not required to report LNG storage blowdown emissions under

GHGRP—instead, GHGI estimates for LNG storage blowdown emissions consist of generalized data based on a 1996 study of blowdown emissions on gas transmission compressor stations and UNGSFS.¹²²

D. The Need for Updating PHMSA Regulations To Incorporate Advanced Leak Detection Programs To Reduce Unintentional Releases From Gas Pipelines

PHMSA's regulations have historically prioritized addressing public safety risks posed by ignition of instantaneous, large-volume releases or accumulated gas. This focus on public safety is vital and can support PHMSA's renewed and expanded commitment to addressing environmental risks as well. However, current regulations can allow leaks of methane and other gases from gas gathering, transmission, and distribution pipeline facilities to continue undetected and unrepaired for extended periods of time.¹²³ This approach therefore foregoes the emissions reduction potential of commercially available, advanced leak detection technologies and practices within integrated ALDPs. This historical approach also forgoes opportunities for timely identification and remediation of leaks from gas pipelines that can develop into catastrophic incidents. State and voluntary industry efforts to improve leak detection and repair on gas pipelines are emerging, but are insufficient to reduce unintentional emissions of methane and other gases without PHMSA regulations that support and backstop those efforts.

1. PHMSA Regulations Pertinent to Unintentional Releases of Methane and Other Gases

PHMSA's current regulatory requirements pertaining to gas pipeline leak detection, repair, maintenance, and reporting reflect a focus on public safety risks from ignition of instantaneous, large-volume releases or accumulated gas while treating risks to the environment as less important. PHMSA maintenance requirements at part 192, subpart M explicitly require only a subset of unintentional releases from gas pipelines—namely those unintentional

releases thought to create an actual or probable harm to public safety—need be identified, repaired, or reported. Nor do those maintenance requirements in the subpart M regulations include explicit requirements for the replacement or remediation of pipes known to leak based on material, design, or past operating and maintenance history.¹²⁴ And PHMSA IM regulations at part 192 subparts O (gas transmission pipelines) and P (gas distribution pipelines) allow considerable operator discretion in determining which leaks merit repairs and the timing of those repairs. PHMSA reporting requirements at part 191 similarly are calibrated to provide information regarding instantaneous, large-volume releases rather than granular data on operator leak detection and repair efforts, or the releases of gas from those leaks.

Gas Pipelines Generally

Part 192, subpart M contains minimum maintenance requirements for gas gathering, transmission, and distribution pipelines.¹²⁵ Gas transmission (§ 192.706), distribution (§ 192.723), offshore gas gathering, and Type A, Type B, and certain Type C gathering (§§ 192.9 and 192.706) pipeline operators must perform periodic leakage surveys. When leaks are discovered, both their severity and the operating conditions of the pipeline are used to determine whether and when a repair is performed. PHMSA's subpart M requirements contain broad language at § 192.703(c) mandating repair of all “hazardous leaks . . . promptly.” However, subpart M neither

Trade: Creating Transparent and Credible Frameworks at 51 (Jan. 2022).

¹¹⁸ See Roman-White et al., “LNG Supply Chains: A Supplier-Specific Life-Cycle Assessment for Improved Emission Accounting,” *ACS Sustainable Chemistry & Engineering* at 10857, 10861 (2021).

¹¹⁹ EPA, Memorandum, “Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment” at 2–3 (Apr. 2019). While EPA identified between 94–98 LNG storage facilities as active each year from 2011–2017, only 8 such facilities reported emissions under Subpart W during that timeframe.

¹²⁰ See EPA, “GHGRP Petroleum and Natural Gas Systems,” <https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems#emissions-table> (last accessed March 16, 2023).

¹²¹ For example, in 2016, one LNG storage facility was responsible for more than 82% of all LNG storage facility methane emissions and one LNG import terminal was responsible for more than 95% of all LNG terminal methane emissions reported to EPA under Subpart W. EPA, Memorandum, “Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment” at 3–8 & Tables 5, 8 (April 2019).

¹²² EPA, Memorandum, “Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2017: Updates to Liquefied Natural Gas Segment” at 1 (April 2019).

¹²³ PHMSA notes that the limitations of current part 191 and 192 regulations for meaningful and timely identification, repair, and reporting of leaks discussed in this section II.D. may be particularly acute in connection with the pipeline transportation of gaseous hydrogen, which is a much smaller molecule (with potentially greater leakage potential) than methane.

¹²⁴ An exception is that part 192, subpart M acknowledges cast-iron piping's susceptibility to leakage and contains provisions focused on a single mechanism (graphitization-derived corrosion) for development of leaks, and then only after indicia of that mechanism have emerged. Specifically, § 192.489(a) requires replacement of each segment of cast iron or ductile iron pipe with general graphitization (a type of corrosion) that could cause a fracture or leak. Section 192.489(b) similarly requires replacement, repair, or internal sealing for localized graphitization on cast and ductile iron pipeline segments that could result in leakage.

¹²⁵ Certain part 192 regulations will be revised on codification of a recent PHMSA rulemaking that will become effective on May 24, 2023. See PHMSA, “Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments—Final Rule,” 87 FR 52224 (Aug. 24, 2022) (RIN2 Final Rule). PHMSA's references to part 192 within this NPRM—including the proposed amended regulatory text at its conclusion—reflect the regulatory text and organization as amended by the RIN2 Final Rule unless otherwise noted. The RIN2 Final Rule contains enhanced repair criteria that can affect leak repairs, but the requirements are generally directed toward phenomena (cracking, corrosion-induced metal loss, dents) distinct from the detection, grading, and repair of all leaks as proposed in this NPRM.

defines a “hazardous” leak nor provides guidance on what exactly constitutes a “prompt” repair of such leaks. Although § 192.1001 describes a “hazardous leak” only in terms of an existing or probable hazard to persons or property (and not the environment), that regulatory definition applies only to the gas distribution system IM requirements in part 192, subpart P. The § 192.703(c) repair mandate is also inapplicable to most Type C gas gathering pipelines.¹²⁶

Part 191 reporting requirements similarly reflect PHMSA’s historical focus on public safety risks from ignition of instantaneous, large-volume releases or accumulated gas.¹²⁷ Incident reports for gas distribution (Form F7100.1), transmission and part-192 regulated gathering (Form F7100.2), and Type R gathering pipelines (Form F7100.2.2) provide limited information regarding unintentional releases, as only unintentional releases of at least 3 MMCF need be reported. And while annual reports for gas distribution (Form F7100.1–1), transmission and part-192 regulated gathering (Form F7100.2–1), and Type R gathering pipelines (Form F7100.2–3) include information on the number of leaks repaired in the preceding calendar year, the instructions for those annual report forms expressly exclude reporting of repairs on a broad category of leaks: releases that can be corrected by “lubrication, adjustment, or tightening” are not considered “leaks” for annual reporting of repairs.¹²⁸ The instructions for annual reports other than for gas distribution pipelines also do not require reporting of repairs of any leaks other than leaks that are hazardous; and the instructions for all annual report forms characterize leaks as “hazardous” with respect to public safety, omitting mention of hazards to the environment. Further, none of PHMSA’s annual reports require operators to submit information on either the total number of leaks detected in the reporting period,

the rolling tally of all unrepaired leaks, or estimated emissions associated with leaks during the reporting period.

Lastly, only gas transmission pipelines are required to provide geospatial data on their pipeline systems in accordance with the NPMS requirements at 49 U.S.C. 60132 and 49 CFR 191.29. Gas distribution and gathering pipelines have no requirement to provide geospatial data for NPMS.

Part 192—Regulated Gas Gathering Pipelines

Operators of offshore gas gathering, Type A, Type B, and certain Type C gathering pipelines must comply with the leakage survey requirements (at § 192.706) applicable to gas transmission pipelines and repair any hazardous leaks detected (per § 192.703). However, most Type C gathering pipelines—specifically, those with an outer diameter between 8.625” and 16” not near an occupied building—are, pursuant to § 192.9(f)(1), not subject to any part 192 leakage survey and repair requirements, whether for “hazardous” leaks or any other leaks. Additionally, only offshore gas gathering and Type A gathering pipelines are subject to other subpart M maintenance requirements, including right-of-way patrols (§ 192.705), general transmission pipeline requirements for making permanent or temporary repairs (§ 192.711), and recordkeeping (§ 192.709). Type B and Type C gathering pipelines need only comply with the specific requirements listed in § 192.9(d) and (e), which do not include patrol, repair, and recordkeeping requirements.

Gas Transmission Pipelines

All gas transmission pipelines are subject to maintenance requirements at part 192, subpart M. Section 192.706 requires gas transmission operators to perform leakage surveys on most gas transmission pipelines at least once every calendar year. However, that provision does not require the use of leak detection equipment for those leakage surveys. Leak detection equipment is only required if a gas transmission pipeline is not odorized in accordance with § 192.625 and the pipeline is located in a Class 3 or Class 4 location; otherwise, leak detection can be by human senses only, such as visual observation of dead vegetation or blowing debris. Operators required to conduct a leakage survey with leak detection equipment must do so at least twice each year in Class 3 locations, and at least four times each calendar year in Class 4 locations.

In addition to leakage surveys, § 192.705 requires operators of gas transmission pipelines to have a patrolling program to monitor conditions on and adjacent to pipeline rights-of-way. These patrols are visual surveys, commonly performed using aircraft, and are intended to find leaks and other conditions affecting the safety and operation of the pipeline. Patrols commonly identify potential or current pipeline integrity threats caused by external changes, including construction, excavation, blasting, earth movements, and flooding. Information gathered from these patrols can prevent further damage to the pipeline or target leakage surveys or integrity assessments to locations that may have been damaged. This can prevent leaks, potentially fatal incidents, or damage that could result in shutdowns and maintenance-related releases of methane and other gases to the atmosphere. For example, if an operator spots construction activity along the line, they can dispatch personnel to observe construction to minimize the risk of excavation-related damage to the pipeline. According to incidents reports submitted to PHMSA, such excavation damage is a leading cause of incidents that result in injuries and fatalities and pipeline breaks with very high emissions rates. The patrol frequency depends on the class location of the pipeline, the pipeline’s diameter, operating pressure, terrain, weather, and other relevant factors. Gas transmission pipeline operators must perform patrols at least four times each calendar year in Class 4 locations, at least twice each calendar year in Class 3 locations, and at least once each calendar year in Class 1 and Class 2 locations. If the pipeline is located at a highway or railroad crossing in a Class 1 or Class 2 location, the minimum patrol frequency is increased to at least twice each calendar year. In Class 3 locations, the minimum patrol frequency at highway and railroad crossings is four times each calendar year.

As explained above, § 192.703(c) requires all transmission operators to repair leaks that are “hazardous” to public safety “promptly”—but PHMSA regulations contain few guardrails as to what “promptly” means. Repair requirements at § 192.711 require that operators take immediate temporary measures for leaks that impair the serviceability of a steel transmission pipeline operating above 40 percent of SMYS if a permanent repair is not feasible.

Section 192.711(b) requires that permanent repair be made as soon as feasible or as specified under the

¹²⁶ Only ca. 20,000 miles of the ca. 91,000 miles of Type C gas gathering pipelines are subject to § 192.703(c). PHMSA, Doc. No. PHMSA–2011–0023–0488, “Regulatory Impact Analysis for Gas Gathering Final Rule” at 11, 15 (Nov. 2021).

¹²⁷ PHMSA annual and incident forms and instructions discussed in this paragraph can be found on PHMSA’s website at <https://www.phmsa.dot.gov/forms/operator-reports-submitted-phmsa-forms-and-instructions>.

¹²⁸ PHMSA annual reporting requirements for part 193-regulated LNG facilities contain a similar exception from leak reporting requirements. See PHMSA, Form 7300.1–3, “Annual Report Form for Liquefied Natural Gas Facilities (Oct. 2014); PHMSA, Instructions for Form 7300.1–3 at 4 (Oct. 2014) (stating that “a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak”).

operators' IM program under subpart O but does not specify when permanent repairs are necessary.¹²⁹ Like the general repair requirement in § 192.703, these requirements frame leak repair obligations in terms of public safety risks and use ambiguous language ("as soon as feasible") to describe the timing of any repair obligations. In recognition of this regulatory gap, PHMSA has referenced the GPTC Guide in guidance and letters of interpretation on how operators should comply with these provisions of part 192.¹³⁰

Subpart O requirements similarly provide little direction on how gas transmission pipelines that are located in HCAs¹³¹ must manage leak detection and repair, instead giving operators considerable discretion to determine when and how they address leaks on their pipelines. Subpart O requires operators to identify, prioritize, assess, evaluate, repair, and validate the integrity of their pipelines that have the potential to cause injury or death in the event of a failure. In addition, operators must measure IM plan performance to support continual improvement of their programs. Operators of gas transmission pipelines subject to the IM regulations may develop IM plans reflecting idiosyncratic choices regarding identification of specific integrity risks

to their pipelines, selection of proper assessment tools; periodic assessment of the pipe for anomalies, and procedures for taking prompt action to address and repair anomalous conditions discovered through pipeline integrity assessments. Additionally, the subpart O regulations do not explicitly require operators to repair all leaks; operators can determine the precise timing of "prompt" repairs based on the operator's evaluation of risk to public safety. Further, § 192.93 provides operators up to 6 months from the date that an integrity assessment was performed to confirm discovery of an anomalous condition. Repair criteria at § 192.933 require that anomalous conditions posing the greatest risks to public safety be repaired immediately, but other anomalies that an operator determines pose less significant public safety risks need to be repaired within a year of discovery, or only monitored during subsequent risk assessments and integrity assessments for any change that may require remediation. Section 192.935 directs operators to take additional measures beyond those required elsewhere in part 192 to prevent, and mitigate the consequences of, pipeline failures in HCAs, but that provision identifies enhanced leak detection and monitoring programs as merely one potential item on a menu from which operators may choose in order to meet this requirement.¹³²

Gas Distribution Pipelines

Distribution pipelines are subject to select part 192, subpart M maintenance requirements. Section 192.721 requires operators to patrol distribution mains at frequencies that consider the severity of the conditions that would cause failure or leakage, and the consequent hazard to public safety. Distribution mains subject to physical movement or external loading that could fail or leak must be patrolled at least twice each calendar year if located outside of business districts, and at least four times every calendar year if located within business districts. Distribution leakage survey requirements are defined in § 192.723. In business districts, operators must conduct leakage surveys of distribution pipelines with leak detection equipment at least once every calendar year. These surveys must include testing the atmosphere in utility manholes, at cracks in the pavement and sidewalks, and at other locations, providing opportunities to find leaks. Outside of business districts, operators must

perform leakage surveys using leak detection equipment as frequently as necessary, but not less than once every 5 calendar years. Gas distribution operators are subject to repair requirements for hazardous leaks at § 192.703, but that requirement provides no specific guidance on repair timelines and fails to mention environmental risks.

The distribution IM program (DIMP) regulations in subpart P require distribution pipeline operators to identify, prioritize, assess, evaluate, repair, and validate the integrity of gas distribution pipelines that have the potential to cause injury or death in the event of a leak or failure. Section 192.1007 requires operators to demonstrate an understanding of their gas distribution systems based on reasonably available information. Operators then must apply the knowledge acquired through reasonably available information to identify threats to the integrity of their gas distribution systems. Threats can include a variety of phenomena: corrosion, excavation damage, vehicular strikes, poorly fitting connections, and other threats. Operators must evaluate and rank the risk to their systems from those threats, and then identify and implement measures to address those risks. DIMP regulations require operators to periodically (at least once every 5 years) evaluate the threats, risks, and results of the performance measures to gauge the effectiveness of their DIMPs in controlling each threat. And § 192.1007(d) explicitly requires distribution pipeline operators to either repair all leaks when found or have an "effective leak management program." However, subpart P prescribes few specific requirements for those leak management programs or criteria for determining their effectiveness, requiring a distribution pipeline operator only to monitor (as a performance measure for evaluating a DIMP), the number of leaks it eliminates or repairs; to categorize such leaks by cause, material; to determine whether they are "hazardous"; and to report such measures annually to PHMSA. Indeed, the preamble to the 2009 final rule codifying subpart P merely suggested that each operator "should develop a program based on their knowledge of their pipeline system" with the GPTC Guide identified as an aid in developing such a program.¹³³

¹²⁹ The RIN2 Final Rule will amend § 192.711(b) by replacing the existing requirement that permanent repairs of safety-adverse conditions on certain onshore gas transmission pipelines must be made "as soon as feasible" with a cross-reference to a new § 192.714 prescribing repair schedules set forth in an industry standard. See 87 FR at 52271 (introducing a new § 192.714 referencing ASME/ANSI B31.8S-2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines* at section 7, Figure 4 (Jan. 14, 2005)). However, those repair schedules—which are intended for "anomalies and defects" consisting of dents, corrosion metal loss, and cracking rather than leaks—contemplate that some repairs may not be required for years. The RIN2 Final Rule does not disturb the existing requirement to effectuate permanent repairs "as soon as feasible" for other part 192-regulated gas pipelines not subject to subpart O IM requirements.

¹³⁰ See, e.g., PHMSA, "Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators" (2013) at 2 (directing larger distribution pipeline operators to refer to GPTC guidelines); PHMSA, Interpretation Response Letter No. PI-93-009 (February 11, 1993) (recommending public stakeholder consult the GPTC Guide for further determination of instruments and techniques to be used in certain leak detection activities); see also PHMSA, Interpretation Response Letter No. PI-99-0105 (December 1, 1999) (stating that the GPTC Guide "is a document endorsed by us which contains information and some methods to assist the gas pipeline operator in complying with the regulations contained in 49 CFR part 192").

¹³¹ Subpart O contains IM requirements for transmission pipelines in HCAs. Annual reports submitted by operators in 2020 yields that only 7% (ca. 21,000 miles) of the 301,000 miles of gas transmission pipelines are subject to IM requirements at subpart O.

¹³² Amendments to subpart O requirements pursuant to the RIN2 Final Rule will not disturb the pertinent requirements of that subpart described above.

¹³³ PHMSA, "Pipeline Safety: Integrity Management for Gas Distribution Pipelines—Final Rule," 74 FR 63905, 63917 (Dec 4, 2009). PHMSA is undertaking a complementary rulemaking under RIN 2137-AF53 ("Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety

2. Shortcomings of Current PHMSA Regulations in Addressing Unintentional Releases From Gas Pipelines

PHMSA regulations pertinent to leaks from gas pipelines focus on risks to public safety posed by ignition of instantaneous, large-volume releases or accumulated gas from gas pipeline facilities—an approach that is vital for protecting public safety but that foregoes opportunities to address environmental harms, including methane emissions' contribution to climate change. This approach has proven unsuccessful in timely identification and remediation of leaks that can have a substantial impact on the environment or even evolve into incidents posing catastrophic risks to public safety.

As explained above, part 192 subpart M maintenance requirements contain only a single repair requirement specific to leaks, which is applicable only to some part 192-regulated gas gathering, transmission, and distribution pipelines: § 192.703(c)'s requirement that “hazardous leaks” be repaired “promptly.” However, the term “hazardous leak” is nowhere defined in subpart M. Rather, what other limited evidence there is in PHMSA regulations elaborating on the meaning of “hazardous leak” pertains either to entirely different elements of part 192 (specifically, the § 192.1001 definition of “hazardous leak” within DIMP requirements in subpart P) or part 191 reporting requirements.¹³⁴ These regulatory provisions both describe “hazardous leak” with respect to potential or present risks to public safety; they are silent regarding risks to the environment.

Similarly, subpart M does not elaborate on the requirement that all hazardous leaks be repaired “promptly.” Section 192.711 allows operators to repair hazardous leaks and other conditions as soon as feasible for non-IM repairs, and as prescribed by § 192.933(d) for IM repairs. If a permanent repair is infeasible, § 192.711

merely requires that any temporary measure addresses public safety, again excluding the environment from explicit consideration.

Part 192 nowhere specifies remote or continuous monitoring for pipeline leaks apart from a recent limited requirement pertaining to detection of ruptures (rather than leaks) on certain new gas transmission pipelines with rupture mitigation valves.¹³⁵ Frequencies of leakage survey (§ 192.706) and patrol (§ 192.705) requirements are generally keyed to location and the likelihood of nearby people—proxies for risks to public safety but not the environment. Consequently, the majority of part 192-regulated gas transmission and some part 192-regulated, onshore gathering mileage in the United States (in particular, Types A and B gathering pipelines in more populated areas, and a minority of Type C lines¹³⁶) need only have annual leakage surveys, with as long as 15 months between surveys. The default leak detection survey periodicity for gas distribution pipelines outside of business districts is only once every 5 years. Similarly, PHMSA regulations at subpart M allow gas transmission and select part 192-regulated gathering pipeline mileage to have right-of-way patrols only once a year, if at all. Finally, patrols on gas distribution pipelines inside business districts are required twice a year.

Subpart M maintenance requirements governing the use of leak detection equipment also reflect the same historical focus on acute public safety risks. Subpart M regulations are silent on specific technologies or equipment operators should employ in their leak detection surveys. For example, leakage surveys on gas distribution lines, certain regulated gathering lines, and unodorized transmission pipelines in Class 3 and Class 4 locations must be performed with leak detection equipment—but part 192 neither requires particular technologies, nor establishes performance standards for leak detection equipment. Leakage surveys on other gas transmission pipelines (e.g., odorized lines and all pipelines in Class 1 and Class 2 locations) and patrols of pipeline rights-of-way can rely entirely on human

senses such as smell or sight, which are imprecise and substantially limited in their effectiveness. Evidence of a leak detectible by human senses includes dead vegetation caused by natural gas displacing oxygen in the soil, blowing soil, bubbling water, or noise. However, it may take a long time for evidence of a gas leak on vegetation to appear visibly from the air. Further, the reliability of vegetation surveys is inconsistent and depends heavily on soil and climate conditions, the characteristics of the vegetation, the time of year, and other factors. For example, the impacts of gas leaks on vegetation may not be visible during seasonal or climate conditions that produce dead vegetation, and in some soil conditions gas can temporarily increase vegetation growth. Finally, vegetation surveys are ineffective in areas with no or sparse vegetation, such as paved areas, particularly rocky areas, or deserts. PHMSA is not aware of research on the effectiveness of vegetation surveys versus instrumented surveys in general, however operators who begin performing instrumented surveys (such as the aerial survey examples described in section II.D.4) generally report more leaks discovered using instrumented surveys.

Additionally, PHMSA's IM regulations do not require identification and remediation of all leaks. PHMSA's IM regulations apply to about 7 percent of gas transmission pipelines.¹³⁷ And no part 192-regulated gathering pipelines (even Types A and C pipelines with operating characteristics and threats to public safety and the environment comparable to transmission lines)¹³⁸ are subject to any IM requirements. IM requirements also reflect a historical focus on identifying, preventing, and remediating risks to public safety from large-volume, instantaneous releases or accumulated gas rather than environmental harms. While the gas transmission IM regulations at subpart O oblige some transmission operators to find and eliminate pipeline anomalies posing risks to public safety, those regulations do not require repair of all leaks discovered and allow for substantial delay in the evaluation and subsequent repair of leaks that operators

Initiatives”) responding to congressional mandates in title II of The PIPES Act of 2020 directing PHMSA to, among other things, amend its subpart P distribution IM program requirements. PHMSA expects that the leak detection, grading, and repair requirements for gas distribution pipelines proposed herein would reinforce any changes to subpart P proposed in that rulemaking.

¹³⁴ See, e.g., PHMSA, Form F7100.1-1 Instructions (May 2021) (defining hazardous leaks as those representing an “existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous”). The instructions for annual report forms for other gas pipeline facilities contain similar language.

¹³⁵ PHMSA, “Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards—Final Rule,” 87 FR 20940, 20985 (Apr. 8, 2022) (introducing a new § 192.636).

¹³⁶ Only ca. 20,000 miles of the ca. 91,000 miles of Type C gas gathering pipelines are subject to § 192.706 leakage survey requirements. PHMSA, Doc. No. PHMSA–2011–0023–0488, “Regulatory Impact Analysis for Gas Gathering Final Rule” at 11, 15 (Nov. 2021).

¹³⁷ The effectiveness of its IM regulations for gas transmission pipelines at subpart O relies on operators' identification that those requirements apply—which is not a given. See NTSB, Pipeline Accident Brief 13–01, “Rupture of Florida Gas Transmission Pipeline and Release of Natural Gas” (Aug. 13, 2013) (finding that a gas transmission pipeline operator's exclusion of a segment from its IM plan due to mischaracterization of a Class 1 location contributed to a subsequent rupture).

¹³⁸ See Gas Gathering Final Rule, 87 FR at 6367–68, 63278–79 and 63282–84.

(largely at their discretion) consider not to pose acute public safety risks. DIMP regulations require gas distribution pipeline operators to have an “effective leak management program,” but those regulations provide few standards regarding what constitutes an “effective” program and can instead give considerable deference to an operator’s discretion regarding which leaks are repaired and when. Further, neither subparts O nor P require operator IM plans to consider replacement or remediation as a preventative or mitigative measure for pipe materials known to leak, despite data demonstrating that cast iron, wrought iron, unprotected steel, and certain plastic pipelines are more susceptible to leaks and other losses of pipeline integrity. PHMSA’s IM regulations are also not designed to address leaks with low release rates that persist for a long period of time, which can make significant contributions to climate change.

PHMSA part 191 reporting requirements also reflect a narrow focus on public safety risks rather than environmental harms such as the contribution of methane leaks to climate change, or environmental degradation from the release of other flammable, toxic or corrosive gases. Incident reporting requirements are expressed in terms of personal injury, commercial harm, property damage, or minimum release volumes that are far too high (3 MMCF) to capture any but the largest unintentional leaks from pipeline facilities—corresponding to a volumetric release rate of 340 cubic feet per hour (CFH) or more over a one-year period. Although annual reports submitted to PHMSA contain information on all leaks repaired each year, the instructions for those annual reports explicitly discourage reporting of leaks that can be eliminated by “lubrication, adjustment or tightening” on the narrow presumption that such releases were not necessarily hazardous from a public safety perspective. Operators are also not required to submit in their annual reports the total number of leaks—of any type—detected in the reporting period; the number of outstanding unrepaired leaks from year-to-year; or estimated emission volumes from any category of detected leaks.

Finally, the exclusion of all gas gathering pipelines from NPMS reporting requirements inhibits PHMSA, State regulators, operators, and members of the public from knowing the location and operating characteristics of pipelines. Such knowledge would help identify and remediate leaks and avoid excavation damage. Although all part

192-regulated gathering pipelines are subject to damage prevention requirements of § 192.614, those requirements are not reinforced by the NPMS requirements identifying the precise location of pipeline infrastructure.

3. Real-World Consequences of Delayed Repair and Prolonged Releases From Leaks on Gas Pipelines

The shortcomings of existing regulations pertaining to leak detection and repair described above are not abstract risks; operators currently allow leaks from gas pipelines to continue emitting methane and other gases for extended periods of time, thereby threatening the environment as well as public safety and human health.

Infrequent leak detection and patrol periodicities provide extended time intervals within which leaks can develop and worsen, thereby resulting in prolonged methane and other emissions to the atmosphere. Infrequent leak detection and patrol periodicities also entail increased public safety risks. Specifically, PHMSA’s regulations have long recognized the safety risk associated with potential ignition of leaks, as evidenced by heightened leak surveying and maintenance requirements throughout part 192 for pipelines located in areas where buildings intended for human occupancy are more prevalent (Class 3 or 4 locations) as well as requirements to prevent the accumulation of gas in confined spaces (*see, e.g.*, §§ 192.167(c)(2), 192.353(c), 192.355(b)(2), and 192.361(e)(3)). But leaks on gas pipelines that are not associated with potential ignition of leaks also entail public safety risks. Leaks of toxic or corrosive gases from part 192-regulated pipeline facilities can have serious public safety consequences. And leaks of any type can degrade into catastrophic failures—sometimes referred to as the “leak-before-break” concept.¹³⁹ Additionally, the absence of baseline leak detection equipment technology requirements for conducting leakage surveys can also inhibit timely opportunities to identify, evaluate, and remediate leaks. The absence (in subparts M, O, and P) of repair criteria and mandatory repair schedules for all leaks compounds the

delays and methodological shortcomings in identifying leaks. And PHMSA’s limited reporting requirements for leaks from all types of gas pipeline facilities can complicate its ability to identify systemic pipeline integrity issues or support enforcement actions against specific operators. Lastly, the exemption of all gas gathering pipeline facilities from NPMS reporting requirements inhibits timely leak detection and introduces heightened vulnerability to a principal mechanism (excavation damage) for loss of pipeline integrity.

PHMSA further estimates that, due to those limitations in its regulatory regime, thousands of leaks persist across part 192-regulated gas pipelines. With respect to gas distribution pipelines, PHMSA annual report data between 2010 and 2021 yields roughly the same per-mile, nationwide averages of repairs of all leaks (0.225 leaks repaired/mile in 2010 and 0.230 in 2021) and repairs of hazardous leaks (0.089 in 2010 and 0.086 in 2021). PHMSA assumes that the average per-mile rate at which new leaks are created (controlled for material type) remains constant, suggesting either that operators may not be reporting to PHMSA a significant number of leak repairs on their gas distribution pipelines; operators are not discovering or repairing a significant number of leaks on their gas distribution pipelines; or existing regulatory requirements and operator repair practices have not yielded improvements in reducing the frequency of leak repairs (and perhaps have failed to yield improvements in leak identification) on gas distribution pipelines for nearly a decade. PHMSA incident report data for gas distribution pipelines shows that distribution system operators reported only 377 incident reports identified as leaks (rather than ruptures or mechanical punctures) during the entire period from 2010 through 2020. This represents a miniscule percentage of the 510,224 leak repairs reported on operators’ annual reports in 2020 alone, a figure which does not include leaks that are not scheduled for repair at all. Forty-five percent of these reported leaks were attributable to causes that progressed over time (*e.g.*, corrosion failure, equipment failure, and material failure), which may have been discovered earlier through more frequent leakage surveys, patrols, and repair practices. As described later in this section, evidence that leaks that are large in release volume or hazardous to public safety are not reliably detected or repaired is further supported by available state-

¹³⁹ *See, e.g.*, Wilkowski, “Leak-Before-Break, What Does It Really Mean?” 122 *Journal of Pressure Vessel Technology* 267 (Aug. 2000); Zhang, et al., “Paper: Preventive Leak Detection for High Pressure Gas Transmission Networks,” *AAAI 2017* (2017); *see also* GPTC Guide appendix G–192–11 table 3c, recommending that grade 3 leaks be re-evaluated within 15 months or during the next required leakage survey.

level information shows persistent backlogs of grade 3 leaks and research with advanced leak detection methods, which suggests that operators may not reliably detect releases with large volumes or that are hazardous to public safety.

Data from States employing the three-tiered GPTC Guide leak grading framework (discussed in section II.E.) for gas distribution pipeline facilities demonstrates that most leaks on distribution main and service pipelines that are identified by operators are not subject to PHMSA repair requirements as hazardous leaks, and can persist for extended periods before repair. By way of example, the 2020 Pipeline Safety Performance Measures Report from New York State reports that out of 19,683 leaks on main and service pipelines discovered by 11 natural gas local distribution companies in 2019, 7,403 (37.6%) were grade 1 leaks that approximate to “hazardous leaks” under PHMSA repair requirements in § 192.703(c), while an additional 5,468 (27.8%) were grade 2 leaks, and 5,768 (29.3%) were grade 3 leaks using New York State requirements similar to the GPTC Guide criteria.¹⁴⁰ New York State has adopted repair deadlines mirroring those in the GPTC Guide for grade 2 leaks (12 months or 6 months, depending on potential hazard, see 16 NYCRR 255.813–255.815). However, neither the GPTC Guide nor New York regulations (as of October 2022) require repair of grade 3 leaks, resulting in a backlog of almost 10,000 outstanding unrepaired leaks in 2020.¹⁴¹ Each of these unrepaired leaks will continue to release methane (or other gases) to atmosphere until remediated, and each could increase in size between patrols or leakage surveys. Minority populations and other disadvantaged communities often bear the brunt of unrepaired leaks on those gas distribution systems.¹⁴² The IM

regulations at subpart P have proven insufficient to prevent leaks, as all the gas distribution pipelines, including those in the New York data described above, had been subject to DIMP regulations.

The number of leaks from gas transmission pipelines are also significant. A review of PHMSA incident data yields that over 500 (roughly 40%) of the 1,300 incidents reported by gas transmission operators between 2010 and 2020 involved hazardous leaks.¹⁴³ PHMSA’s IM regulations at subpart O do not ensure that pipeline operators prevent such leaks. Of the over 500 leaks reported as incidents on gas transmission pipelines between 2010–2020, nearly a quarter of those incidents occurred on gas transmission pipelines subject to subpart O requirements. Further, incident reports on gas transmission pipelines show that many were either identified during leakage surveys or patrols or were attributed to causes that could have degraded over time. PHMSA therefore expects that more frequent patrols and leakage surveys and prompt remediation would result in earlier detection and potential avoidance of leak degradation that would lead to incidents.

Annual report data similarly suggests a large number of leaks on gas transmission pipelines and the potential value of enhanced leak detection and repair requirements for promptly identifying and remediating those leaks. In annual reports submitted between 2012–2021, operators of gas transmission pipelines reported repairing an average of 13,600 leaks repaired per year across the 302,000 miles of gas transmission pipelines nationwide. But part 191 requires annual reporting of only the number of leaks repaired—not all detected leaks (even hazardous leaks detected but not repaired). In addition, part 192 does not provide clear timelines for “prompt” repair of hazardous leaks, much less any timeline for other leaks. Even if unreported, non-hazardous leaks occurred on gas transmission pipelines at just a fraction of the average, per-mile rate of hazardous leak repairs noted in annual reports over the last decade, there would be a significant number of additional, unreported leaks on gas transmission pipelines each year. Those

unreported leaks would generally not be subject to prescribed repair timelines under existing PHMSA regulations. Although some of those leaks could be identified and corrected in a timely manner pursuant to PHMSA’s IM regulations at subpart O, the limited application of those requirements (only transmission pipelines in HCAs) and the significant discretion given to operators in designing and executing IM plans do not guarantee any such leaks would be identified and remediated promptly.

PHMSA similarly understands that its existing regulations tolerate the persistence of numerous leaks on part 192-regulated gas gathering pipelines. Data from incidents on Types A and B gas gathering pipelines across 2010–2020 yields an average, per-mile rate of incidents—83 incidents on 11,542 miles of pipeline (0.0072 incidents/mile)—nearly double that of gas transmission pipelines (0.00435 incidents/mile) over the same period. Further, leaks are a more frequent cause of incidents on Types A and B gas gathering pipelines than for gas transmission pipelines—operators attributed nearly 80% of the incidents reported on Types A and B gathering pipelines to leaks. And PHMSA understands from reviewing incident reports for Types A and B gathering pipelines that many of those incidents could have been avoided or mitigated by more timely detection and repair. Annual report data for Types A and B gathering pipelines tells a similar story. In 2020 annual reports, Types A and B gathering operators reported 1,574 hazardous leak repairs on 298,795 miles of onshore gas transmission pipelines (5.3 leaks per 1,000 miles) and 153 hazardous leak repairs on 11,542 miles of Type A and Type B regulated onshore gas gathering pipelines (13.3 leaks per 1,000 miles). If the number of hazardous leak repairs corresponds to the total number of hazardous leaks identified, Types A and B gathering pipelines would have an average, per-mile rate of hazardous leaks more than twice that of gas transmission pipelines. Similar to the discussion above regarding distribution and transmission lines, the annual report-derived values understate the total number of leaks on Types A and B gathering lines. Therefore, the total number of leaks on Types A and B gathering lines not subject to any meaningful Federal repair requirements is likely even higher.

Furthermore, the number and persistence of leaks on Type C pipelines are likely to be higher than on Types A and B gas gathering pipelines because Type C gathering pipelines have historically avoided any meaningful

¹⁴⁰ State of New York Department of Public Service, Case 21–G–0165, “2020 Pipeline Safety Performance Measures Report” (June 17, 2021), <https://www3.dps.ny.gov/W/PSCWeb.nsf/All/9DBA66C148A1310985257B2600750639?OpenDocument>. Note that New York leak classification requirements use the term “types” rather than “grades,” however they are conceptually identical.

¹⁴¹ State of New York Department of Public Service, Case 21–G–0165, “2020 Pipeline Safety Performance Measures Report” at Appendix K (June 17, 2021), <https://www3.dps.ny.gov/W/PSCWeb.nsf/All/9DBA66C148A1310985257B2600750639?OpenDocument>.

¹⁴² Luna et al., “An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA,” 162 *Energy Policy* 112778 (2022). This study of the distribution of gas leaks reported to the Massachusetts Department of Public Utilities found consistently higher densities of unrepaired leaks in the homes of people of color, lower income persons, renters, adults with lower

levels of education, and limited English-speaking households. These same groups were more likely to experience slower repair times and significantly older unrepaired leaks.

¹⁴³ This calculation is based on a review of gas transmission pipeline incident reports, excluding incidents attributed to other causes such as “mechanical puncture,” “rupture” or “other.”

State or Federal reporting or design requirements.¹⁴⁴

The number and persistence of leaks on gas distribution, transmission, and gathering pipelines tolerated by PHMSA regulations entail considerable risks to public safety.¹⁴⁵ Each of those leaks discussed above that were or became incidents reported pursuant to part 191 involved significant public safety consequences: specifically, one or more of death, personal injury necessitating in-patient hospitalization, property damage of \$122,000 or more (excluding the value of the gas itself), or 3 MMCF or more gas lost. Similarly, each of the hazardous leaks observed on gas pipelines under existing PHMSA regulations are a hazard with respect to public safety. Since leaks in pressurized systems can over time degrade into catastrophic failures, even those leaks that have not yet been reported as incidents or otherwise designated as hazardous in that they do not involve an existing or imminent risk of ignition can nevertheless give rise to such risk if not repaired.

Lastly, any leak from gas gathering pipelines entails unique public safety risks. Natural gas gathering pipelines are often located in the vicinity of socially vulnerable populations.¹⁴⁶ Additionally, unprocessed natural gas within gathering pipelines typically contains significant quantities of volatile organic compounds (VOCs) and hazardous air pollutants (HAPs) such as benzene (a known carcinogen). As discussed in further detail in the Preliminary RIA, VOCs and HAPs pose risks from long-term adverse health effects. VOC emissions are precursors to ozone, and to a lesser extent fine particulate matter (PM_{2.5}). Both ambient ozone and PM_{2.5} are associated with adverse health effects, including respiratory morbidity, such as asthma attacks, hospital and emergency department visits, lost school days, and premature respiratory mortality. HAPs contained in unprocessed natural gas includes several substances that are known or suspected carcinogens,

including but not limited to benzene, formaldehyde, toluene, xylenes, and ethylbenzene. Benzene and formaldehyde are known human carcinogens, and ethylbenzene has been identified as possibly carcinogenic in humans. Chronic (long-term) inhalation of benzene can result in several adverse noncancer health effects including arrested development of blood cells, anemia, leukopenia, thrombocytopenia, and aplastic anemia, and acute (short-term) exposure to benzene vapors has been reported to cause negative respiratory effects. Formaldehyde inhalation exposure also causes a range of noncancer health effects including irritation of the nose, eyes, and throat, and repeated exposures cause respiratory tract irritation, chronic bronchitis, and nasal epithelial lesions. There is evidence that formaldehyde may also increase the risk of asthma and chronic bronchitis in children. Inhalation of toluene, mixed xylenes, and ethylbenzene can have neurological, respiratory, and gastrointestinal effects, among others, with chronic exposure to toluene potentially leading to developmental effects such as central nervous system dysfunction, attention deficits, and other anomalies. Further, corrosives entrained in the unprocessed natural gas can accelerate corrosion in the vicinity of leaks, thereby increasing the risk of a catastrophic failure. Recent incident data on Types A and B gas gathering pipelines similarly underscores the unique risks to public safety posed by the exemption of any part 192-regulated gas gathering pipelines from PHMSA's NPMS reporting requirements. The average, per-mile rate of incidents due to excavation damage reported to PHMSA between 2010 and 2020 on Types A and B gathering pipelines was comparable to that on distribution pipelines (0.023 and 0.027 annual incidents per 1,000 miles, respectively); further, insufficient locating practices have been reported to PHMSA as a contributing factor in those incidents.

Aside from the public safety risks discussed above, leaks from gas distribution, transmission, and gathering pipelines are also a significant contributor to climate change. As discussed in section II.C.2 of this NPRM, current methane emissions data identifies leaks across line pipe alone on U.S. natural gas distribution, transmission, and gathering as a significant contributor (the GHGI estimates nearly 328.9 kt CH₄ in 2019) to U.S. methane emissions. But current methane emissions estimates could materially understate actual methane

emissions. GHGRP reporting requirements do not capture all gas pipeline mileage subject to PHMSA's regulations at parts 191 and 192, introducing uncertainty into whether national average methane emissions estimates derived from such reports may accurately be extrapolated to all PHMSA-regulated gas pipelines. Additionally, recent evidence from aerial surveys of a small (7,500 square kilometer) swath of the Permian basin¹⁴⁷ found leaks from natural gas gathering pipelines in the Permian basin to be a larger source of methane emissions than would be calculated using the national average in the GHGI.¹⁴⁸ A series of two-week aerial surveys conducted in the fall of 2019, summer of 2021, and fall of 2021 conducted for the Environmental Defense Fund (EDF)'s Permian Methane Analysis Project observed between 50 and 350 leaks attributed to gas gathering line pipe, of which roughly half are likely attributable to part 192-regulated gathering line pipe. PHMSA made this assessment by comparing the leak coordinates for gathering line pipe within the raw data of EDF's Permian Methane Analysis Project¹⁴⁹ to geospatial data for specific gathering pipelines downloaded from the Texas Railroad Commission (TRRC) website.¹⁵⁰ PHMSA then reviewed the TRRC's database of attributes of those gathering pipelines to determine diameter, using that metric to determine whether an observed leak was on a part-192 regulated gathering pipeline. The leaks identified in these aerial surveys, moreover, were not de minimis: the average leak rate observed by EDF was 273 kg CH₄/hour, correlating to roughly a metric ton of methane emitted to atmosphere every five days. Even this limited Permian Basin data could under-report the number and scale of leaks from methane emissions from gas gathering pipelines if projected

¹⁴⁷ The entire Permian basin covers approximately 86,000 square miles—more than 220,000 square kilometers.

¹⁴⁸ See Yu et al., "Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin," *Environ. Sci. Technol. Lett.* (Nov. 8, 2022) (Yu Study) ("The EF [(emissions factor)] derived from each of the four aerial surveys is more than an order of magnitude higher than the EPA's published values [for national average emissions]"). The emissions factors calculated from this study were also "4–13 times higher than the highest estimate derived from a published ground-based survey of gathering lines."

¹⁴⁹ See EDF, Permian Methane Analysis Project, <https://permianmap.org/> (last accessed July 20, 2022).

¹⁵⁰ <https://rrc.texas.gov/oil-and-gas/publications-and-notices/maps/> (last accessed July 25, 2022).

¹⁴⁴ See, e.g., PHMSA, Doc. No. PHMSA–2011–0023–0504, "Response to Petition for Reconsideration of the Gas Gathering Final Rule" at 3 (Apr. 1, 2022).

¹⁴⁵ PHMSA discusses in this section only direct public safety consequences of leaks; however (as explained in section II.D.3), leaks and other releases from gas pipelines can also have second-order public safety impacts resulting from climate change-induced natural force damage and equipment malfunction.

¹⁴⁶ Emanuel et al., "Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States," 5 *GeoHealth* (June 2021) (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

nationwide.¹⁵¹ Many of the gathering pipelines in the Permian basin are relatively new pipelines, while older gas gathering infrastructure in other production regions may leak at higher rates.

4. Regulatory Requirements Lag Commercially Available, Advanced Leak Detection Technologies

As explained above in section D.1, PHMSA regulations prescribe requirements for identifying leaks—leakage surveys and rights of way patrols—directed principally toward risks to public safety (from ignition of instantaneous, large-volume releases or accumulated gas) and not toward environmental harm that even small leaks can cause. Consistent with that historical approach, PHMSA regulations permit reliance on non-instrumented leak detection methods such as smell or visual surveys of gas transmission pipeline infrastructure and rights of way that are more appropriate for discovering ruptures or accumulated gas than smaller leaks. When leak detection equipment is required, PHMSA regulations specify neither particular leak detection technologies nor minimum performance standards for detection of gas concentration by leak detection equipment.

These shortcomings in PHMSA's regulatory regime allow operators to rely on inadequate or ineffective leak detection equipment and practices, rather than encouraging use of commercially available, advanced leak detection technologies and practices appropriate to different gases transported by gas pipeline facility subject to part 192. Many of these technologies and practices were discussed by PHMSA, industry and academic research organizations, and vendors within a virtual public meeting on advanced methane leak detection technology and practices hosted by PHMSA on May 5–6, 2021 (2021 Public Meeting).¹⁵² PHMSA staff also attended the Methane Detection Technology Workshop hosted by EPA on August 23–24, 2021 (2021 EPA Methane Detection

Technology Workshop).¹⁵³ 154 155 156 Presenters at these meetings described how innovations in equipment sensitivity, analytics, automation, and survey speed of leak detection services could increase the effectiveness and decrease the cost of detecting gas releases from oil and gas facilities.

At the 2021 Public Meeting, EDF presented a set of recommended elements for an advanced methane leak detection system, including (1) leak detection equipment with a parts-per-billion level of sensitivity¹⁵⁷ and the ability to capture other data for use in an algorithm to understand the size and location of leaks; (2) a defined deployment strategy or work practice to ensure that accurate data is being collected; and (3) comprehensive data collection on topics such as leak location, estimated leak flow rate or gas emission rate, a coverage map showing which areas were successfully surveyed and which areas were not, and a summary or cumulative loss estimate for the total area surveyed. AGA observed in their remarks at the 2021 Public Meeting and AGA et al.¹⁵⁸ in their written comments that most currently available leak detection technologies are focused on identifying indications of methane leaks in the air (*i.e.*, gas

concentration) rather than measuring the rate of leakage from a component. AGA et al. characterized methane concentration as a more appropriate metric for evaluating the public safety risks from explosion than for estimating the amount of methane going to atmosphere.

Several stakeholders at the 2021 Public Meeting emphasized the importance of flexibility in PHMSA's consideration of advanced leak detection standards, recommending that PHMSA assess the suite of leak detection technologies that are currently commercially available and introduce requirements that promote continued development of advanced technologies. EDF noted that it was essential that PHMSA set advanced methane leak detection standards that ensure an ongoing process for continuous technology improvement, recommending that PHMSA set a floor, not a ceiling, to create a space in Federal standards to push for the development of new ideas and improvements to technology over time for future incorporation. AGA et al. also suggested that applying prescriptive regulations could potentially limit the development of different technologies and innovations, stating that providing operators with flexibility can create opportunities and incentives for developing new technologies and innovations in leak detection and measurement. Similarly, the Pipeline Safety Trust (PST) stated that performance-based regulations for advanced leak detection (ALD) and methane reduction should use the capabilities of commercially available ALD technologies as a starting point, but that the ALD performance standards should change as commercially available technologies develop.

AGA et al. emphasized the value of leak data analysis in lieu of requirements that operators use specific advanced leak detection technologies. AGA et al. observed that studies across the gas industry supply chain show that a majority of emissions come from a small number of high-emitting leaks, and thus leak data analysis enables operators to make substantial inroads on reducing methane emission by identifying and prioritizing repair of the highest-emitting leaks. AGA et al. also urged PHMSA to consider the affordability of any new regulatory requirements and suggested that in some situations, a simpler, less costly technology or practice may achieve safety and environmental goals more successfully than a newer technology.

Notable commercially available, advanced leak detection technologies

¹⁵³ Recordings are available at the EPA meeting web page at: <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop#:~:text=Natural%20Gas%20Industry-.EPA%20Methane%20Detection%20Technology%20Workshop%20%2D%2D%20August%2023%20and%2024,oil%20and%20natural%20gas%20industry> (last accessed July 20, 2022).

¹⁵⁴ See “Attachment 1: Summary Report Methane Detection Technology Workshop” of “Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG)” at <https://www.regulations.gov/DocketIDNo.EPA-HQ-OAR-2021-0317-0166>.

¹⁵⁵ See “EPA's Methane Detection Technology Virtual Workshop. August 23–24, 2021. Audio”, “Transcripts”, and “Presentations” at <https://www.regulations.gov/DocketIDNo.EPA-HQ-OAR-2021-0317-0183,EPA-HQ-OAR-2021-0317-0181,andEPA-HQ-OAR-2021-0317-0182> respectively.

¹⁵⁶ See “Controlling Air Pollution from the Oil and Natural Gas industry. EPA Methane Detection Technology Workshop. August 23 and 24, 2021” <https://www.regulations.gov/DocketIDNo.EPA-HQ-OAR-2021-0317-0183>.

¹⁵⁷ EDF commented that parts-per-billion detection is important in this effort in light of the potential for hidden underground leaks, where only a small volume of gas may migrate through the pavement despite a significant leak buried under the street.

¹⁵⁸ The American Gas Association (AGA), API, American Public Gas Association, GPA Midstream Association (GPA), and Interstate Natural Gas Association of America submitted joint comments (Doc. No. PHMSA–2021–0039–0008) to the rulemaking docket after the 2021 Public Meeting. Throughout this NPRM, references to “AGA et al.” refer to those joint comments.

¹⁵¹ The Yu Study acknowledged that its data may also be underestimating emissions from gathering pipelines. The authors conservatively excluded any emissions sources in areas of co-located gathering and transmission pipelines where the source could not be definitively attributed, although the authors noted that it would be reasonable to assume at least some of those sources were from gathering pipelines. See Yu et al.

¹⁵² Recordings, transcripts, and slides from the 2021 Public Meeting are available at the meeting web page at <https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152>. A number of entities submitted written comments before and after the meeting that are available in the rulemaking docket at Doc. No. PHMSA–2021–0039.

and practices¹⁵⁹ are described briefly below.

Hand-Held Leak Detection Equipment

The most common method for instrumented leakage surveys (meaning a leakage survey performed using leak detection equipment) on natural gas pipelines consists of surveys along the pipeline right-of-way with handheld leak detection equipment. A surveyor typically uses a flame ionization detector (FID), infrared gas detector, optical gas imaging (OGI) device,) or other gas detector to sample gas above a buried pipeline, inside underground structures, and possibly in the soil. Handheld equipment is used to perform most leakage surveys, and any advanced leak detection solution that does not operate directly on or over the pipeline would still require confirmation of leak indications on the ground by operator personnel with handheld equipment. For aboveground or excavated leaks, gas detection instruments are often supplemented with a “soap test” that involves applying a soapy solution to the probable leak location. The location and size of the bubbles produced by escaping gas provides an indication of the exact location of the leak source and the relative size of the leak.

Handheld devices have been a focus of research and development (R&D) by PHMSA, equipment manufacturers, and operators. Recent innovations available on the market, including highly sensitive handheld equipment and laser-based detectors capable of detecting gas at a distance, have improved the effectiveness, efficiency, and safety of traditional walking surveys. A walking survey can be effective at detecting pipeline leaks, assuming that the location of the pipeline is known, adequate equipment is used, and survey personnel follow procedures that ensure the pipeline and potential migration paths are properly surveyed, and there may not be an alternative to walking surveys in some environments with poor equipment access. The performance of leak detection equipment and procedures may vary depending on weather and soil conditions or other environmental factors. The GPTC Guide includes

guidelines for performing leakage surveys.

Walking surveys, however, tend to be expensive and time-consuming because they require significant personnel resources to execute. Effectiveness of even advanced handheld leak detection technologies can be reduced by poor operator training, inadequate survey procedures, or use of poorly maintained or uncalibrated equipment.

Automobile-Based Leak Detection Equipment

Similar equipment used in walking surveys can be mounted on cars and trucks to allow efficient surveying of pipelines with adequate road access. The effectiveness of a mobile survey depends on weather conditions, the survey procedure, and whether the equipment has acceptable access to the location of the pipeline and possible gas migration paths. Some vendors have taken this concept a step further and combined highly sensitive gas detectors, some capable of detecting gas in the single ppb range, anemometers, GPS sensors, other sensors, and advanced analytics to enhance the capabilities of vehicle-based leakage surveys. Some advanced vehicle-based leak detection systems typically function by combining gas readings and wind indications to estimate the size and point of origin of a plume of gas as the vehicle drives through it. These leak indications (and gaps in the survey coverage) are then assessed by personnel with handheld equipment. For example, two studies measured gas concentrations in Boston, MA, and Washington, DC using Picarro mobile methane analyzer technology. In the 2004 survey of Washington, DC, the researchers surveyed 1500 miles of streets using a Picarro G2301 spectrometer device and the Picarro A0491 Mobile Plume Mapping Kit (A combination of the gas analyzer, a GPS device, and an anemometer). According to the equipment manufacturer, the G2301 device has sub 0.5 ppb precision over 5 seconds and an operating range of 0–20ppm when measuring methane,¹⁶⁰ though testing of the device during the Boston study found analyzer output to be within 2.7 ppb of known gas concentration during testing.¹⁶¹ In Washington, DC, out of 5,893 methane readings detected from the vehicle with a concentration greater than 2.5 ppm, the minimum concentration defined as

a leak indication in the study, 1,112 were measured at 5 ppm or greater.¹⁶² Additionally, the researchers inspected 19 of the larger emissions sources with a handheld combustible gas indicator and found gas concentration in nearby manholes exceeding 80% LEL (*i.e.*, a grade 1 hazardous leak) at 12 locations. Upon notifying the distribution operator, a subsequent reinspection found that hazardous conditions remained at nine leak locations. In Boston, 435 out of 3,356 methane indications were measured at 5 ppm or greater.¹⁶³ However, these measurements are based on “in-plume” measurements consistent with the operation of the Picarro mobile methane analyzer and similar vehicle-based systems rather than direct measurements within 5 inches of the leak location. The concentration of each potential leak indication measured in-plume is likely to be lower than the concentration measured in the immediate vicinity of the emissions source during a leak investigation.

Advanced vehicle-based leak detection systems were discussed extensively during the 2021 Public Meeting. A number of technology providers market automobile-based leak detection systems. EDF discussed their experience with advanced vehicle-based leak detection systems in partnership with Google and Pacific Gas and Electric (PG&E). According to EDF, research indicates that advanced mobile leak detection systems, vehicle-based platforms that rely on sensitive gas detectors, anemometers, GPS devices, other sensors, and analytics to locate the approximate source of gas plumes indicating possible leaks, can find more leaks in distribution systems compared to traditional survey methods. Also, according to EDF, one study found that surveys conducted by “traditional” methods in two cities failed to find 65 percent of the leaks that were discovered by advanced leak detection technologies, including some grade 1 leaks. EDF further commented that quantifying emissions can allow operators to prioritize replacement programs more effectively to the largest individual leaks.

On the other hand, AGA noted issues with excessive “false positives” from mobile survey technologies, where there are indications of leaks where none exist. AGA also noted that mobile survey technologies can fail to detect

¹⁵⁹ PHMSA acknowledges that much of the discussion of advanced leak detection technologies and practices in this section is presented in terms of advanced methane leak detection technologies for use in connection with natural gas pipeline facilities, rather than leak detection technologies and practices for other gases whose transportation within pipeline facilities is subject to part 192. However, many of the advanced leak detection technologies and practices for methane are comparable to the technologies and practices employed in connection with other gases.

¹⁶⁰ Picarro. G2301 Gas Concentration Analyzer Datasheet, https://www.picarro.com/g2301_gas_concentration_analyzer (last accessed Dec. 20, 2022).

¹⁶¹ Phillips et al., “Mapping Urban Pipeline Leaks: Methane Leaks Across Boston,” 173 *Environmental Pollution* at 1–4 (2013).

¹⁶² Jackson et al., “Natural Gas Pipeline Leaks Across Washington, DC,” 48 *Environmental Science & Technology* at 2051–2058 (2014).

¹⁶³ Phillips et al., “Mapping Urban Pipeline Leaks: Methane Leaks Across Boston,” 173 *Environmental Pollution* at 1–4 (2013).

indications of a leak when a leak does exist. False positives require confirmation by operator personnel, and therefore cut into the cost-effectiveness of such surveys. PHMSA, during the 2021 Public Meeting, noted that there are challenges with certain leak detection technologies depending on the area where the survey is being performed.¹⁶⁴ For instance, driving surveys might best be conducted in densely populated areas where pipelines follow roadways. However, in rural areas with gas transmission and gathering pipelines, it can be more effective to use aerial surveys or continuous monitoring technology because pipeline rights-of-ways may be difficult to traverse on the ground. There might also be issues for operators using laser-based and other line-of-sight equipment in some areas.

Aerial Sensors and Continuous Monitoring

Other areas of industry interest are aerial sensing platforms and continuous monitoring. Aerial sensing involves gas detection equipment mounted on fixed wing or rotary wing aircraft, unmanned aerial systems (UAS), or satellites. Many aerial sensing methods are similar in principle to those used in advanced vehicle-based leak detection systems, except that the sensor suite is mounted on an aircraft or UAS, instead of a car or truck. Other aerial platforms may use direct sampling, laser-based methane detectors, LIDAR, OGI, or other methods that detect methane gas concentrations along a pipeline right-of-way or at aboveground facilities.

Recent research and perspectives shared at the August 2021 EPA technology workshop described above illustrate the potential advantages of aerial survey technologies for certain oil and gas facilities. The primary advantage of aerial surveys is that the speed of an aircraft can allow more efficient or more frequent surveys of large areas. Depending on the configuration of the facility, aerial surveys are potentially highly cost-effective. For example, during a panel conversation on the first day of the 2021 EPA Methane Detection Technology Workshop, Triple Crown Resources reported cost-effective methane emissions reductions of up to 90% from upstream production facilities via aerial

surveys performed by Kairos Aerospace.¹⁶⁵ In addition to leak detection and repair procedures, the operator also made changes to its operations and maintenance procedures to address the minimization of releases from tanks and other equipment. In that same panel, another operator reported that aerial surveys were not cost-effective for all of their facilities, but that aerial surveys, especially those mounted on UAS, have the additional advantage of being able to maneuver around locations or facilities that may be difficult for operator personnel to safely access with traditional equipment.¹⁶⁶ On the second day of the 2021 EPA Methane Detection Technology Workshop, a representative of BPX Energy (British Petroleum's onshore U.S. production business) described the company's quarterly aerial survey program using fixed wing aircraft and UAS in the Permian Basin, which is designed to detect, image, quantify, and map methane sources with an emissions rate greater than 5.5 mcf/d.¹⁶⁷ BPX reported that the aerial surveys can cover over 100 square miles per day, although these surveys are susceptible to meteorological conditions. The advantages of aerial surveys are likely to be most significant on long-distance transmission lines that can be surveyed efficiently with fixed wing aircraft. Likewise, long-distance or dense gas gathering pipeline networks may also be cost-effective to survey by air.

In contrast, drawbacks and limitations of aerial and continuous monitoring are similar to those of motor vehicle-based systems. While aircraft can access facilities that may be difficult to access with ground-based vehicles, the speed and altitude required for operation of fixed wing aircraft and helicopters can reduce the reliability of detecting smaller releases since gas concentration decreases with distance from the source and increased speed decreases the likelihood that an accurate measurement will be taken as the vehicle intersects a gas plume.

Additionally, aerial surveys may not be cost-effective for some system configurations. Most research and application of aerial systems have been in the upstream sector on gas production, processing, and gathering systems.

PHMSA expects that use of UAS for aerial monitoring will grow as technology continues to advance, and the Federal Aviation Administration (FAA) continues its work to integrate UAS into the National Airspace System. On January 15, 2021, FAA published a final rule to permit the operation of UAS at night and over people under certain conditions.¹⁶⁸ FAA is currently considering recommendations from an Aviation Rulemaking Committee on a regulatory approach to support beyond visual line of sight operations in the National Airspace System.¹⁶⁹

Continuous monitoring can take many forms and is a fast-maturing area of development. The most straightforward means of providing continuous monitoring is with stationary gas detectors that are able to communicate with operator personnel or a control center. The most straightforward means of continuous monitoring is mounting stationary sensors such as gas samplers or laser-based detectors in the vicinity of a pipeline. A stationary gas sampler must be located near potential leak locations in order to detect leaks, laser-based systems must have potential leak sources or migration paths within the line of sight and effective range of the device, though some newer devices are capable of scanning. Continuous monitoring with such sensors can therefore be costly, since more devices are required versus using one device to perform a survey, however real time leak information is a significant advantage, especially for intermittent sources. For example, the BPX Energy presentation at the 2021 EPA Methane Detection Technology Workshop noted that the company's stationary sensors refresh every 15 minutes.¹⁷⁰ For this reason, continuous monitoring can be especially effective at aboveground facilities where probable fugitive emissions sources are known

¹⁶⁴ Similarly, GPA and API submitted joint comments (Doc. No. PHMSA-2021-0039-0004) following the 2021 Public Meeting stating that the differences between gas gathering pipelines and gas transmission and distribution pipelines should be considered in developing any new regulations, guidance documents, or enforcement policies related to leak detection and repair.

¹⁶⁵ Johnson, Forrest and Wlazlo, Andrew. "Airborne Methane Surveys Pay for Themselves: An Economic Case Study of Increased Revenue from Emissions Control" Triple Crown Resources. EPA Methane Detection Technology Workshop (August 23, 2021). <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop>. Day 1 at 2:32:15.

¹⁶⁶ Berrica, P.E., "Key Takeaways from Deploying Four Novel Methane Detection Technologies".

¹⁶⁷ Faye Gerard, Ph.D. "BPX, Methane Measurements." BP America. EPA Methane Detection Technology Workshop (August 24, 2021). <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop>. Day 2 at 2:39:10.

¹⁶⁸ FAA, "Operation of Small Unmanned Aircraft Systems Over People," 86 FR 4314 (Jan. 15, 2021).

¹⁶⁹ Unmanned Aircraft Systems Beyond Visual Line Of Sight Aviation Rulemaking Committee Final Report, March 2022, available at https://www.faa.gov/regulations_policies/rulemaking/systems/documents/media/UAS_BVLOS_ARC_FINAL_REPORT_03102022.pdf.

¹⁷⁰ Faye Gerard, Ph.D. "BPX, Methane Measurements." BP America. EPA Methane Detection Technology Workshop (August 24, 2021). <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop>. Day 2 at 2:48:248.

beforehand and at high-risk locations where real-time alarms can help ensure public safety from fire and explosion risk.

Vendors and operators have been experimenting with a number of methods such as pressure wave monitoring, acoustic monitoring, in-ditch sensing with fiber optic sensors, and other devices. At the May 2021 Public Meeting, Siemens Energy and ProFlex Technologies presented on a negative pressure wave sensing technology for detecting “spontaneous leaks” on gas transmission, gas gathering, and similar applications. In that technology, pressure sensors placed periodically along the pipeline can detect anomalous negative pressure waves that propagate from the location of a rupture. According to the technology provider, the system can detect, by timing the rupture indications on the upstream and downstream sensors, estimate the location of the rupture within 20–50 linear feet. The technology provider claims that the system can detect leaks between ½ inch to 2 inches in area within a few seconds, therefore is potentially a sensitive and reliable means of detecting pipeline ruptures, however the system may not be able to reliably detect smaller leaks.¹⁷¹

In-Residence Methane Detection Tools

Another emerging area of industry interest is in-home methane detection. While gas piping downstream from the outlet of a customer meter is not regulated under the Federal pipeline safety regulations, PHMSA encourages the adoption of in-home methane detectors by operators, States, and standards developing organizations. As a result of NTSB investigations into a series of gas-related incidents in a neighborhood in Dallas, Texas in late February of 2018,¹⁷² and an investigation into an apartment explosion in Silver Spring, MD,¹⁷³ the NTSB included in-home methane detection on its 2021–2022 NTSB Most Wanted List.¹⁷⁴ NTSB recommended that the International Code Council, the

National Fire Protection Association, and the Gas Technology Institute (GTI) cooperate to develop standards and incorporate provisions in applicable national codes to require methane detection systems for all types of residential occupancies with gas service. The NTSB recommended that, at a minimum, these requirements should cover the installation, maintenance, placement of the detectors, and testing requirements. The PST and other public safety advocacy groups have also called on operators to install this technology wherever possible to provide for better public and environmental safety, as this technology can provide an extra level of protection against dangerous leaks. At the 2021 Public Meeting, the PST stated that the increased usage of in-home methane detectors would be relatively inexpensive and have the potential to dramatically reduce injuries, property damage, and deaths resulting from leaks and explosions from gas distribution systems.

Integration of Advanced Technologies and Practices Within Advanced Leak Detection Programs

Each of the commercially available, advanced technologies described above have inherent limitations that make their use more or less appropriate for use in connection with different gases, pipeline facilities, operating environments, weather conditions, and other factors. And even state-of-the-art equipment can deliver poor results if the operator’s procedures or training are inadequate or if equipment malfunctions. For this reason, a number of speakers during the 2021 Public Meeting emphasized that ALDPs must consist of a portfolio of mutually reinforcing advanced leak detection technologies, practices, and policies, each providing defense-in-depth for the inherent or operational limitations of other program elements.

An incident that occurred on a gas distribution pipeline operated by Atmos Energy, in Dallas, Texas on February 23, 2018, that had been surveyed shortly before the incident illustrates this truism.¹⁷⁵ Prior the February 23 incident, two other gas-related fires occurred on the same block on February 21 and February 22. The NTSB concluded that it is likely that the three incidents are related, but fire department investigators and operator personnel failed to pinpoint the source

of the leak that led to the February 23 incident. Since the fire department and the operator had not identified the distribution pipeline as the cause of the first two fires, no incident was reported to PHMSA. Following the February 22 fire, Atmos performed a leakage survey and repaired high-priority leaks on the pipeline segment involved in the incident. Atmos Energy’s leakage surveys incorporated modern leak detection equipment such as FIDs, optical methane detectors, remote methane leak detectors (RMLD, a type of laser-based gas detector), and other devices. However, the manufacturer’s instructions for the RMLD devices used to perform the leakage survey noted that the device performs sub-optimally in wet conditions and is not to be used when sustained wind or gusts exceed 15 mph. Additionally, the operator’s combustible gas indicator could be damaged when saturated. Due to precipitation, wind, and wet soil conditions, the operator’s RMLD survey was ineffective and the operator’s barhole¹⁷⁶ procedures to measure gas concentrations in the soil could not be performed. As a result, the operator failed to detect leaking gas from a cracked main, resulting in a third, fatal explosion on February 23, 2018.

5. State-Level and Operator Leak Detection and Repair Requirements

PHMSA regulations, as explained in section II.D.1 above, require operators of part 192-regulated gas transmission and distribution pipelines and certain regulated gathering pipelines to repair hazardous leaks promptly—without providing meaningful guidance regarding which leaks are hazardous, or precisely when any leaks must be repaired. The limitations of regulatory initiatives undertaken by State authorities and voluntary efforts (including methane emissions reduction commitments and pertinent industry standards) by pipeline operators, moreover, underscore the need for robust Federal leak detection, grading, and repair requirements.

GPTC Guide

The GPTC is an ANSI-accredited committee (ANSI Z380, or the Committee) that was formed in the late 1960s under the American Society of Mechanical Engineers. The Committee operates under a consensus process and is technically based and independent. The Committee is composed of

¹⁷¹ ProFlex Technologies and Siemens. “Siemens Energy Spontaneous Leak Detection Service powered by ProFlex.” May 2021. <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1154>.

¹⁷² NTSB, Pipeline Accident Report 21–01, “Atmos Energy Corporation Natural Gas-Fueled Explosion; Dallas, Texas; February 23, 2018” (Jan. 12, 2021).

¹⁷³ NTSB, Pipeline Accident Report 19–01, “Building Explosion and Fire: Silver, Spring, Maryland; August 10, 2016” (Apr. 24, 2019).

¹⁷⁴ NTSB, “Improve Pipeline Leak Detection and Mitigation: 2021–2022 Most Wanted List of Transportation Improvements” (Apr. 6, 2021).

¹⁷⁵ NTSB, Pipeline Accident Report 21/01

“Pipeline Accident Report: Atmos Energy Corporation Natural Gas-Fueled Explosion; Dallas, Texas; February 23, 2018” (Jan. 12, 2021).

¹⁷⁶ A barhole is a small hole dug into the ground in order to measure the concentration of gas within the soil by taking a sample within the barhole with a probe.

approximately 100 members from all facets of the gas industry, including gas distribution, transmission, storage, and gathering operators and manufacturers of gas-related equipment. The Committee also has members from the regulatory community, including PHMSA, the National Transportation Safety Board (NTSB), and other Federal and State regulatory agencies. Approximately 40 of the Committee's members, including PHMSA, are voting members.

The Committee publishes the GPTC Guide as an implementation tool facilitating compliance by gas pipeline operators with PHMSA regulatory requirements.¹⁷⁷ The first edition of the GPTC Guide was published in 1970, around the same time the Federal Pipeline Safety Regulations were first promulgated. The GPTC Guide is under continuous review and may be updated when prompted by pending rulemakings, NTSB reports, and requests from stakeholders, including PHMSA, the National Association of Pipeline Safety Representatives (NAPSR), or members of the public. The Committee periodically reviews requests for updates and may create a task group, if necessary, to issue new or amended guidance of versions of the GPTC Guide. The current edition of the GPTC Guide is the 2022 edition (including Addendum 1), published in June 2022.

Like the Federal Pipeline Safety Regulations, the GPTC Guide's leak grading and repair criteria are focused primarily on public safety rather than environmental protection. While the GPTC Guide itself has not been incorporated by reference in the Federal Pipeline Safety Regulations, several States have adopted at least the tiered leak grading criteria of the GPTC Guide and associated repair requirements into their regulations governing gas pipelines,¹⁷⁸ and PHMSA has referenced it from time-to-time in its implementing guidance.¹⁷⁹

¹⁷⁷ GPTC Guide at 18 (“While the GPTC Guide is intended principally to guide operators of natural gas pipelines, it is a valuable reference for operators of other pipelines covered by Part 192”).

¹⁷⁸ See National Association of Pipeline Safety Representatives (NAPSR), *Compendium of State Pipeline Safety Requirements and Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations, Third Edition* (Feb. 2022) (Compendium). References to “NAPSR” or to pertinent State requirements in this NPRM will, unless otherwise noted, will be to information within the Compendium.

¹⁷⁹ See, e.g., PHMSA, “Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators” (2013) at 2 (directing larger distribution pipeline operators to refer to GPTC guidelines); PHMSA, Interpretation Response Letter No. PI-93-009 (February 11, 1993)

Additionally, some gas pipeline operators incorporate sections of the GPTC Guide into their operating and maintenance procedural manuals for detecting, investigating, and classifying leaks.

The GPTC Guide contains appendices that provide procedures that comply with part 192. The GPTC Guide also provides guidance for controlling methane leaks from natural gas pipeline leaks in Appendix G-192-11 For gas distribution pipelines, section 6.2 of the DIMP guidance in Appendix G-192-8 describes possible elements of an “effective leak management program” and references the criteria for grading leaks from Appendix G-192-11 and, for liquefied petroleum gas (LPG) systems, Appendix G-192-11A. Each section includes tables 3a, 3b, and 3c summarizing the grading criteria and recommended repair requirements. The grading criteria from GPTC Guide Appendix G-192-11 and Appendix G-192-11A are discussed below (hereafter, references to the GPTC Guide refer specifically to Appendix G-192-11 and 11A unless otherwise specified).

Section 5.5 of the GPTC Guide characterizes a grade 1 leak as a “leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.” This mirrors the definition of a “hazardous leak” at § 192.1001. This characterization omits consideration of potential hazard to the environment, and the phrase “existing or probable hazard” is not defined in any part of the GPTC Guide. However, Table 3a of the GPTC Guide provides the following examples of grade 1 leaks:

- (1) Any leak that, in the judgment of operating personnel at the scene, constitute an immediate hazard.
- (2) Escaping gas that is ignited.
- (3) Any indication of gas which has migrated into or under a building, or into a tunnel.
- (4) Any indication of gas which has migrated to at an outside wall of a building where gas would likely migrate or into a tunnel.

(recommending public stakeholder consult the GPTC Guide for further determination of instruments and techniques to be used in certain leak detection activities); see also PHMSA, Interpretation Response Letter No. PI-99-0105 (December 1, 1999) (stating that the GPTC Guide “is a document endorsed by us which contains information and some methods to assist the gas pipeline operator in complying with the regulations contained in 49 CFR part 192”).

(5) Any reading of 80% [of the lower explosive limit] LEL, or greater, in a confined space.¹⁸⁰

(6) Any reading of 80% LEL, or greater, in small substructures (other than gas-associated substructures) from which gas would likely migrate to the outside wall of a building.

(7) Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

Building on the § 192.703(c) requirement that hazardous leaks (*i.e.*, grade 1 leaks) be repaired promptly, the GPTC Guide further specifies that an operator must take immediate and continuous action to protect life and property until the conditions are no longer hazardous. Per the GPTC Guide, such continuous actions could include: implementing an emergency plan written in accordance with § 192.615; evacuating the premises; blocking off an area; re-routing traffic; eliminating ignition sources; and venting the area by removing manhole covers, bar-holing, or installing vent holes. The GPTC Guide also notes that, for grade 1 leaks, operators should stop the flow of gas by closing valves or by other means and notify appropriate police and fire departments.

A grade 2 leak is an intermediate risk classification in the GPTC Guide. The GPTC Guide characterizes a grade 2 leak as a “leak that is non-hazardous at the time of detection but that requires or justifies a scheduled repair based on probable future hazard.” Like the description of a grade 1 leak, the characterization of a grade 2 leak in the GPTC Guide does not address hazards to the environment and does not provide a definition for the term “probable future hazard,” although example criteria are provided in Table 3b of the GPTC Guide. For grade 2 leaks, these criteria include leaks that require action ahead of the ground freezing, or where changes in venting conditions would likely cause gas to migrate to the outside wall of a building. Grade 2 leaks could also include leaks with a reading of 40% of the LEL or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak; a reading of 100% LEL or greater anywhere under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a grade 1 leak; a reading between 20% and 80% of the LEL in a confined space or in a small substructure; any non-zero concentration reading on a pipeline

¹⁸⁰ The Lower Explosive Limit (LEL) is the lowest concentration of gas that will burn in air in the presence of an ignition source.

operating at 30% of SMYS or greater in a Class 3 or Class 4 location that does not qualify as a grade 1 leak; and finally, any leak that, in the judgment of the operating personnel at the scene, is of sufficient magnitude to justify or require a scheduled repair. These examples demonstrate that the grade 2 leak classification, like the grade 1 classification, focuses operators on hazards to persons and property, without consideration of impacts on our environment.

The GPTC Guide requires that, upon detecting a grade 2 leak, an operator should repair or clear the leak “within one calendar year but no later than 15 months from the date the leak was reported.” The GPTC Guide states that, in determining the repair priority for the leak, an operator should consider the extent of gas migration, the proximity of gas to buildings in sub-surface structures, and the soil conditions (including frost cap, moisture, or natural venting). Operators can take a range of actions in addressing grade 2 leaks under the GPTC Guide. Some grade 2 leaks that are evaluated by the criteria listed above may justify a scheduled repair within 5 working days, whereas others might justify repair within 30 days. The GPTC Guide suggests that operators should schedule some grade 2 leaks for repair on a “normal routine basis,” with periodic re-inspection as necessary. The GPTC Guide suggests that operators should reevaluate grade 2 leaks at least once every 6 months until they are cleared, establishing a frequency of reevaluation based on the location and magnitude of the leak.

The GPTC Guide characterizes a grade 3 leak as “a leak that is non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous.” The term “non-hazardous” is not itself defined, but comparison to the grade 1 and grade 2 descriptions indicates that the grade 3 classification is intended to be a catch-all classification for all leaks that do not constitute either grade 1 or grade 2 leaks, including those leaks that are hazardous to the environment without representing a potential risk to public safety. Based on the criteria in Table 3c, grade 3 leaks would include leaks where there is a reading of less than 80% LEL in a small gas-associated substructure, any reading under a street in areas without wall-to-wall paving where it is unlikely that gas could migrate to the outside wall of a building, and any reading of less than 20% LEL in a confined space. The GPTC Guide suggests that operators should reevaluate grade 3 leaks during their next scheduled survey, or within 15

months of the date the leak is reported, whichever comes first, and continue reevaluations until the leak is either regraded or is no longer leaking. The GPTC Guide does not require the repair of grade 3 leaks. In comments submitted following the 2021 Public Meeting, AGA et al. noted the limitations of the GPTC Guide leak grading system with respect to environmental safety in light of the GPTC Guide’s focus on repair and remediation of leaks that are hazardous to public safety only.

The GPTC Guide provides for regrading of existing leaks based on changes identified during subsequent evaluations. If an operator discovers, during a reevaluation, that a grade 2 or 3 leak has become worse following its initial detection and grading to the point where it would now be classified at a higher grade, an operator must upgrade the leak to its appropriate grade and take appropriate action in accordance with the new grade. The GPTC Guide also permits operators to downgrade leaks by making temporary repairs to make the leak less hazardous. For example, an operator may vent a grade 1 leak by drilling multiple barholes into the soil in the immediate vicinity of the leak or by leaving vault boxes open to the atmosphere before grading the leak. These techniques can ensure that a leak is not an immediate hazard to persons or property and justify downgrading the leak to a grade 2 leak.

As described in section II.D.1, existing regulations require repair of hazardous leaks. In practice, the term hazardous leak has corresponded to a grade 1 leak under the three-grade leak classification framework in the GPTC Guide; a grade 1 leak is the most urgent classification under this framework. Section 5.5 of appendix G–192–11 of the GPTC Guide characterizes a grade 1 leak as one that “represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.” However, PHMSA regulations do not currently require the repair of leaks other than hazardous leaks that would be classified as grade 2 or grade 3 based on the GPTC Guide. Regarding the replacement or remediation of pipelines known to leak, appendix G–192–18 of the GPTC Guide suggests operators consider replacement of cast iron pipe based on the maintenance and leak history and operational and environmental circumstances and provides guidance on factors and situations to consider.

State Leak Detection, Repair, and Reporting Requirements

State regulatory requirements impose a patchwork of obligations on pipeline operators with respect to leak detection and repair. Pertinent requirements vary from one State to the next and even within a single State based on the type (gathering, transmission, or distribution) of pipeline in question or the gas being transported. Many of those State requirements are (like PHMSA’s current regulations) directed toward addressing imminent public safety risks rather than the climate and potential future safety risks posed by gas pipeline leaks. And, according to NAPS data, only a minority of the States have leak detection and repair regulations that exceed the current minimum Federal regulations for any type of gas pipeline.¹⁸¹

A handful of States require more frequent leakage surveys than required by part 192. Many of those survey requirements apply to only certain types of pipelines, with more demanding requirements for distribution systems than for other types of gas pipelines (e.g., gathering, intrastate transmission lines). And those requirements typically are directed toward addressing public safety rather than environmental harms, targeting areas where gas is likely to accumulate, where there is a high safety hazard in the case of a gas explosion, or pipelines that are higher risk due to their pressure or material. For example, the California Public Utility Commission requires annual leakage surveys “in the vicinity of schools, hospitals and churches,” in addition to the requirements for business districts in § 192.723, and requires that gas transmission pipelines be surveyed using leak detection equipment at least twice each year. Maryland requires annual leakage surveys for service pipelines serving places of public assembly. South Carolina requires leakage surveys for cathodically unprotected distribution pipelines at least once every 12 months, rather than 3 years as specified in § 192.723. Certain States also require operators to conduct more frequent surveys based on the location of the pipeline; for example, if the pipeline delivers gas to high-occupancy buildings or buildings of public assembly such as theaters, hospitals, or schools, or if the pipeline is near bridges or other transportation infrastructure. Other States provide a definition of the term “business

¹⁸¹ Zanter, Mary. “Presentation of NAPS at 2021 Public Meeting” (May 5, 2021), <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1150>.

district” subject to more frequent leakage surveys in § 192.723 but not defined in part 192. While a small minority of States do have increased surveying of cast iron pipes under certain conditions, few States require operators to replace or remediate these or other types of leak-prone pipe materials.

A minority of States have more specific requirements for the use of leak detection equipment than contemplated by current PHMSA regulations. NAPSR’s Compendium identified three States with leak detection equipment requirements that are more demanding than PHMSA’s requirements. Those States’ requirements seem largely focused on methane leaks from natural gas pipelines rather than leaks from pipeline facilities transporting other gases. A handful of states specify allowable leak detection equipment, generally requiring the use of an FID or equivalent device. For example, Maryland regulations require the use of flame ionization, combustible gas indicator in a barhole, optical methane detector, or other method approved by the Maryland Public Service Commission. New Jersey adopted an energy-related master plan in their overall State-wide climate goals that specifically directs the State utility commission to establish a standard for the use of advanced leak detection technologies when performing leakage surveys. NAPSR data indicates, however, that a majority of States do not have any more demanding requirements than PHMSA for the leak detection equipment used by operators. NAPSR’s Compendium similarly indicates that few States have right-of-way patrol requirements for gas gathering or transmission pipelines more demanding than those in current PHMSA regulations.

Most States, moreover, do not have reporting requirements for leaks that are more demanding than those in current PHMSA regulations. NAPSR’s Compendium indicates only a handful of States require periodic submission of leak status reports for any type of pipeline to State regulators, with a few States having recently adopted more comprehensive leak reporting requirements to achieve methane emission reduction goals. For example, California has established a comprehensive reporting system for gas utilities to submit annual methane leak abatement reports and compile emission reduction plans.

Apart from leak detection requirements, NAPSR’s Compendium yields that a majority of States have neither adopted the GPTC Guide’s leak

grading and repair criteria, nor have regulatory requirements supplementing the requirements for leak grading or leak repair in part 192. A few States (such as Texas, Kentucky, Massachusetts, and New York) have adopted leak grading and repair standards similar to those in the GPTC Guide. But many more States reported to NAPSR that they automatically adopt PHMSA’s pipeline safety regulations for leak grading and repair into their regulations and do not otherwise introduce more stringent requirements. Some of those States noted that they assume some operators follow the guidance in the GPTC Guide on the grading and repair of leaks described in section II.D.8. Few States have specific requirements for replacement of gas pipelines known to leak based on material, design, or past operating and maintenance history; among those States, replacement initiatives generally focused on gas distribution pipelines rather than gas gathering or transmission pipelines.

Of that minority of States that have regulations exceeding the current requirements in part 192 for grading and repairing leaks, most indicated that they followed a grading system resembling the GPTC grading system, where they classify leaks as grade 1, grade 2, or grade 3 based on relative safety hazards. However, these States may not impose leak grading and repair requirements uniformly across each type (gathering, transmission, and distribution) of pipeline. Mandatory repair timelines also differed among those States—particularly with respect to grades 2 and 3 leaks.

With respect to grade 2 leaks, some States do not have specific requirements for monitoring and repair and defer to operator procedures. Other States noted they require operators to recheck these leaks on subsequent surveys, per an operator’s procedures. Some States have requirements for operators to reassess grade 2 leaks every 6 months, with a few States requiring additional (or monthly) surveys until the leaks are cleared. There is also a wide variety of State approaches to repair timelines for grade 2 leaks: the States largely require the repair of grade 2 leaks anywhere from 12 months to 24 months after the date of discovery, with a handful of States requiring more immediate repairs.

With respect to grade 3 leaks, monitoring requirements for grade 3 leaks also vary widely between those States with grade 3 leak grading and repair requirements, with some States requiring operators to monitor grade 3 leaks every 6 months, and other States requiring operators to monitor grade 3 leaks every 15 months. The States that

have requirements for repairing grade 3 leaks follow one of two paths: either the State requires that grade 3 leaks be repaired within a prescriptive timeframe, such as 24, 30, or 36 months after discovery, or the State requires operators to have only a defined maximum number of outstanding grade 3 leaks. Some States only require operators to repair grade 3 leaks if the leaks have a relatively high emission rate. The methods for identifying high-emitting grade 3 leaks vary by State. For example, Massachusetts defines an “environmentally significant” grade 3 leak as one with a “leak extent” (land area affected by gas migration) of 2,000 square feet or greater, or with a highest barhole reading of 50% or more gas in air and requires its repair within either 2 years or 12 months, depending on the extent of migration. Some States noted that they required operators to perform additional leakage surveys after repairs are completed.

Industry Methane Leak Detection and Repair Practices and Efforts

Pipeline operator leak detection and repair practices are similarly insufficient to meet the risks to the environment and public safety from leaks of methane and other gases from gas pipeline infrastructure. Operators employ a spectrum of approaches and technology in connection with leak detection and repair—most of which are focused on compliance with pertinent Federal and State regulations that themselves inadequately address the public safety and environmental risks arising from all leaks on gas transmission, distribution, and part 192-regulated gathering pipelines. Although recent voluntary industry approaches pertaining to leak detection and repair are welcome, those efforts generally exhibit shortcomings (including meager participation, limited application to different pipeline facilities, absence of meaningful leak reduction targets, or a lack of transparency, limited application to natural gas pipelines), underscoring the need for timely Federal regulatory intervention. Moreover, while progress has been made on efforts to replace or remediate any pipeline known to leak based on material (such as cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history, it remains an issue. For example, according to PHMSA annual reports, 18,314 miles of cast or wrought iron distribution mains and 6,518 service lines remained in operation at the end of 2021.

Individual operators’ leak detection and repair programs have historically

focused on ensuring compliance with pertinent Federal and State requirements that (as explained above) generally lack meaningful requirements for timely grading and repair of leaks other than “hazardous leaks.” For those leaks from gas transmission, regulated gathering, and distribution facilities that are not considered “hazardous” under current PHMSA regulations, some operators may incorporate the GPTC Guide leak identification, grading, and mitigation criteria within their inspection and maintenance procedures, using the “LEAKS” mnemonic as an aide to their personnel tasked with managing leak detection and remediation.¹⁸² However, not all operators incorporate the GPTC Guide within their inspection and maintenance procedures; similarly, operators who integrate the GPTC Guide in their procedures include revision/amendment to those procedures, or may not adopt those procedures across all types of gas pipelines on their system.

Individual operators employ a range of equipment and technologies, with some operators employing advanced technologies such as infrared technologies, FIDs, and laser gas detectors to satisfy pertinent leakage survey requirements. For example, during the 2021 Public Meeting, a representative from the Knoxville Utilities Board (KUB), a gas distribution pipeline operator and member of the American Public Gas Association (APGA), noted that it performs leakage surveys by using handheld laser leak detectors while walking pipelines or travelling rights-of-ways with a Segway. For its distribution mains, KUB stated that it assesses those pipelines using a mobile method employing a traditional laser detector mounted in a vehicle, driving at lower speeds, and surveying major roads at night. During leakage surveys, if KUB technicians find an indication of a leak, they pinpoint the leak’s specific location. If the leak can be fixed with a minor repair—through an adjustment, a tightening, or lubrication—the technicians will make the repair on-site. If the technicians find a grade 1 leak during a survey, KUB stated the technicians stay on-site and provide site safety until a repair crew can make the appropriate, immediate repairs. KUB stated that they repair any discovered grade 2 leaks within 90 days, and grade 3 leaks within 6 months, but they also noted in their presentation

during the 2021 Public Meeting that repair schedules can vary from operator to operator. Similarly, Kinder Morgan during the 2021 Public Meeting stated that it employed a variety of methods and technologies (foot patrols; aerial surveys by fixed-wing aircraft or helicopter; automobile-borne sensors when the right-of-way is accessible) to perform right-of-way patrols on its transmission lines. However, these practices are not universal; rather (as explained above), the 2021 Public Meeting underscored that many operators are only beginning to integrate advanced leak detection technologies throughout their systems.

So far, voluntary industry standards have not resulted in operators employing adequate leak detection and repair practices. The non-mandatory Appendix M to ASME B31.8S, “Gas Transmission and Distribution Piping Systems” contains leak grading and repair criteria similar to the contents of the GPTC Guide.¹⁸³ However, that standard—like the GPTC Guide—specifies neither technology nor performance requirements for operator leak detection programs, and it contains no repair schedule for grade 3 leaks. In addition, PHMSA also understands that not every gas pipeline operator incorporates ASME B31.8–2007 into their inspection and maintenance procedures.

Following the May 2021 Public Meeting, AGA et al. highlighted a handful of the voluntary industry initiatives to reduce methane emissions—including leaks from gas gathering, transmission, and distribution pipelines.¹⁸⁴ However, publicly available information regarding those efforts does not confirm that leaks on gas transmission, distribution, and regulated gathering are detected and repaired in a timely manner. Precisely which pipeline operators and which pipeline facilities are captured by each initiative is generally not clear, but participation is far from universal among operators and pipeline facilities that would be subject to the amendments to part 192 contemplated in this NPRM. And even in those initiatives for which there is publicly available, operator-specific information, the focus is less on pipeline leak detection and repair than on other

potential sources of methane emissions (e.g., blowdowns, excavation damages). For example, while the Methane Challenge Best Management Practice Commitment Option documentation describes compressor station equipment leaks, it does not address leak detection and repair on buried pipeline facilities other than recommended replacement of cast iron and bare steel distribution pipelines.¹⁸⁵ Indeed, a review of publicly available information on the initiatives identified by AGA et al. does not indicate discrete emissions reduction targets for different operators or types of pipeline facilities. Only a minority of the initiatives identified by industry trade groups publish *any* data on the methane emissions reductions achieved—and that data does not show which specific operators are achieving their performance targets. Publicly available information does not demonstrate that these voluntary initiatives have led to reductions in emissions of methane and other gases.

6. Damage Prevention

Reducing excavation damage to pipelines has historically been a focus of PHMSA’s efforts in controlling public safety risks from gas pipelines—but is also an important component of mitigating harmful GHG emissions. Excavation damage creates a safety hazard for the public, the excavator, and the affected pipeline facility operator, and can lead to significant emissions going unnoticed or ignored if not posing an imminent public safety hazard. According to PHMSA data presented by AGA representatives at the 2021 Public Meeting, excavation damage in 2020 alone resulted in the loss of 245,000 MCF of gas from gas distribution pipelines—equivalent to the amount of emissions produced by 34 million miles driven by a vehicle or 50 million pounds of coal burned.¹⁸⁶ PHMSA incident reports have identified incidents caused by excavation damage that was not discovered for some time, or where no excavation work was ever reported.

Nevertheless, some State excavation damage prevention programs may not adequately address these risks. PHMSA has taken steps in recent years to establish and improve comprehensive implementation of State programs

¹⁸² The “LEAKS” management system mnemonic consists of Locating the leak, Evaluating its severity, Acting appropriately to mitigate the leak, Keeping records, and Self-assessing to determine if additional actions are necessary to keep the pipeline system safe.

¹⁸³ ASME, B31.8–2007, *Gas Transmission and Distribution Piping Systems*, 2007 Edition (2008) (ASME B31.8–2007). PHMSA regulations incorporate by reference elements of ASME B31.8–2007 in connection with yield strength testing procedure (§ 192.619(a)(1)(i)) or the alternative MAOP requirements (§ 192.620)—but not non-mandatory appendix M.

¹⁸⁴ AGA et al. at Appendix A.

¹⁸⁵ See EPA, “Methane Challenge Program BMP Commitment Option Technical Document” at 10 and 24–28 (May 2022), https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf (last accessed December 18, 2022).

¹⁸⁶ Sames, “Presentation of AGA at 2021 Public Meeting” at slide 7 (May 5, 2021), <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1139>.

designed to prevent damage to underground pipeline facilities. First, PHMSA published a final rule in 2015 establishing procedures at 49 CFR part 198 for evaluating State excavation damage prevention law enforcement programs and enforcing minimum Federal damage prevention standards in States where damage prevention law enforcement is deemed inadequate or does not exist.¹⁸⁷ PHMSA audited State damage prevention programs for adequacy under those new procedures in 2016, determining that 27 States had inadequate damage prevention enforcement programs. Second, PHMSA provides States with damage prevention grants to establish and improve comprehensive State damage prevention programs. Third, PHMSA's maintenance of the NPMS database gives pipeline operators, emergency response personnel and State and Federal regulatory authorities, as well as (to a lesser extent, given restrictions on data access) members of the public, data on location and other material characteristics of gas transmission pipelines, thereby reinforcing Federal and State damage prevention initiatives.

But even in States with robust damage prevention programs, limited information on buried gas pipelines can hamstring efforts to reduce excavation damage and marshal emergency response to any resulting incidents. This is particularly true for gas gathering pipelines. Despite recently expanded requirements that operators of certain gas gathering pipelines maintain sufficient damage prevention programs under § 192.614, PHMSA regulations do not currently require operators of gas gathering pipelines to submit geospatial location data into NPMS. This regulatory gap means that State and Federal regulatory authorities (and even some operators) may have limited understanding of the location of those pipelines, thereby inhibiting damage prevention efforts as well as emergency response in the event of an excavation incident.

E. The Limits of PHMSA Regulation and State and Operator Initiatives in Reducing Intentional Methane Releases From Gas Pipeline Facilities

In section 114 of the PIPES Act of 2020, Congress introduced requirements for operators of gas pipeline facilities to update their inspection and maintenance procedure to provide for the minimization of *all* releases of natural gas from their facilities—

including *intentional*, vented emissions—in recognition of the significant environmental harm from those emissions. As described in section II.C, equipment venting, blowdowns, and other vented emissions of methane account for a large portion of the total methane emissions from U.S. natural gas pipeline facilities—particularly natural gas transmission pipelines. However, despite the significant environmental impact of those emissions, PHMSA and State pipeline safety regulations have largely avoided explicit restrictions on vented emissions. Moreover, the absence of robust reporting requirements for those emissions under part 191 inhibits PHMSA's ability to identify systemic issues.

Part 191 does not require any reporting on intentional releases of methane or other gases (regardless of the total volume of gas emitted) unless a release causes death, hospitalization, or significant property damage. Similarly, part 192 and part 193 regulations do not require an operator to minimize intentional releases unless they could give rise to a public safety hazard.¹⁸⁸ These regulatory gaps could permit situations such as pressure relief devices being configured to establish overly-conservative actuation setpoints—resulting in avoidable emissions being released because those pressure relief devices vent methane more frequently than necessary to maintain system pressure within safe operating bands. Incident reports and National Response Center (NRC) reports submitted to PHMSA for pressure relief device malfunctions provide a sense of the magnitude of potential emissions from improperly configured pressure relief devices: each incident can result in the release of millions of cubic feet of methane.

Similar to voluntary leak detection and repair efforts, voluntary industry efforts to reduce emissions from blowdowns fall short in minimizing vented emissions. PHMSA is unaware of any industry-level, voluntary initiatives among operators of part 193 facilities to reduce vented emissions. And voluntary operator efforts among gas pipelines either parallel or directly invoke best practices recommended by the EPA's voluntary methane programs such as the

Methane Challenge Program and the Natural Gas STAR programs.¹⁸⁹ For the “Best Management Practices” option in the Methane Challenge Program, an operator can commit to cutting pipeline blowdown emissions by at least 50 percent by any of the following methods:¹⁹⁰

- Routing gas to a compressor or capture system for beneficial use;
- Routing gas to a flare;
- Routing gas to a low-pressure system by taking advantage of existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high and low-pressure systems; or
- Utilizing hot tapping, a procedure that makes a new pipeline connection while the pipeline remains in service, flowing natural gas under pressure, to avoid the need to blowdown gas.

The voluntary industry emissions reduction efforts above cannot boast universal participation, but they hint at the potential for significant reductions in vented emissions if applied across all gas pipeline facility operators. In 2019 alone, a mere 8 participants in the EPA's Methane Challenge transmission pipeline blowdown mitigation program, operating 29 gas transmission pipeline facilities, reduced emissions by 1.9 million metric tons of CO₂ equivalent estimated by calculation or measurement in accordance with 40 CFR part 98, subpart W or, for non-subpart W facilities, an alternative method.¹⁹¹

III. Federal Efforts To Address Climate Change by Reducing Methane Emissions

The urgency of reducing methane emissions to stave off or avoid the worst

¹⁸⁹ EPA, “Voluntary Methane Programs for the Oil and Natural Gas Industry,” <https://www.epa.gov/natural-gas-star-program> (last accessed June 20, 2022). In 2018, members of the Interstate Natural Gas Association of America (INGAA) agreed to adopt voluntary commitments to minimize methane emissions from member transportation and storage assets, including a commitment to reduce emissions from blowdowns when repairs need to be made. The aforementioned EPA programs and two industry initiatives, the ONE Future Coalition and the Environmental Partnership, are featured prominently in the INGAA commitments. The full list of commitments is available on INGAA's website (<https://www.ingaa.org/File.aspx?id=38523&v=6553c6c8#&:text=As%20part%20of%20our%20ongoing,build%20a%20cleaner%20energy%20future>) (last accessed July 20, 2022).

¹⁹⁰ EPA, “Natural Gas STAR Methane Challenge Program BMP Commitment Option Technical Document” at 21 (May 2022).

¹⁹¹ EPA, “Methane Challenge Program Accomplishments,” <https://www.epa.gov/natural-gas-star-program/methane-challenge-program-accomplishments> (last accessed July 20, 2022).

¹⁸⁷ PHMSA, “Pipeline Safety: Pipeline Damage Prevention Programs—Final Rule,” 80 FR 43835 (July 23, 2015).

¹⁸⁸ See, e.g., §§ 192.169 and 192.617(a)(2) (requiring discharge piping for compressor station pressure relief devices and emergency shutdown systems vent to locations that would avoid public safety hazards) and 192.199(e) (requiring pressure relief and limiting devices have discharge stacks, vents, or outlet ports be located where gas can be discharged into the atmosphere without undue hazard).

effects of climate change, coupled with the inability of existing Federal, State, and industry efforts to rise to that challenge, have catalyzed responses by the Federal legislative and executive branches to reduce unintentional and vented methane releases from gas pipeline facilities. Those efforts, which are discussed below, inform the regulatory amendments proposed in this NPRM.

A. The PIPES Act of 2020

The PIPES Act of 2020, which was signed into law with broad bipartisan congressional and widespread industry and stakeholder support on December 27, 2020, directed a fundamental shift in PHMSA's regulation of gas pipeline facilities: environmental benefits would join public safety as a principal object of PHMSA regulation.¹⁹² Concerned in particular with the contribution of methane releases from natural gas pipelines to climate change,¹⁹³ Congress included within that legislation three sections that would be implemented by this NPRM: sections 113, 114, and 118.

Section 113 of the PIPES Act of 2020 states that the Secretary of Transportation shall issue regulations that require operators of gas transmission pipeline facilities, gas distribution pipeline facilities, and certain regulated gas gathering pipelines in Class 2, Class 3, and Class 4 locations to conduct leak detection and repair programs to meet the need for gas pipeline safety and to protect the environment. Such regulations must include minimum performance standards that reflect the capabilities of commercially available advanced leak detection technologies that are appropriate for the type of pipeline, the location of the pipeline, the pipeline's material of construction, and the product transported by the pipeline. The leak detection and repair programs must be able to identify, locate, and categorize all leaks that are hazardous to human safety or the environment or that have the potential to become explosive or otherwise hazardous to human safety.

¹⁹² See 49 U.S.C. 60102(b)(5).

¹⁹³ See, e.g., 166 Cong. Rec. H7305 (Dec. 21, 2020) (memorializing a statement by Rep. Pallone that "[t]his is a big win in the fight against climate change, along with the reauthorization of the Pipeline Safety Act, which reduces methane leaks."); "Press Release from Senate Commerce Committee Leaders Commending Passage of Pipeline Safety Legislation" (Dec. 22, 2020), <https://www.commerce.senate.gov/2020/12/committee-leaders-commend-passage-of-pipeline-safety-legislation> (quoting Sen. Cantwell as stating "This legislation also ensures that the latest technology will be used to detect and prevent costly methane leaks, which is especially important because methane leaks are a significant hazard and a major contributor to global warming.").

The regulations must require the use of advanced leak detection technologies and practices through continuous monitoring on or along the pipeline, through periodic surveys with handheld equipment, equipment mounted on mobile platforms, or other commercially available technology. The regulations also must identify any scenarios where operators may use leak detection practices that depend on human senses, and include a schedule for repairing or replacing each leaking pipe, except for a pipe with a leak so small that it poses no potential hazard. Congress also expressly precluded the Secretary from reducing the frequency of surveys or extending the duration of leak repair or remediation timelines as required by PHMSA regulations on the date of enactment of the PIPES Act of 2020. Section 113 does not alter the Secretary's statutory authority to regulate gathering lines. Congress directed PHMSA to issue regulations implementing section 113 no later than December 27, 2021.

Section 114 of the PIPES Act of 2020 adjusts the requirements for inspection and maintenance procedures. This self-executing provision of the statute requires that pipeline operators ensure their inspection and maintenance plans contribute to eliminating hazardous leaks of gases (not limited to natural gas) and minimizing releases of natural gas specifically from pipeline facilities; protect the environment; and address the replacement or remediation of pipelines (including cast-iron, bare-steel, unprotected steel, wrought-iron, and certain plastic pipelines) that are known to leak based on material, design, or past operating and maintenance history. Operators had one year from the date of the enactment of the PIPES Act of 2020 (*i.e.*, no later than December 27, 2021) to update their inspection and maintenance plans to address these self-executing requirements.¹⁹⁴

¹⁹⁴ Section 114 also requires the Government Accountability Office to conduct a study to evaluate the procedures used by PHMSA and States when evaluating operators' inspection and maintenance plans, and subsequently issue a report regarding the findings of the study and recommendations for how to further minimize releases of natural gas from pipeline facilities without compromising pipeline safety. Additionally, the Secretary is to, not later than 18 months after the enactment of the PIPES Act of 2020, submit to Congress a report discussing the best available technologies or practices to prevent or minimize the release of natural gas, without compromising pipeline safety, when making planned repairs, replacements, or maintenance to a pipeline facility; or when intentionally venting or releasing natural gas, including when blowing down pipelines. The report must also discuss whether pipeline facilities can be designed, without compromising pipeline

Lastly, section 118 of the PIPES Act of 2020 amended the criteria set forth at 49 U.S.C. 60102(b)(5) governing issuance of any new rulemakings to elevate consideration of environmental benefits on par with other (*e.g.*, public safety) anticipated benefits. That statutory amendment reinforced the environmental purpose of section 113 of the PIPES Act of 2020, as well as historical provisions (*e.g.*, 49 U.S.C. 60102(b)(1)(B)(ii) and (b)(2)(A)(3)) within the Federal Pipeline Safety Laws that authorize PHMSA to issue regulations acknowledging the environmental protection benefits from regulation of gas pipeline facilities.

Gas pipeline operators and related trade associations applauded the passage through the Senate and later enactment of the PIPES Act of 2020 as part of the Consolidated Appropriations Act of 2021 (Pub. L. 116–260). For example, API released a statement in support of the Senate's passage of the legislation (S.2999) that became the PIPES Act of 2020, stating that the "PIPES Act takes important steps to make pipelines safer for surrounding communities and the environment."¹⁹⁵ Following enactment, INGAA described the PIPES Act of 2020 as a "historic piece of legislation" that "enhances pipeline safety, embraces the latest technologies, and aids in the further reduction of methane emissions."¹⁹⁶ At the 2021 Public Meeting, AGA et al. expressed support for the PIPES Act of 2020 and initiatives that protect the public and the environment, noting that their members have committed to a range of initiatives to reduce methane emissions to achieve goals for addressing climate change.¹⁹⁷

B. Administration Efforts Confronting the Climate Crisis

The U.S. Federal Government is taking aggressive action in response to climate change. During his first week in

safety, to mitigate the need to intentionally vent natural gas.

¹⁹⁵ API, Press Release, "API Statement of Senate Passage of PIPES Act (Aug. 6, 2020), <https://www.api.org/news-policy-and-issues/news/2020/08/06/api-statement-on-senate-passage-of-pipes-act>.

¹⁹⁶ INGAA, Press Release, "INGAA Hails Passage of Historic Pipeline Safety Reauthorization Bill in 2021 Omnibus Package" (Dec. 21, 2020), <https://www.ingaa.org/News/PressReleases/38353.aspx> (quoting President and CEO of INGAA, Amy Andryszak, praising Congress's direction to PHMSA to update its regulations "to reflect the latest technologies and practices [to] . . . both enhance safety and benefit the environment").

¹⁹⁷ Sames, Cristina. Pipeline Leak Detection, Leak Repair, and Methane Emissions. AGA. May 5, 2021. Briefing materials, recordings, and transcripts of the 2021 Public Meeting are available on the web page for the meeting at <https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152>.

office, President Biden established the National Climate Task Force, assembling leaders from across Federal agencies—including the Secretary of Transportation—to enable a whole-of-government approach to combatting the climate crisis.¹⁹⁸ Essential in those efforts are a spectrum of regulatory actions being undertaken across the U.S. Federal Government to reduce methane emissions described in the U.S. Methane Emissions Reduction Action Plan published in November 2021.¹⁹⁹ Parallel proposals by EPA and PHMSA to reduce methane emissions from natural gas infrastructure occupy a critical role in the Administration's whole-of-government strategy for tackling the climate crisis.

1. Pertinent Executive Orders

Several recent E.O.s direct PHMSA and other Federal agencies to undertake efforts to achieve substantial reductions of methane emissions from the oil and gas sector as soon as possible.

Executive Order 13990

On January 20, 2021, the President signed E.O. 13990, titled “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis”²⁰⁰ announced the Administration's re-commitment to environmental justice, science-based decision-making, protecting public health and the environment, and ensuring Federal agency actions account for the benefits of reducing climate pollution. Toward that end, E.O. 13990 directed all executive departments and agencies to immediately review and, as appropriate and consistent with applicable law, take action to address the promulgation of Federal regulations and other actions during previous years that conflict with these important national objectives, and to immediately commence work to confront the climate crisis.

¹⁹⁸ White House, “Fact Sheet: President Biden Takes Executive Actions to Tackle the Climate Crisis at Home and Abroad, Create Jobs, and Restore Scientific Integrity Across Federal Government” (Jan. 27, 2021), <https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/27/fact-sheet-president-biden-takes-executive-actions-to-tackle-the-climate-crisis-at-home-and-abroad-create-jobs-and-restore-scientific-integrity-across-federal-government/>.

¹⁹⁹ White House Office of Domestic Climate Policy, *U.S. Methane Emissions Reduction Action Plan* (Nov. 2021), <https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf>; White House Office of Domestic Climate Policy, *Delivering on the U.S. Methane Emissions Reduction Action Plan* (Nov. 2022), <https://www.whitehouse.gov/wp-content/uploads/2022/11/US-Methane-Emissions-Reduction-Action-Plan-Update.pdf>.

²⁰⁰ 86 FR 7037 (Jan 25, 2021).

Executive Order 14008

On January 27, 2021, the President signed E.O. 14008, titled “Tackling the Climate Crisis at Home and Abroad.”²⁰¹ E.O. 14008 puts “the climate crisis at the center of U.S. foreign and domestic policy,” with a focus on a multilateral approach to putting the world on a sustainable climate pathway and building resilience, both at home and abroad, against the impacts of climate change. Abroad, E.O. 14008 expresses the Administration's intent for the United States to exercise its leadership to meet the climate challenge by recommitting to the Paris Agreement and engaging in international climate summits and forums. Domestically, E.O. 14008 outlines a plan to focus on an all-in approach that considers environmental justice for all communities (especially those that have been underserved in the past), creates clean energy jobs, and builds modern and sustainable infrastructure.

2. Renewal of U.S. Commitments to International Efforts To Address Climate Change

Consistent with the instruction in E.O. 13990, the President returned the United States into the Paris Agreement on January 20, 2021.²⁰² The Paris Agreement is an agreement within the United Nations (UN) Framework Convention on Climate Change (UNFCCC) addressing climate change mitigation, adaptation, and finance, that was drafted throughout 2015 and was signed in 2016. The Paris Agreement was forged to help the world avoid catastrophic planetary warming and to build resilience around the world to the impacts from climate change that are occurring, with a long-term goal of keeping the rise in global average temperature to below 3.6 degrees Fahrenheit by reducing emissions of GHGs. To achieve these goals, article 4 of the Paris Agreement requires each party to prepare and maintain a “nationally determined contribution” of emissions reduction or mitigation targets once every 5 years. As of October 2022, 194 members of the UNFCCC are parties to the agreement; the United States had withdrawn from the agreement in 2020.

Pursuant to section 102(e) of E.O. 14008, the United States also submitted a new Nationally Determined Contribution (NDC), on April 4, 2021,

²⁰¹ 86 FR 7619 (Feb 1, 2021).

²⁰² <https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement>, <https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement>.

after rejoining the Paris Agreement.²⁰³ In the NDC, the Administration announced an ambitious “economy-wide target of reducing net greenhouse gas emissions by 50–52 percent below 2005 levels in 2030.” The NDC includes a specific commitment to address methane emissions by, among other efforts, “plugging leaks from wells and mains and across the natural gas distribution infrastructure.”²⁰⁴ The NDC notes that the United States aims to achieve these targets with a whole-of-government approach at the Federal level and ambitious innovation from State, local, and tribal governments, and private investment.

The United States further reinforced its commitment to reducing methane emissions by joining the European Union and several other countries in committing to the Global Methane Pledge ahead of the 26th global climate summit (the 26th Conference of the Parties, or COP26).²⁰⁵ In its joint statement with the European Union, the Biden-Harris Administration committed to direct the U.S. EPA and PHMSA to “reduce methane leakage from pipelines and related facilities,”²⁰⁶ and announced that more than 100 countries had joined the Global Methane Pledge and a commitment to reduce the world's methane emissions 30% from 2020 levels by 2030.²⁰⁷ The Administration has since released a U.S. Methane Emissions Reduction Action Plan detailing its comprehensive whole-of-government plan to reduce methane emissions through a combination of regulatory actions, financial incentives, increased transparency and data disclosure, and public and private

²⁰³ UNFCCC, Nationally Determined Contribution Registry (Interim), “The United States of America Nationally Determined Contribution” (April 4, 2021).

²⁰⁴ UNFCCC, Nationally Determined Contribution Registry (Interim), “The United States of America Nationally Determined Contribution” at 5 (April 4, 2021).

²⁰⁵ “Joint U.S.-EU Statement on the Global Methane Pledge” (Oct. 11, 2021), <https://www.state.gov/joint-u-s-eu-statement-on-the-global-methane-pledge/>; <https://www.state.gov/joint-u-s-eu-statement-on-the-global-methane-pledge/>.

²⁰⁶ White House, “Joint U.S.-E.U. Press Release on the Global Methane Pledge” (Sept. 18, 2021), <https://www.whitehouse.gov/briefing-room/statements-releases/2021/09/18/joint-us-eu-press-release-on-the-global-methane-pledge/>.

²⁰⁷ “Fact Sheet: President Biden Tackles Methane Emissions, Spurs Innovations, and Supports Sustainable Agriculture to Build a Clean Energy Economy and Create Jobs” (Nov. 2, 2021), <https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/02/fact-sheet-president-biden-tackles-methane-emissions-spurs-innovations-and-supports-sustainable-agriculture-to-build-a-clean-energy-economy-and-create-jobs/>.

partnerships.²⁰⁸ The Administration continues to lead nations around the globe in methane reduction efforts, including by reconvening the Major Economies Forum on Energy and Climate (MEF) on multiple occasions. The President reconvened the MEF most recently on June 17, 2022, to encourage participant countries to accelerate emissions reduction progress and provide a forum for participants to share the results of their Global Methane Pledge efforts.²⁰⁹ The regulatory requirements proposed in this NPRM would help align the United States with ongoing efforts from international partners to enhance methane mitigation requirements for gas pipeline infrastructure.²¹⁰

3. EPA's Proposed New Source Performance Standards and Emissions Guidelines for the Oil and Natural Gas Industry

On November 15, 2021, the EPA proposed new source performance standards and emission guidelines for crude oil and natural gas facilities.²¹¹ This action was in response to the January 20, 2021, Executive Order titled "Protecting Public Health and the

Environment and Restoring Science to Tackle the Climate Crisis." The 2021 action proposed to update VOC and methane²¹² standards on the books for new sources (located at 40 CFR part 60, subparts OOOO and OOOOa),²¹³ add new standards for new sources (which would be located at 40 CFR part 60, subpart OOOOb), and establish the first nationwide Emission Guidelines for states to regulate methane emissions from existing sources (which would be located at 40 CFR part 60, subpart OOOOc).²¹⁴ On December 6, 2022, in a supplemental proposal, EPA proposed further updates to its November 2021 proposal.²¹⁵ The proposed standards are developed based on the EPA's determination of the "best system of emissions reduction" (BSER) under section 111 of the Clean Air Act. The EPA's proposed emission standards, including emissions monitoring, repair, and maintenance requirements, would apply to numerous types of facilities (including pneumatic controllers and pumps, storage vessels, and sweetening units amongst others) across a defined source category.²¹⁶ Among the gas pipeline facilities within the scope of EPA's 40 CFR part 60 regulatory scheme are compressor stations on gas transmission pipelines and boosting stations on gas gathering pipelines.

C. PHMSA Implementation of the PIPES Act of 2020

PHMSA's efforts to implement requirements from the PIPES Act of 2020 efforts dovetail with policy goals of the Biden-Harris Administration described above. This proposed rulemaking in particular is a key part of PHMSA's efforts to address these policy priorities and is referenced in the White

House "U.S. Methane Emissions Reduction Action Plan."²¹⁷

1. PHMSA's May 2021 Public Meeting

PHMSA held a public meeting on May 5–6, 2021, (2021 Public Meeting) to provide stakeholder groups and members of the public an opportunity to share perspectives on improving gas pipeline methane leak detection and repair programs consistent with sections 113 and 114 of the PIPES Act of 2020. The agenda for the meeting included examining the sources of methane emissions from gas pipeline systems, the current regulatory requirements for managing fugitive and vented emissions, current leak detection and repair practices of the industry, and the use of advanced technologies and practices to reduce methane emissions from gas pipeline systems.

Stakeholders were invited to submit written comments in connection with the 2021 Public Meeting. PHMSA received 7 comments from individual pipeline operators, leak detection technology service providers, public safety groups, and industry trade organizations, as summarized below. The meeting itself included presentations and panel discussions from representatives from PHMSA, EPA, NAPS, EDF, PST, the United Association of Plumbers and Pipefitters, GPTC, AGA, American Public Gas Association, INGAA, GPA, Pipeline Regulatory Consultants, Gas Technology Institute, the Methane Emissions Technology Evaluation Center (METEC) at Colorado State University, QuakeWrap Inc., Bridger Photonics, Safetylics, ProFlex Technologies, ABB, the Federal Energy Regulatory Commission, and the National Association of Regulatory Utility Commissioners. Presentations, recordings, and transcripts from the meeting are available on PHMSA's public meeting web page.²¹⁸ Certain comments made before, during, and after the meeting have been summarized and discussed throughout this NPRM.

2. June 2021 Advisory Bulletin

PHMSA published an advisory bulletin on June 10, 2021, calling operators' attention to the self-executing requirements of section 114 of the PIPES Act of 2020.²¹⁹ The bulletin advised

²⁰⁸ White House Office of Domestic Climate Policy, *U.S. Methane Emissions Reduction Action Plan* (Nov. 2021), <https://www.whitehouse.gov/wp-content/uploads/2021/11/US-Methane-Emissions-Reduction-Action-Plan-1.pdf>.

²⁰⁹ <https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/18/chairs-summary-of-the-major-economies-forum-on-energy-and-climate-held-by-president-joe-biden/>. At this meeting of the MEF, the United States and the EU announced a new Global Methane Pledge Energy Pathway which "aims to encourage all nations to capture the maximum potential of cost-effective methane mitigation in the oil and gas sector and to eliminate routine flaring as soon as possible, and no later than 2030."

²¹⁰ For example, the European Union in December 2021 proposed legislation that would require member states to impose requirements that, at a minimum: (1) call for use of leak detection technologies with a minimum sensitivity comparable to those proposed in this rulemaking; (2) require leaks of at least 500 ppm to be immediately repaired or replaced and leaks of less than 500 ppm to be repaired or replaced within at least 3 months; and (3) create a default prohibition on all venting of methane (subject to certain exceptions). See European Parliament, "EU Briefing—Fit for 55 Package: Reducing Methane Emissions in the Energy Sector" (Mar. 2022), [https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/729313/EPRS_BRI\(2022\)729313_EN.pdf](https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/729313/EPRS_BRI(2022)729313_EN.pdf). Similarly, Canada in September 2022 issued a national Methane Strategy outlining policy options for reducing methane emissions from natural gas pipeline infrastructure. See Env't. & Climate Change Canada, *Faster and Further: Canada's Methane Strategy* (Sept. 2022), https://publications.gc.ca/collections/collection_2022/eccc/En4-491-2022-eng.pdf.

²¹¹ EPA, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 86 FR 63110 (Nov. 15, 2021).

²¹² EPA regulates greenhouse gases expressed in the form of limitations on methane.

²¹³ 40 CFR part 60, subpart OOOO regulates VOC only. 40 CFR part 60, subpart OOOOa regulates both VOC and methane.

²¹⁴ The proposed Emission Guidelines would address methane only.

²¹⁵ EPA, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," 87 FR 74702 (Dec. 6, 2022) (EPA SNPRM).

²¹⁶ The EPA defines the Crude Oil and Natural Gas source category to mean (1) crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and (2) natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station. For purposes of EPA's proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the "city-gate".

²¹⁷ White House Office of Domestic Climate Policy, *U.S. Methane Emissions Reduction Action Plan* (Nov. 2021).

²¹⁸ <https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=152>.

²¹⁹ PHMSA, "Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline

operators of pipeline facilities to update their inspection and maintenance plans to address the elimination of hazardous leaks and minimize gas releases from their pipeline facilities, including intentional venting during normal operations. The bulletin also noted that, per the statutory mandate, operators must revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history. The advisory bulletin noted that the PIPES Act of 2020 requires pipeline facility operators to complete these updates by December 27, 2021.

3. February 2022 PHMSA Webinar Addressing Inspection of Operators' Plans To Eliminate Hazardous Leaks, Minimize Releases of Methane, and Remediate or Replace Leak-Prone Pipe

On February 17, 2022, PHMSA held an informational public webinar reviewing the requirements for pipeline operator inspection and maintenance plans introduced by section 114 of the PIPES Act of 2020.²²⁰ This webinar was informational, with attendees having the opportunity to submit written comments to the public meeting docket. More than 1,500 individuals registered for the public webinar, including representatives from the gas gathering, transmission, and distribution sectors. During the webinar, PHMSA discussed key elements of the new section 114 requirements and reviewed the applicable timelines for the actions required under section 114. PHMSA also discussed its planned approach to inspection of operators' programs and procedures to reduce methane emissions and replace or remediate leak-prone pipes.

IV. Summary of Proposals

A. Leakage Survey and Patrol Frequencies and Methodologies

Existing Federal regulations in subpart M of part 192 are focused primarily on avoiding risks to public safety posed by of instantaneous, large-volume releases or accumulated gas from gas pipelines, with less attention given to environmental harms from methane leaks to the atmosphere and releases of other flammable, toxic or corrosive gases. Part 192 imposes leakage survey and patrol periodicities based on the magnitude and probability

of those public safety risks (via the proxies of class location, business districts, and potential impact radius), with operators required to conduct leakage surveys only once per calendar year but with an interval between surveys not to exceed 15 months for most gas transmission pipelines, offshore gathering, distribution pipelines inside of business districts, and some onshore part-192 regulated gathering pipelines; distribution pipelines outside of business districts are obliged to conduct surveys only once every five years. Sections 192.706 and 192.723 outline requirements for leakage surveys (including periodicity) on gas transmission and gas distribution pipelines, respectively, and all offshore, Types A and B gas gathering and certain Type C gathering pipelines must follow the § 192.706 leakage survey requirements for gas transmission lines. Those existing prescribed periodicities are described in further detail below.

Current regulations do not specify what technologies or equipment must be used in the performance of leakage surveys, and most gas gathering and transmission pipelines are exempt from odorization requirements that could help identify leaks. Currently, leakage surveys on all distribution lines and certain unodorized gas transmission and gathering pipelines must be performed using "leak detection equipment," but this term is not currently defined in part 192. PHMSA has historically declined to establish technology or performance standards regarding leak detection equipment. Leakage surveys on transmission pipelines in Class 1 or Class 2 locations or Class 3 and Class 4 locations that are odorized can rely entirely on human senses such as smell or sight. This NPRM proposes to set more specific technical standards for leak detection equipment used for leakage surveys, and these are described in detail in section IV.B of this NPRM.

PHMSA regulations currently require only annual right-of-way patrols on most gas transmission, offshore gathering, and Type A-regulated onshore gathering lines. Patrols are visual surveys and do not require the use of any equipment. Sections 192.705 and 192.721 define right-of-way patrolling requirements for gas transmission, (as well as offshore and Type A gathering), and distribution pipelines, respectively. While offshore and Type A gas gathering pipelines are subject to the same requirements as transmission lines, Types B and C gathering pipelines are not subject to any patrolling requirements. Patrols are typically reliant on human senses (vision, sound, or scent) and do not

require the use of leak detection equipment (although operators may incorporate leak detection equipment at their discretion). An operator may combine a patrol with a leakage survey, provided their procedures include both a visual survey of the right-of-way and a leakage survey with leak detection equipment. Patrols can detect unsafe conditions that may indicate a current or future leak or incident. For example, visual right of way patrols can identify construction activity that signifies a potential excavation damage threat, earth and water movement that may indicate a natural force damage threat, or population growth that may indicate change in class location, change in HCA or Moderate Consequence Area status, and higher potential consequences of an incident. Patrols can also detect certain leaks by odor, by detecting dead vegetation, or by other indicia (e.g., bubbles from an offshore, submerged pipeline). However, those approaches entail their own limitations; for example, reliance on smell would not be effective unless the gas contains odorants and vegetation surveys are only effective in certain soil and climate conditions (and completely ineffective in areas with no or sparse vegetation such as paved areas or deserts), and a noticeable impact on vegetation from a leak may lag substantially behind the leak's emergence.

The limitations of PHMSA's existing leakage survey and patrol regulations thus currently allow for extended periods of time during which leaks can degrade into catastrophic integrity failures, allow gas to build up and ignite, or emit a substantial amount of methane or other (flammable, toxic or corrosive) gases to the environment. For gas gathering lines conveying unprocessed natural gas, the risks to public safety and the environment from infrequent (or non-existent) leak survey requirements are particularly acute as any leaks releasing VOCs and HAPs, such as benzene, and corrosive materials entrained with the unprocessed natural gas can expedite degradation of pipeline integrity. And leaks of toxic or corrosive gases from other gas pipeline facilities can adversely affect environmental resources. The environmental impacts of gas pipeline leaks and the estimated environmental and public safety benefits of the requirements proposed herein are discussed in further detail in section 5 of the Preliminary RIA for this NPRM, available in the rulemaking docket. Further, the widespread use of human senses in leakage surveys is a missed opportunity to leverage existing

Facilities," 86 FR 31002 (June 10, 2021) (ADB-2021-01).

²²⁰ PHMSA's presentation during this webinar and a recording of the webinar meeting are available on PHMSA's public meeting web page at <https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=159>.

commercially available leak detection technology to protect against these risks to public safety and the environment by ensuring that leaks are identified and addressed in a timely manner. In addition to the public safety and human health risks of undetected methane leaks, long intervals between surveys also result in increased emissions of methane or other flammable and toxic gases. For example, in a presentation on the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model at the 2021 EPA Methane Detection Technology Workshop, modeling based on controlled tests and field evaluations demonstrated that at a given detection threshold, survey frequency is directly proportional to fugitive emissions reductions.²²¹ While the modeling shows decreasing emissions abatement returns to increasing survey frequency, large drop-offs begin to appear only after semiannual OGI surveys.

PHMSA therefore proposes to strengthen minimum leakage survey frequencies for gas transmission and gathering pipelines located in HCAs, aboveground offshore gas transmission and gathering pipelines, distribution pipelines outside of business districts, and distribution pipelines at a high risk of leakage. PHMSA also proposes to introduce patrolling requirements for Type B and Type C gathering pipelines and to increase the minimum patrolling frequency for all gas transmission, offshore gathering, and Type A regulated onshore gas gathering pipelines. Finally, while all operators may supplement instrumented leakage surveys with visual and other sensory survey techniques, PHMSA proposes to limit the exclusive use of human senses for leakage surveys to submerged offshore gas transmission and submerged offshore gas gathering pipelines and, subject to notification to and review by PHMSA, onshore gas transmission and regulated onshore gas gathering pipelines in Class 1 and Class 2 locations outside of HCAs. These amendments would ensure timely detection of leaks. The proposed changes to patrolling frequency would also increase the likelihood that conditions that could result in leaks, potentially fatal incidents, or damage that could result in shutdowns and maintenance-related releases of methane to the atmosphere are detected.

²²¹ Ravikumar, Arvind Ph.D. "FEAST-Based Evaluation of Methane Leak Detection and Repair Programs Using New Technologies." EPA Methane Detection Technology Workshop (August 24, 2021). <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop>. Day 2 at 1:33:50.

These proposals (and all other proposed amendments to parts 191 and 192) apply generally to pipeline transportation of any "gas," defined in §§ 191.3 and 192.3 as "natural gas, flammable gas, or gas which is toxic or corrosive." Although natural gas pipelines constitute the vast majority of part 192-regulated gas pipeline mileage today, the requirements for "gas" pipelines in parts 191 and 192 apply equally to pipelines transporting other gases, including over 1,500 miles of hydrogen gas pipelines in operation today.²²² Unless otherwise specified in the proposed amendments, the proposals in this NPRM apply the same requirements to hydrogen gas pipelines (and other gas pipelines) as to natural gas pipelines. PHMSA invites comment on whether, within a final rule in this proceeding, there would be value in adopting hydrogen gas pipeline-specific provisions (in lieu of or in addition to the provisions proposed herein). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA has not proposed in this NPRM to establish minimum leakage survey frequencies or leak detection equipment requirements for UNGSFs. This approach is consistent with current PHMSA regulations at § 192.12, which do not require UNGSFs perform periodic leakage surveys with leak detection equipment but rather oblige operators of UNGSFs to perform an integrity assessment of each reservoir, cavern, and well as often as necessary (but with a maximum interval between assessments that does not exceed 7 years). Additionally, consensus industry standards²²³ incorporated by reference in § 192.12 include recommendations and requirements for periodic UNGSF reservoir and wellsite inspection and monitoring. However, PHMSA invites comment on whether, within a final rule in this proceeding, there would be value in prescribing leakage survey frequency

²²² See PHMSA Interpretation Response Letter No. PI-92-030 (July 14, 1992) (noting PHMSA regulates hydrogen pipelines under part 192); PHMSA, "Presentation of Vincent Holohan for Workgroup#4: Hydrogen Network Components at December 2021 Meeting" at slide 11 (Dec. 1, 2021), <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1227>.

²²³ API Recommended Practice 1170, *Design and Operation of Solution-Mined Salt Caverns Used for Natural Gas Storage—First Edition* (July 2015); API Recommended Practice 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs—First Edition* (Sept. 2015).

and leak detection equipment requirements for UNGSFs in § 192.12. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

1. Distribution—§ 192.723

Section 192.723 outlines the current requirements for leakage surveys on gas distribution systems. Leakage surveys on distribution pipelines must be performed using leak detection equipment. Leakage surveys in business districts must be performed at least once each calendar year, with an interval between surveys not to exceed 15 months. On distribution pipelines outside of business districts that are not cathodically protected and where electrical surveys for corrosion are impractical (*i.e.*, bare steel, unprotected steel, and cast-iron systems), leakage surveys must be performed once every 3 calendar years, with an interval between surveys not to exceed 39 months. All other portions of a distribution system outside of business district must currently be surveyed once every 5 calendar years at intervals not exceeding 63 months. The term "business district" is not defined. PHMSA invites comment on potential criteria for defining the boundaries of a business district for potential inclusion within a final rule in this proceeding. Comments on these potential criteria are especially helpful if they address the potential safety and environmental benefits and potential costs of a proposed or alternative approach, including whether each proposal would be technically feasible, cost-effective, and practicable.

As described in section III.C, fugitive emissions from leaks represent the vast majority of total methane emissions from natural gas distribution systems. However, the current § 192.723 neither articulates minimum performance standards for leak detection equipment nor prescribes a particular technology to ensure that all leaks are identified during leakage surveys on distribution pipelines. PHMSA therefore proposes several regulatory amendments that would increase the frequency and effectiveness of leakage surveys to identify and repair leaks on gas distribution pipelines. First, PHMSA proposes that leakage surveys be incorporated within operator ALDPs meeting the minimum performance standards proposed in this NPRM and any detected leaks be graded and repaired consistent with the grading

framework in this NPRM (each discussed further in section IV.B). These proposals would better address the leading causes of methane emissions from gas distribution systems by ensuring that leaks are detected and repaired in a timely manner. Second, PHMSA proposes more frequent leakage surveys to promote earlier detection and repair of leaks, thereby improving the environment by reducing emissions from those leaks, and improving the likelihood that leaks are detected before they adversely impact public safety.

As described earlier, distribution leakage surveys are currently required once every 1, 3, or 5 calendar years, depending on the location and design of the pipeline. The 5-year maximum leakage survey interval allows even leaks hazardous to people or property that must be “repaired promptly” under current § 192.703 to remain undetected for up to 5 years, often placing the burden on the general public to detect and report potentially hazardous leaks via odor calls. In addition to the potential hazard to public safety and human health, an undetected leak will continue to emit methane to the environment until it is detected and repaired. PHMSA therefore proposes to eliminate the 5-year survey frequency tier by moving leakage surveys outside of business districts from at least once every 5 years into the next frequency category: at least once every 3 calendar years, with an interval between surveys not to exceed 39 months. Leakage surveys inside of business districts would still be required annually. This proposal would increase the frequency of leakage surveys on all distribution pipelines outside of business districts, consistent with the environmental and public safety risks of *any* leaks, while ensuring that operators continue to prioritize frequency of surveys inside of business districts where there is a higher risk to people and property. Combined with the repair requirements proposed in the new § 192.760, which proposes a maximum repair timeline of 24 months for grade 3 leaks, this ensures that operators repair all leaks prior to their next distribution leakage survey, preventing continued growth in the backlog of unrepaired leaks. Some States have adopted similar standards for leakage surveys outside of business districts, for example the Commonwealth of Massachusetts requires leakage surveys outside of “principal business districts” at least once every 24-months.²²⁴

Similarly, due to the increased environmental and safety risks of distribution mains and service lines that are either without cathodic protection, or known to leak based on material, design or past operating and maintenance history, PHMSA proposes to require that operators perform a leakage survey at least once each calendar year with the interval between surveys not to exceed 15 months, mirroring the high-priority survey frequency for unprotected pipelines and pipelines inside of business districts. Currently, such pipelines must be assessed at the lowest frequencies: once every 3 calendar years for cathodically unprotected distribution pipelines outside of business districts; once every 5 calendar years for all other distribution pipelines outside of business districts; or once every calendar year for all distribution pipelines within business districts. As with distribution pipelines outside of business districts, some States have also adopted enhanced leak survey requirements for leak-prone pipe. For example, the State of Kansas requires annual leakage surveys for cathodically unprotected steel mains and ductile iron mains in class 2, 3, or 4 locations.²²⁵ Consistent with section 114 of the PIPES Act of 2020, materials known to leak include cast iron, unprotected steel, wrought iron, and historic plastics with known issues. As described in the emissions discussion in section II.C, certain materials are responsible for a disproportionate amount of emissions from leaks, with distribution mains composed of such materials being particularly significant sources of emissions. PHMSA’s proposal seeks to increase the scrutiny of distribution systems outside of business districts at a high risk of leakage by decreasing survey intervals and targeting materials at a high risk of leakage. PHMSA’s proposal also contemplates that distribution pipeline operators would retain the option to establish more frequent leakage surveys than proposed herein within their operations and maintenance procedures or DIMP plans.

The following categories of distribution pipelines outside of business districts would be subject to the proposed annual survey requirement:

- Cathodically unprotected pipelines on which electrical surveys are impracticable, typically bare and unprotected distribution lines;
- Any distribution pipeline protected by a distributed anode system where the

cathodic protection survey under § 195.463 showed a deficient reading; and

- Pipelines known to leak based on the material (including, but not limited to, cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline.

PHMSA expects that, in determining whether a plastic pipe material is a “historic plastic with known issues” making it at high risk of leaks, operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues on plastic pipe made from particular materials; or manufactured at particular times or by particular companies, or fabricated and installed pursuant to particular processes. By way of illustration, PHMSA issues advisory bulletins cautioning operators regarding the susceptibility of certain historic plastics to systemic integrity issues. In 2007, in response to NTSB findings and data collection performed by the Plastic Pipe Database Committee (PPDC), PHMSA issued Advisory Bulletin ADB-07-01.²²⁶ That advisory bulletin called operators’ attention to cracking issues on pipe and components manufactured by Century Utility Products, Inc.; low-ductile inner wall “Aldyl A” piping manufactured by Dupont before 1973; polyethylene gas pipe made from PE 3306 resin; Delrin insert tap tees; and caps made of Celcon (polyactal) on Plexco service tees. Similarly, State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports, and NTSB findings can inform operator determinations whether historic plastic pipe is at a high risk of leakage. Industry efforts and resources are another resource for operators in determining whether historic plastic pipe is known to leak. For example, the PPDC publishes data submitted by program participants that incorporates information regarding investigations of materials of concern or potential concern.²²⁷ PHMSA expects that these and other authoritative resources—coupled with an operator’s own design expertise and operational and maintenance history—would be adequate for a reasonably prudent operator to determine whether the particular plastic pipe in its distribution systems is at a high risk of leakage.

²²⁶ “Pipeline Safety: Updated Notification of Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe-Advisory Bulletin ADB-07-01,” 72 FR 51301 (September 6, 2007).

²²⁷ APGA, “Plastic Pipe Database Collection Initiative,” <https://www.apga.org/programs/plasticpipe/data> (last accessed Dec. 20, 2022).

²²⁴ 220 Code of Massachusetts Regulations 101.06(21)(b).

²²⁵ Kansas Administrative Regulations 82-11-4(b)(34)(b)(2)(i).

PHMSA invites comment on the value of either explicitly listing (either within part 192 or within periodically-issued implementing guidance) historic plastics known to leak, or deleting the scope qualification “historic” from the proposed regulatory text, for the purposes of the proposed annual survey requirement or for replacement under section 114 of the PIPES Act of 2020. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA further proposes to require that operators perform a leakage survey of a distribution pipeline segment after extreme weather events or land movement occur that could damage that segment. This survey must be completed within 72 hours of the cessation of the event, described as the time when the location can be safely

accessed by operator personnel, or alternatively, within 72 hours of when the pipeline is returned to service. Such a survey could qualify as a periodic survey, and therefore reset the one- or three-year clock until the next required periodic survey. Separately, PHMSA proposes to require operators to investigate existing leaks when ground freezing and other changes in environmental conditions (such as heavy rain or flooding-inducing ground subsidence, erosion, or the installation of new pavement) has occurred that could affect gas venting or migration to nearby buildings. The required investigation would include conducting a leakage survey for possible gas migration, but said survey would not qualify as a periodic survey and would not reset the one- or three-year clock until the next required periodic survey. Each of those changes in environmental conditions can place new stresses on pipeline integrity or can affect how and where gas vents from or migrates

through the ground. Therefore, each can cause new leaks or exacerbate or reveal pre-existing leaks on distribution pipelines. These requirements are designed to ensure prompt evaluation of whether environmental changes have exacerbated existing leaks in a way that creates increased risk to public safety and the environment. PHMSA invites comment on whether to require assessments prior to extreme weather events in order for operators to prepare for and prevent resulting leaks.²²⁸ Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

The proposed amendments to gas distribution pipeline leakage survey requirements are summarized in the table below.

SUMMARY OF DISTRIBUTION LEAKAGE SURVEY AMENDMENTS

Facility	Existing	Proposed
Outside of Business Districts	5 years not to exceed 63 months	3 years not to exceed 39 months.
Pipelines known to leak (cathodically unprotected pipe in existing § 192.723).	3 years not to exceed 39 months	Annually, not to exceed 15 months.
Inside Business Districts	Annually, not to exceed 15 months	No change.
Other Proposals	—After environmental changes that can affect gas migration. —Following extreme weather events.	

Note: The most frequent survey would apply.

PHMSA expects its proposed amendments to leakage survey practices would be reasonable, technically feasible, cost-effective, and practicable for affected gas distribution operators. As explained above, operators are already subject to prescriptive periodic leakage surveys and patrols, and individual operators may have more demanding requirements specified within their DIMP plans or as a function of state-imposed requirements; affected operators also have the option to sync their patrol and leakage survey requirements to minimize compliance burdens (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment). PHMSA’s proposed amendments would merely increase prescribed frequencies within Federal regulation as a function of factors (presence of cathodic protection; extreme weather events; material

composition, operating and maintenance history) probative of leak susceptibility—and by extension, risks to public safety and the environment. PHMSA further notes that, insofar as those factors employed in the NPRM as bases for increased leakage survey frequency are widely understood to be potential threats to the integrity of gas distribution pipelines, they are among the phenomena that reasonably prudent operators would evaluate, and potentially adopt mitigation measures to address, in ordinary course when implementing current DIMP requirements to protect public safety from releases of (natural, flammable, toxic, or corrosive) pressurized gases from their pipelines and minimize loss of commercially valuable commodities. Additionally, operators would have flexibility (as appropriate for their needs and their pipelines’ operational characteristics and environment) in

choosing between commercially available, advanced leakage detection equipment satisfying the performance standards proposed in this NPRM for use in those leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding—would provide operators ample time to implement requisite changes in their leakage survey practices and manage any related compliance costs.

In the Preliminary RIA, PHMSA considers an alternative where the 5-

²²⁸ See, e.g., EPA’s notice of proposed rulemaking titled “Accidental Release Prevention Requirements: Risk Management Programs Under the Clean Air Act; Safer Communities by Chemical

Accident Prevention,” 87 FR 53556 (Aug. 31, 2022) (proposing to require, under the Clean Air Act Risk Management Program, that industrial chemical facilities evaluate ways to address natural disasters

and consider steps to prevent releases that may result, even before such events occur).

year survey interval outside of business districts is maintained for plastic pipe distribution pipelines without known leak issues. This alternative is not being proposed because while recent-vintage plastic pipe is understood to leak less than cast iron and bare steel, some studies indicate that plastic piping systems may be leaking more than previously thought.²²⁹ PHMSA invites comment concerning the value of more or less frequent leakage surveys of plastic pipe systems, as well as potential means to identify plastic pipe known to leak (e.g., via a surveillance or sampling program) for inclusion within a final rule in this rulemaking proceeding. Likewise, PHMSA seeks comment on the alternative considered in the Preliminary RIA where distribution mains would be required to be surveyed annually; typically, mains are likely to be more accessible to pipeline operators than service lines crossing private property and may therefore be more convenient to survey. Comments on these questions are especially helpful to PHMSA when they are supported by research or operational experience with leaks from plastic pipe systems or distribution mains (as applicable), along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

2. Transmission and Gathering— §§ 192.9, 192.705, and 192.706

Section 192.706 currently requires gas transmission and Types A and B gathering pipelines that are not odorized to be surveyed with leak detection equipment at least twice each calendar year in Class 3 locations, and at least four times each calendar year in Class 4 locations. All other gas transmission, offshore gathering, Type A and Type B gathering, and certain Type C gathering pipelines must be surveyed once each calendar year. For these annual surveys, PHMSA does not require leak detection equipment on gas transmission and offshore gas gathering pipelines; however, § 192.9 requires the use of leak detection equipment for leakage surveys on Type B and Type C gas gathering pipelines. Section 192.705 specifies frequencies for right-of-way patrols along gas transmission, offshore gathering, and Type A gathering pipelines; Types B and C gathering lines are not required to conduct right-of-way patrols by § 192.705.

Consistent with section 113 of the PIPES Act of 2020, PHMSA proposes to

require the use of leak detection equipment and practices meeting the ALDP standard in proposed § 192.763 (see section IV.B) for leakage surveys on most onshore gas transmission and Types A, B and C gathering pipelines. Leakage survey by human or animal senses would be permitted for offshore gas transmission and offshore gathering pipelines. Because leaks on submerged offshore pipelines are visibly conspicuous due to bubbles or a sheen of gas condensate on the water's surface, PHMSA is not proposing to require leak detection equipment be used for leakage surveys of submerged offshore pipelines, including platform risers up to the waterline. However, offshore platform piping and riser piping above the waterline would be subject to the same equipment and survey requirements as onshore gas transmission pipelines. Leakage surveys for onshore pipelines would be permitted without the use of leak detection equipment (*i.e.*, with human senses or animal senses) only for gas transmission and Types A, B, or C gathering pipelines in non-HCA, Class 1 and Class 2 locations, and then only with prior notification and review by PHMSA pursuant to § 192.18. Visual surveys and other survey methods depending exclusively on human or animal senses would only be authorized if the operator can demonstrate through tests and analyses included in the notification that the survey method would be effective to meet the ALDP performance standard proposed in § 192.763(b) or (c). For example, a visual vegetation survey would need to include procedures to ensure effective detection, such as ensuring the location of a buried pipeline is determined before a survey and performing vegetation surveys on foot rather than at a distance from a vehicle or aircraft, and would not be approved in areas where vegetation is absent. The notification must also include the survey procedures and qualifications for surveyors. Leaks detected on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines would need to be graded and repaired consistent with the requirements proposed in this NPRM (see section IV.C). PHMSA welcomes comments and data on the efficacy of the exclusive use of human senses for leakage surveys, particularly on submerged offshore gas transmission pipelines, submerged offshore gas gathering pipelines, onshore gas transmission pipelines, and regulated onshore gas gathering pipelines (for potential inclusion within a final rule in this proceeding). Comments and data on

this question are especially helpful to PHMSA when they are supported by research or operational experience with the exclusive use of human senses for leakage surveys, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

As explained in section II.C above, leaks from natural gas transmission line pipe are not as significant a source of methane emissions compared with venting, blowdowns, and leaks from compressor stations and other aboveground equipment. However, as explained above in connection with leakage surveys on gas distribution lines, any leaks of methane contribute to climate change and can entail public safety risks—risks that are each more acute for gas transmission pipelines, which generally operate at higher pressures and capacity than distribution pipelines and are usually not odorized. Further, leaks from gas pipeline facilities transporting other flammable, toxic, or corrosive gases can entail significant public safety and environmental consequences. PHMSA therefore proposes, to support more timely detection and repair of leaks that pose a safety hazard, an increase in the minimum leakage survey frequencies for each of the following, calibrated based on a pipeline's proximity to occupied buildings or HCAs: for gas transmission, offshore gathering, and Type A, B, and C gathering pipelines located in HCAs from once each calendar year to twice each calendar year (at intervals not exceeding 7½ months) if within a Class 1, Class 2, or Class 3 location; and for gas transmission and Types A or B gathering pipelines located within Class 4 locations within HCAs, from once each calendar year to four times each calendar year (at intervals not exceeding 4½ months). For gas transmission and Type A or B gas gathering pipelines that are (consistent with the proposed revisions herein to § 192.625) not odorized, more frequent leak surveys would continue to be required to account for the greater risks to public safety from their proximity to occupied buildings: no less than twice each calendar year (at intervals not exceeding 7½ months) for pipelines in Class 3 locations, and no less than four times each calendar year (at intervals not exceeding every 4½ months) in Class 4 locations. Leaks on gas transmission pipelines, especially in Class 3 and Class 4 locations, would also be subject to more stringent grading requirements

²²⁹ Weller et al., 2020, for example.

in the proposed leak grading and repair requirements described in section IV.C.

As explained in section II.C above, fugitive methane emissions from natural gas compressor stations on gas transmission and gas gathering pipelines comprise a significant share of fugitive emissions from those facilities. Other pipeline facilities with relatively complex design and configuration—such as valve sites (including the valve components, flanges, and tie-ins with line pipe), in-line instrument (ILI) launchers and receivers, and tanks—have fugitive emissions profiles better resembling compressor stations than

line pipe. PHMSA therefore proposes more frequent leakage surveys for each of those facilities on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. Such facilities in Class 1, Class 2, and Class 3 locations would need to be surveyed twice each calendar year (at intervals not exceeding 7½ months), compared with once per year under current regulations. This is the same survey interval used for fugitive methane emissions monitoring for compressor stations under the existing and proposed EPA requirements (for example, 40 CFR

60.5397a(g)(2) for new sources). More frequent leakage surveys for such facilities would ensure operators detect and repair leaks earlier, reducing total emissions and reducing the risk that a leak can degrade into a rupture or other incident. Facilities in Class 4 locations would need to be surveyed at least 4 times each calendar year (at intervals not exceeding 4½ months) due to the potential for comparatively more significant public safety risks in the event of a leak due to their proximity to ignition sources and densely occupied buildings.

SUMMARY OF TRANSMISSION AND REGULATED GATHERING LEAKAGE SURVEY AMENDMENTS

Facility	Existing	Proposed
Non-odorized Class 3	Twice a year not to exceed 7½ months	No change.
Non-odorized Class 4	Four times a year not to exceed 4½ months ..	No change.
All other transmission	Once a year not to exceed 15 months	No change.
HCA class 1, 2, or 3	No specific standard	Twice a year not to exceed 7½ months.
HCA class 4	No specific standard	Four times a year not to exceed 4½ months.
Valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and leak prone pipe.	No specific standard	Same as proposed HCA frequencies.
Leak detection equipment	Only required for non-odorized class 3 and class 4.	Required except for non-HCA class 1 and class 2 with a notification.
Regulated gathering	Existing transmission line requirements apply to offshore, Type A, Type B, and certain Type C gathering lines.	Require proposed leakage survey requirements for all regulated gathering lines.

Note: The most frequent survey would apply.

PHMSA also proposes to increase the frequency of patrols on gas transmission, offshore gathering, and Types A, B, and C gathering pipelines by replacing the current, scaled approach within § 192.705(b) of between one and four patrols per year based on class location and the presence of a highway or railroad crossing with a global, baseline requirement for those operators to perform 12 patrols along the entirety of their pipelines each calendar year (at intervals not exceeding 45 days). Patrols are primarily visual surveys of the right of way and may be performed with or without leak detection equipment. PHMSA understands those increased frequencies to be appropriate because patrols are valuable not only for identifying existing leaks and incidents, but also because they are a relatively low-cost method for preemptive identification and mitigation of potential threats to pipeline integrity. In conducting patrols, operators should consider potential threats such as right of way incursions (such as construction, excavation, or agricultural activities), signs of earth movement or flooding, or the presence of new structures potentially indicating a change in class location. In addition to the general leak detection and

pipeline integrity benefits associated with performing right of way patrols described in section IV.A.2, requiring patrols provides an opportunity to update class location surveys and potential impact circle surveys. PHMSA further notes that operators can control their compliance burdens from the proposed increased patrols by coupling them with other operations and maintenance tasks such as leakage surveys (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment) or by leveraging mobile technologies.

PHMSA expects its proposed amendments to leakage survey and right-of-way patrol practices would be reasonable, technically feasible, cost-effective, and practicable for affected gas transmission and gathering pipeline operators. As explained above, operators of affected gas transmission and gathering pipelines (some of which operators have both gas transmission and gathering pipeline facilities within their systems) are already subject to prescriptive periodic leakage surveys requirements; affected operators also have the option to sync their patrol and leakage survey requirements to minimize compliance burdens

(provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment). PHMSA's proposed amendments would merely increase prescribed frequencies within Federal regulation as a function of factors (including location in HCAs and occupied buildings; components/equipment with complex configurations; material composition; operating and maintenance history) probative of leak susceptibility—and by extension, risks to public safety and the environment. PHMSA further notes that, insofar as those factors the NPRM employs as bases for increased leak detection and patrol frequency are widely understood to be potential threats to the integrity of pipelines, they are among the phenomena that reasonably prudent operators would evaluate, and potentially adopt mitigation measures to address, in ordinary course to protect public safety and the environment from releases of pressurized (natural, flammable, toxic, or corrosive) gases from their pipelines and minimize loss of commercially valuable commodities. Additionally, operators would have flexibility (as appropriate for their needs and their pipelines' operational characteristics

and environment) in choosing between commercially available, advanced leakage detection equipment satisfying the performance standards proposed in this NPRM for use in those leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes in their leakage survey practices and manage any related compliance costs.

3. Leakage Surveys and Patrols for Types B and C Gas Gathering Pipelines—§§ 192.9, 192.705, and 192.706

PHMSA proposes to apply to Types B and C gas gathering pipelines the leakage survey and patrol requirements proposed in this NPRM for gas transmission, offshore gathering, and Type A gathering pipelines.

PHMSA has long recognized the public safety risks associated with gathering pipelines and has general authority under 49 U.S.C. 60102 to issue minimum Federal pipeline safety standards necessary to “meet the need for gas pipeline safety [. . .] and protect [] the environment.” For that reason, PHMSA has in the past extended select part 192 requirements—including leak survey requirements at § 192.706—applicable to gas transmission pipelines to a minority (only the largest, or closest to occupied buildings) of the Type C gas gathering pipelines posing the greatest risks to public safety. Existing § 192.9 does not require operators of Type B and Type C gathering pipelines to conduct patrols pursuant to § 192.705.

However, the historical, limited approach in applying §§ 192.705 (patrol) and 192.706 (leakage survey) requirements to Types B and C gathering lines is inadequately protective of public safety and the environment. Recent aerial methane emissions surveys discussed in section II.C above yield that leaks from gas gathering line pipe, the vast majority of which are Type C or Type R pipelines located in Class 1 locations, in particular are a significant contributor to methane emissions. Further, the GHGI

data discussed in section II.E reveals that fugitive methane emissions from all types of gas gathering line pipe vastly exceed emissions from gas transmission line pipe both in total and on a per-mile basis. Leaks from gathering line pipe can therefore be correspondingly greater contributors to the climate crisis than leaks from gas transmission line pipe. Further, because natural gas gathering pipelines carry unprocessed natural gas, any leak from those pipelines would release VOCs and HAPs such as benzene to the environment and risk accelerated degradation of pipeline integrity from corrosives entrained in the natural gas. PHMSA understands that leaks from gathering lines transporting other gases that are flammable, toxic, or corrosive could entail significant public safety and environmental consequences as well. Because of these significant risks to public safety and the environment posed by Types B and C gathering lines, PHMSA has proposed that *all* Type C gathering lines be subject to the same § 192.706 requirements governing leakage survey equipment and frequency as gas transmission and Types A and B gathering pipelines. Similarly, PHMSA proposes to require patrol frequencies for Type B and Type C gathering lines identical to the patrol requirements for as transmission and Type A gathering pipelines. PHMSA understands that its proposed extension of these mutually-reinforcing, enhanced patrol and leakage survey requirements would ensure timely prevention, discovery and remediation of leaks on Types B and C gas gathering lines. PHMSA invites comments concerning the value of requiring more or less frequent leakage surveys of transmission and gathering pipelines (for potential inclusion within a final rule in this proceeding). Comments on these questions are especially helpful to PHMSA when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA expects its proposed amendments to extend leakage survey and right-of-way patrol practices to all Types B and C gas gathering pipeline operators would be reasonable, technically feasible, cost-effective, and practicable. Patrols and leakage surveys using leak detection equipment are widely-employed tools adopted by reasonably prudent operators in ordinary course for identifying and mitigating leaks on, or threats to the

integrity of, pipelines transporting commercially valuable pressurized (natural, corrosive, toxic, or flammable) gases. Precisely for that reason, PHMSA expects that some Types B and C gas gathering pipeline operators affected by this NPRM’s proposed requirements for leakage survey and right-of-way patrols may already voluntarily undertake leakage surveys and patrols on their facilities. Those and other operators of Types B and C gas gathering pipelines (some of which operators may also operate either gas transmission or Type A gathering pipelines) may also have pipelines within their systems subject to prescriptive periodic leakage survey and patrol requirements under Federal or State law. PHMSA’s proposed amendments would, therefore, better align leakage survey and right-of-way patrol practices and requirements for Types B and C gas gathering lines with requirements for other 192-regulated gas pipelines. Additionally, PHMSA’s proposed periodicities for such surveys and patrols would also turn on factors (including location in HCAs and occupied buildings; components/equipment; material composition; operating and maintenance history) well-understood to be probative of leak susceptibility—and by extension, risks to public safety and the environment. Affected operators would also have the option to sync their patrol and leakage survey requirements to minimize compliance burdens (provided that the operator includes both a visual survey of the right-of-way and a leakage survey with leak detection equipment). And operators would have flexibility (as appropriate for their needs and their pipelines’ operational characteristics and environment) in choosing between commercially available, advanced leakage detection equipment satisfying the performance standards proposed in this NPRM for use in their leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite leakage survey and patrol practices and manage any related compliance costs.

PHMSA solicits comment on whether it would be appropriate to apply any of the requirements proposed herein to Type R gathering pipelines not currently regulated under part 192. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

4. Liquefied Natural Gas Facilities— § 193.2624

Part 193 does not currently require that operators perform periodic surveys of LNG facility components and equipment for methane leakage to the atmosphere. However, as described in section II.C.2, equipment leaks and other fugitive methane emissions are the second largest methane emissions source from LNG storage facilities and the largest methane emissions source from LNG export terminals.

PHMSA therefore proposes a new § 193.2624 to require a quarterly methane leakage survey using leak detection equipment and remediation of any methane leaks discovered in accordance with the operator's maintenance or abnormal operations procedures. Leaks discovered would need to be remediated on a schedule established within those procedures. Methane leakage surveys would only need to be conducted on components and equipment containing methane or LNG in normal operations. PHMSA further proposes a minimum equipment sensitivity requirement of 5 ppm—along with validation and calibration requirements—consistent with the proposed requirements governing the performance of leak detection equipment described in section IV.B below for part 192-regulated gas pipeline facilities. PHMSA expects that these proposed enhanced methane leakage and repair requirements would improve public safety by allowing for timely identification and remediation of potential ignition sources within part 193-regulated LNG facilities, as well as reduce a key source of fugitive GHG emissions from those facilities. Additionally, eliminating product losses results in cost savings that improve the competitiveness of LNG storage and export facilities, further increasing the net benefits of this proposal. PHMSA also proposes that, consistent with its proposed revisions to part 191 leak detection and repair reporting requirements for part 192-regulated gas pipeline facilities, PHMSA would propose conforming revisions to its annual report form for part 193-

regulated facilities²³⁰ to ensure meaningful reporting of all methane leaks detected or repaired by operators pursuant to § 193.2624.

PHMSA expects its proposed leakage survey practices would be reasonable, technically feasible, cost-effective, and practicable for affected LNG facility operators. PHMSA notes that some LNG facility operators may operate transmission pipelines supplying natural gas to their facilities; those operators could use their existing leakage survey practices as a foundation for development of leakage survey requirements tailored to their LNG facilities. PHMSA further notes that, insofar as leakage surveys using leak detection equipment are widely understood to be essential tools in identifying and mitigating threats to the integrity of pipelines transporting methane within any gas pipelines, they are among the practices that reasonably prudent operators would adopt in ordinary course to protect public safety and the environment from releases of methane from equipment and components in LNG facilities and minimize loss of a commercially valuable commodity. Additionally, operators would have flexibility in choosing between leakage detection equipment satisfying the performance standard proposed in this NPRM for use in those leakage surveys. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes in their leakage survey practices and manage any related compliance costs.

²³⁰ PHMSA, Form 7300.1–3, “Annual Report Form for Liquefied Natural Gas Facilities (Oct. 2014). The instructions for Form 7300.1–3 states that “a non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak.” PHMSA, Instructions for Form 7300.1–3 at 4 (Oct. 2014). That historical understanding is inconsistent with PHMSA's understanding of the PIPES Act of 2020 premise that all leaks of methane are hazardous to the environment because they contribute to climate change. PHMSA is not, however, proposing in this NPRM to modify the historical reporting exception with respect to releases of other, non-methane, hazardous materials within an LNG facility.

In order to avoid conflicting with existing regulatory requirements and best practices in the National Fire Protection Association standard, “Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)” governing the requirements for LNG facilities (NFPA 59A) and other standard practices, PHMSA has not proposed in this NPRM for LNG facilities a comprehensive, advanced leak detection and repair program framework along the lines of that discussed below in section IV.B for part 192-regulated gas pipeline facilities. For example, section 9.3 of the 2001 edition of NFPA 59A,²³¹ which is incorporated by reference within PHMSA regulations at § 193.2801, requires continuous gas monitoring in the vicinity of LNG process equipment, and section 12.4.2 requires an alarm at 25% LEL or less. Additionally, certain equipment in LNG plants that are not part of distribution systems may be subject to EPA leak detection and repair requirements in 40 CFR part 60 depending on the purpose and contents of the equipment. However, facilities storing or carrying natural gas or LNG are typically subject to the standards for gas production and transmission systems in 40 CFR part 60. The subpart OOOO and OOOOa standards are described in greater detail in section IV.C.3 and include semiannual fugitive emissions monitoring surveys and repair of all leaks visible with an OGI device or that produce an instrument reading of 500 ppm or greater.²³² For a subpart OOOOa facility, the operator must attempt repair no later than 30 days after detecting the fugitive emissions and must complete the repair within 30 days of the first attempt or during the next scheduled shutdown.²³³ Finally, detecting leaks on equipment such as at LNG plants is generally less challenging than doing so on buried pipelines. PHMSA is pursuing a parallel rulemaking (under RIN 2137–AF45) in which it could consider leak monitoring, surveying, and patrolling requirements more holistically.

B. Advanced Leak Detection Programs— § 192.763

Section 113 of the PIPES Act of 2020 requires PHMSA to issue performance standards for operator leak detection and repair programs reflecting the capabilities of commercially available, advanced leak detection technologies

²³¹ NFPA, *NFPA–59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)—2001 Edition* (2001).

²³² 40 CFR 60.5397a(a)(1) and (h).

²³³ 40 CFR 60.5397(h).

and practices. To satisfy this mandate, PHMSA proposes to introduce a new § 192.763 to require operators establish written Advanced Leak Detection Programs (ALDPs) and to establish performance standards for both the sensitivity of leak detection equipment and for the effectiveness of those ALDPs. This new requirement would provide benefits to both public safety and the environment by ensuring that pipeline operators have programs in place to promptly detect and repair leaks of all gas pipelines subject to part 192, thereby reducing harm to public safety and the environment.

An ALDP represents a complementary set of mutually reinforcing technologies and procedures (including analytics) that the operator uses to detect all leaks. PHMSA proposes to require that an operator's written ALDP include four main elements: leak detection equipment employing commercially available advanced technology, leak detection procedures, prescribed leakage survey frequencies, and program evaluation. Note that grading and repairing leaks after investigation is governed by the proposed § 192.760 described in section IV.C of this NPRM. The proposed requirements in this section would apply to operators of all gas distribution lines, gas transmission lines, offshore gathering, and Types A, B, and C regulated onshore gathering pipelines.

PHMSA expects each of the proposed ALDP requirements discussed below would be reasonable, technically feasible, cost-effective, and practicable for all affected gas pipeline operators. PHMSA understands that most operators of gas pipelines that would be subject to those requirements may already employ one or more of its proposed ALDP elements voluntarily because (inter alia) a reasonably prudent operator would in ordinary course employ a systematic, defense-in-depth approach to identifying leaks given the commercial value of, and potential risks to public safety and the environment posed by, the commodities transported (natural gas or flammable, toxic, or corrosive pressurized gases). Alternatively, an operator may employ one or more of PHMSA's proposed ALDP elements as a compliance strategy for existing PHMSA or State leak detection or integrity management requirements. Regardless, PHMSA's

proposals build and on those existing practice by creating a common, straightforward regulatory framework for addressing leak detection across all part 192-regulated gas pipelines. Within that common framework, moreover, operators would retain significant flexibility to select (as appropriate for a pipeline's operational needs and operating environment) a suite of mutually reinforcing leak detection equipment, analytics, and practices, satisfying a baseline leak detection performance standard derived from commercially available advanced leak detection technology in a way that minimizes their compliance costs. PHMSA's proposal even contemplates that some operators of gas pipelines may employ (subject to PHMSA review) an alternative performance standard as a function of location or gas commodity being transported. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite protocols, obtain leak detection equipment, and manage any related compliance costs.

1. Leak Detection Technology Standards—§ 192.763(a)(1)

The first element in an ALDP is the leak detection technology that the operator would use to perform leakage surveys, investigate leaks, and pinpoint leak locations. These technology requirements are proposed in § 192.763(a)(1). Each operator's ALDP would include a list of leak detection equipment that the operator uses for leakage surveys, leak investigations, and pinpointing leaks. Consistent with the mandate in section 113 of the PIPES Act of 2020, PHMSA proposes to specify when leak detection equipment would be required and when an operator may rely on methods that rely on human or animal senses. Specifically, the NPRM

proposes to amend § 192.723 to require that all leakage surveys on gas distribution pipelines be performed with leak detection equipment in light of the high risk to public safety from distribution pipelines, which are often located in the vicinity of population centers. Additionally, as described in section IV.A.2 of this NPRM, all leakage surveys on onshore gas transmission and gathering pipelines performed under § 192.706 would require the use of leak detection equipment, except when the operator of a gas transmission or gathering pipeline in a Class 1 or Class 2 location determines that a survey using human senses would be sufficient, subject to review by PHMSA, as provided in § 192.706(a)(1). This default requirement that ALDPs of onshore regulated gas gathering, transmission, and distribution operators use leak detection equipment in leakage surveys would enhance operators' ability to identify and repair leaks on pipelines in a timely manner, and therefore minimize releases and prevent leaks from degrading. It would also serve to improve leak detection data to improve the predictive power of leak management programs, integrity management programs, and artificial intelligence services that can identify systemic pipeline design or repair issues.

PHMSA further proposes that any leak detection equipment used must have a minimum sensitivity of 5 ppm or less. A reading of 1% of the lower-explosive limit of methane gas at atmosphere is approximately 500 ppm; a minimum sensitivity of 5 ppm would therefore provide a protective threshold of detection sensitivity. That threshold is also consistent with the performance of commercially available leak detection equipment. Table 2 of the Appendix G–192–11 of the GPTC Guide provides examples of commercially available methane detection technologies and the sensitivity and detection ranges for those technologies. That information is reproduced in the table below. In addition to the devices listed below, OGI cameras, devices that are capable of visualizing methane gas leaks and other fugitive emissions, are commonly used for fugitive emissions monitoring at LNG plants, compressor stations, and other facilities.

METHANE LEAK DETECTION TECHNOLOGIES AND PERFORMANCE

Technology	Sensitivity	Range
Semiconductor	1–100 ppm	0–100 ppm.
Flame Ionization	1 ppm	0–10,000 ppm.

METHANE LEAK DETECTION TECHNOLOGIES AND PERFORMANCE—Continued

Technology	Sensitivity	Range
Open Path Infrared (IR) Tunable diode laser absorption spectroscopy.	5 ppm-meter	0–100,000 ppm-meter.
Closed Path Bifringent IR	1 ppm	0–2,500 ppm.
Closed Path IR Laser	0.03–100 ppm	0–1000 ppm.

Although each of the technologies listed above has advantages and limitations that may make it more or less appropriate for leakage surveys on particular gas pipelines or operating conditions, PHMSA's proposed 5 ppm performance standard balances each of the following: a methane sensitivity threshold consistent with the performance of state-of-the-art, commercially-available technologies; robust margin to risk of ignition; and flexibility for operators to choose from a baseline of high-quality equipment for their unique needs. For example, PHMSA understands that modern FID units and closed-path IR and laser-based systems are capable of sub-ppm and parts-per-billion detection. However, quality semiconductor sensors and open-path IR devices have important applications despite comparatively lower-sensitivity. Semiconductor sensors are typically much smaller than other detection devices and therefore are useful in confined spaces and other situations where a smaller tool is necessary to access the space. Additionally, semiconductor sensors are often designed to incorporate intrinsically safe features, which minimizes the risk of ignition in situations where a flammable atmosphere may be present. Similarly, some handheld open-path IR systems can have a sensitivity of 5 ppm-meter at its maximum effective range²³⁴ but have the advantage of allowing a surveyor to detect methane plumes from a distance. This allows operator leakage surveyors to safely and efficiently survey facilities that may otherwise be difficult or unsafe to access. However, the proposed leak detection performance standard would generally exclude each of odorant "sniffers" used to test the adequacy of odorization, less-sensitive combustible gas indicators, and most gas monitors intended for confined space gas monitoring rather than methane leak detection—even as PHMSA acknowledges such devices may nevertheless be useful in connection

with leak grading (pursuant to proposed § 192.760), as tools supplementing ALDP-compliant leak detection equipment, or as authorized pursuant to proposed § 192.763(c).

As discussed throughout this section, other ALDP programmatic requirements backstop any limitations on the ability of particular leak detection technologies to contribute to the program-wide performance standard at § 192.763(b) that an ALDP detects all leaks of 5 ppm or more when measured 5 feet from the pipeline. For example, PHMSA acknowledges that an operator may determine, based on its operational needs or the operating environment of a particular pipeline, that leak detection equipment more sensitive than 5 ppm is necessary to meet the ALDP programmatic performance standard at § 192.763(b). For example, an operator may determine that an efficient means of meeting the ALDP performance standard at § 192.763(b) would be to perform leakage surveys by first using very sensitive (in the sub-ppm or low ppb range) vehicle or aircraft mounted sensors, followed thereafter by spot-checks using handheld devices with the minimum sensitivity of 5 ppm proposed at § 192.763(a)(1)(ii). Similarly, an operator may supplement any leak detection equipment meeting the minimum sensitivity requirements proposed at § 192.763(a)(1)(ii) with other techniques for pinpointing leak location (e.g., soap bubble testing) or technologies (e.g., devices for measuring release rate for differentiating between leak grades) for grading identified leaks pursuant to PHMSA's proposed § 192.760.

PHMSA further notes that operators would be able to, pursuant to the proposed § 192.763(c), seek PHMSA review of use of an alternative ALDP performance standard that may entail the use of alternative (including less sensitive) leak detection technology than that proposed under § 192.763(a)(1). This process is available for each of natural gas pipelines (other than distribution pipelines) in Class 1 and 2 locations, and any part 192-regulated pipeline facility transporting flammable, toxic, or corrosive gas other

than natural gas.²³⁵ PHMSA acknowledges the fast-evolving state-of-the-art in leak detection technologies for methane and other gases and seeks comments on whether and in what manner it could integrate within a final rule requirements for technologies that may not have specified sensitivities, including continuous pressure wave monitoring, fiber optic sensing, OGI, and LIDAR based detection technologies, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable). PHMSA expects that it would consider the use of such technologies under the § 192.763(c) process or as supplement to other equipment satisfying the minimum sensitivity performance requirements proposed herein.

Apart from minimum sensitivity requirements described above, PHMSA does not propose to require the use of any particular leak detection equipment or technology for every operator or for each type of pipeline. While the PIPES Act of 2020 directs PHMSA to require the use of advanced leak detection technologies and practices, Congress defined this requirement in terms of a performance standard for leak detection and repair programs and described several possible approaches in the statute. PHMSA therefore does not propose to narrowly define advanced leak detection in terms of a particular technology, process, manufacturer, or equipment. One type of technology may not always be appropriate for every flammable, corrosive, or toxic gas, each type of pipeline facility or even across

²³⁵ Although PHMSA's proposed 5 ppm default performance standard for all part 192-regulated gas pipelines is based principally on commercially available, advanced methane leak detection technology for use with natural gas pipelines, PHMSA understands that commercially available, advanced leak detection technology for use with other part 192-regulated gas pipeline facilities may (when considered either separately or within a suite of mutually-reinforcing technologies) offer comparable leak detection ability. Further, as explained in the paragraph above, the NPRM contemplates operators of gas pipeline facilities transporting gases other than natural gas (e.g., hydrogen) may request the use of an alternative leak detection performance standard and supporting leak detection equipment.

²³⁴ PPM-meter is a "path integrated" summation of measured gas concentration used for open-path devices that sums gas concentration per meter measured up to the effective range in front of the device. Sensitivity may be higher at closer ranges depending on the specific technology used.

the range of operational/environmental conditions (e.g., seasonal temperature, humidity, or precipitation patterns) within which a particular pipeline operates. Rather than a technology standard, PHMSA expects each of the periodic evaluation and improvement element of each ALDP (proposed in § 192.763(a)(4)), and the ALDP performance requirement (proposed in § 192.763(b), described later in this section), would encourage operators to continually evaluate and incorporate within their ALDPs such newly commercialized technologies as appropriate for their systems over time. This flexible approach would ensure that operators' leak detection equipment keeps pace with the state-of-the-art in leak detection technology. Additionally, this NPRM proposes to require operators to select their leak detection equipment based on a documented analysis that considers, at a minimum, the gas being transported, the size, configuration, operating parameters, and operating environment of the operator's system. An operator would be required to choose leak detection technologies that are best able to detect, investigate, and locate all leaks considering these factors. For example, an advanced mobile leak detection system could be an effective tool for detecting methane leaks in a suburban distribution system but may not be optimal for surveying service lines in an area with long setbacks or a transmission pipeline with poor road access. PHMSA also proposes to require operators to analyze, at a minimum, the appropriateness of the following examples of possible advanced leak detection technologies and methods, some of which were referenced in the PIPES Act of 2020: leakage surveys with optical, infrared, or laser-based handheld devices; continuous monitoring via stationary gas sensors, pressure monitoring, or other means; mobile surveys from vehicle, satellite, or aerial platforms; and systemic use of other technologies capable of detecting and locating leaks consistent with the proposed ALDP performance standard at § 192.763. Operators would be required to maintain records of this analysis for five years. Stationary gas detection systems are already required on compressor stations under PHMSA's existing regulations at § 192.736. Likewise, section 16.4 of the 2001 edition of NFPA 59A,²³⁶ which is incorporated by reference into the federal safety standards for LNG

facilities in part 193, requires monitoring of enclosed buildings and other areas that can have the presence of LNG or other hazardous fluid (including natural gas), and specifies flammable gas alarm settings in section 16.4.2. PHMSA invites comments on the value of introducing requirements for continuous monitoring systems, via stationary gas detection systems, pressure monitoring, or other means (including requirements for the use of specific methods or technologies), on other types of pipeline facilities (including whether continuous monitoring would be most appropriate at any particular facilities or locations, or in other particular conditions) within a final rule in this rulemaking proceeding.²³⁷ Comments are especially helpful to PHMSA when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

2. Leak Detection Practices— § 192.763(a)(2)

The second program element in proposed § 192.763(a)(2) consists of the operator's procedures related to leak detection, investigation, and location. Generally, this would involve supplementing or revising existing procedures in the operator's manual of procedures. At a minimum, the ALDP would include procedures for performing leakage surveys as well as subsequent investigation and location of identified leaks; operator procedures would provide instruction on whether and how each type of leak detection equipment included in the ALDP would be used in performing those tasks. To ensure that operators use procedures appropriate for environmental conditions such as temperature, wind, time of day, precipitation and humidity, the operator must define under which conditions the procedure may and may not be used. Additionally, the procedures must be consistent with any instructions and allowable operating and environmental parameters issued by the leak detection equipment manufacturer to ensure equipment effectiveness. For example, some devices or systems may be unsuitable for use in certain weather or atmospheric conditions, or at certain

times of day, or in certain temperatures. As noted in the discussion of leak detection practices in section II.F, establishing and following procedures with parameters appropriate for the leak detection technologies and practices is critical for reliably detecting leaks, especially in challenging conditions. This requirement also addresses the findings from the NTSB's investigation of a 2018 gas explosion involving failed leakage surveys (discussed in section II.H of this NPRM.) due to the operator's improper use of leak detection equipment.²³⁸

PHMSA proposes to require that an operator's ALDP procedures include investigating and pinpointing the location of all leak indications. For onshore pipelines and offshore pipeline facilities above the waterline, PHMSA proposes in § 192.763(a)(2) to require that pinpointing location be performed using handheld leak detection equipment with a minimum sensitivity of 5 ppm. This proposed requirement would complement PHMSA's proposed ALDP programmatic performance standard in § 192.763(b). If leak location is pinpointed with handheld leak detection equipment during an initial leakage survey, the initial survey would satisfy this requirement. PHMSA proposes that pinpointing leak location on submerged offshore pipelines (including riser piping up to the waterline) would not require the use of leak detection equipment because submerged pipeline leaks are visibly conspicuous.

To ensure the effectiveness of leak detection equipment, PHMSA proposes to require at § 192.763(a)(2)(iii) that an operator have procedures for validating that a leak detection device meets the 5-ppm minimum sensitivity requirement in § 192.763(a)(1)(ii) prior to initial use. This would consist of testing the equipment measurements against a known concentration of gas. Operators would have to maintain records that their leak detection equipment has been validated for five years after the date each device ceases to be used in the operator's ALDP. This is a one-time validation separate from the periodic calibration required under proposed § 192.763(a)(2)(iv) described below. PHMSA also proposes to require that operators have procedures for the maintenance and calibration of leak detection equipment—including at least

²³⁶ NFPA, *NFPA-59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)—2001 Edition* (2001).

²³⁷ To the extent that a comment proposes to require installation of such technologies on a pipeline, PHMSA also solicits comment on the potential application of PHMSA's statutory prohibition on retroactive design and installation standards. See 49 U.S.C. 60104(b).

²³⁸ National Transportation Safety Board. "Pipeline Accident Report: Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018." NTSB/PAR-21/01. Jan. 12, 2021. Washington, DC <https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR2101.pdf>.

any maintenance and calibration procedures recommended by the equipment manufacturer—to ensure that equipment is functioning as intended throughout its service life. Finally, PHMSA proposes to require that operators recalibrate leak detection equipment following an indication of malfunction.

3. Leakage Survey Frequency— § 192.763(a)(3)

The third element that PHMSA proposes to require of an ALDP is the frequency of leakage surveys, which is specified in proposed § 192.763(a)(3). Minimum leakage survey frequencies are defined in § 192.723 for gas distribution pipelines and in § 192.706 for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. As noted in section IV.A, less sensitive survey equipment may require more frequent surveys in order to provide an equivalent degree of leak or emissions detection.²³⁹ If more frequent leakage surveys are necessary to reliably meet the ALDP programmatic performance standard in proposed § 192.763(b), or as otherwise specified by the operator, that must be noted in the operator's ALDP. For example, more frequent leakage surveys may be appropriate for less sensitive leak detection equipment authorized for use pursuant to proposed § 192.763(c), challenging survey conditions, or facilities known to leak based on their material, design, or past operating and maintenance history. As noted above in section IV.B.1, PHMSA invites comments on the value of requiring continuous monitoring systems on these types of facilities or any other pipeline facilities (for potential inclusion within a final rule in this proceeding). Comments are especially helpful to PHMSA when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

4. Program Evaluation and Improvement—§ 192.763(a)(4)

The fourth and final element of an ALDP in § 192.763(a)(4) is program evaluation and improvement. At least annually, operators would have to re-

evaluate the elements of their ALDPs considering, at a minimum, the performance of the leak detection equipment used, the adequacy of their leakage survey procedures, advances in leak detection technologies and practices, the number of leaks initially detected by third parties, the number of leaks and incidents on the pipeline, and estimated emissions from detected leaks. This proposal is similar in principle to the existing continuous improvement requirements under IM requirements in part 192, subparts O and P, as well as requirements for certain operators to periodically review procedures under § 192.605(b)(8) and (c)(4). PHMSA expects this proposal would ensure operators periodically evaluate ways to improve their leak detection programs based on leak detection performance data and advances in technology. For example, if an operator finds evidence that their ALDP fails to detect leaks during leakage surveys, or that it is finding grade 1 or 2 leaks but does not find any grade 3 leaks, changes to program elements may be necessary to ensure that the minimum performance standard in § 192.763(b) described below is met. This provision would offer potential environmental benefits and could also result in cost-savings to operators and shippers, by helping further reduce product losses from pipeline facilities.

5. Advanced Leak Detection Performance Standard—§ 192.763(b)

The ultimate benchmark for the effectiveness of an operator's ALDP would be a holistic, program-wide performance standard at § 192.763(b). Specifically, PHMSA proposes to require that an ALDP must be capable of detecting all leaks that produce a reading of 5 ppm or greater of gas when measured from a distance of 5 feet from the pipeline, or within a wall-to-wall paved area. As described in the discussion of leak detection equipment above, the proposed 5 PPM standard represents a protective, detection threshold achievable using mainstream, commercially available, advanced leak detection equipment. The § 192.763(b) ALDP performance standard is consistent with that minimum sensitivity for leak detection equipment, but it focuses on the characteristics of the leak (in particular, whether the leak rate or operating environment results in a reading of 5 ppm) rather than on the sensitivity of the leak detection equipment employed by an operator. For example, a walking survey conducted alongside a pipeline with thorough, careful, procedures to ensure detection of all leaks could achieve this

standard with an FID or other handheld device with the 5 ppm sensitivity required by § 192.763(a). But mobile leak detection systems and aerial systems that use gas samplers or other sensors to detect leaks at a greater distance may allow for more efficient leakage surveying, but could require more sensitive (sensors in the ppb range) leak detection equipment coupled with advanced analytics (followed by the use of handheld leak detection equipment to pinpoint leak location) to detect and locate the same leak. Similarly, leakage surveys employing human or animal senses would have to employ leak detection equipment to investigate and pinpoint the location of any leaks detected during those non-instrumented surveys.

Some stakeholders attending the 2021 Public Meeting commented that leak flow rate would be a more appropriate metric for leak detection and ALDP program performance than PHMSA's proposed volumetric sensitivity metric.²⁴⁰ However, as discussed above in section II.D.4, most currently available methane leak detection technologies are focused on calculating the concentration of gas in the air rather than leak flow rate. Moreover, PHMSA's choice of leak concentration-based performance standard for leak detection equipment was informed by the goal of (as much as possible) identifying a single performance standard that would be well-suited for leak detection on both aboveground and buried natural gas pipelines. Additionally, consistent with the GPTC Guide grading criteria and as acknowledged in the comments of AGA et al. to the 2021 Public Meeting, a concentration-based metric is especially useful for addressing explosion risks to public safety (regardless of a leak's flow rate). To the extent that operators find that leak rate measurements are helpful for identifying or grading leaks or in calculating estimated emissions consistent with changes to part 191 reporting requirements discussed elsewhere in this NPRM, operators may incorporate leak flow rate metrics within their ALDPs to supplement leak concentration metrics used in PHMSA's proposed leak detection and ALDP performance standard. In particular, leak rate measurements may help operators quickly grade certain leaks as grade 2 leaks based on a leak rate in excess of 10 CFH. Based on available

²³⁹ Ravikumar, Arvind Ph.D. "FEAST-Based Evaluation of Methane Leak Detection and Repair Programs Using New Technologies." EPA Methane Detection Technology Workshop (August 24, 2021). <https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-methane-detection-technology-workshop>. Day 2 at 1:33:50.

²⁴⁰ Written comments submitted before and after the meeting are available in the rulemaking docket at Doc. No. PHMSA-2021-0039. While some commenters observed that a leak flow rate performance standard would be desirable, no commenter provided a suggestion for how this could be implemented.

information, PHMSA's current assessment is that the proposed § 192.763(b) ALDP performance standard represents a threshold of detection demanding enough to ensure that operator ALDPs are capable of detecting nearly all leaks on gas gathering, transmission, and distribution pipelines. That said, PHMSA invites comment on whether and how an alternative ALDP performance standard—such as a more demanding volumetric standard, or a flowrate-based standard—should be adopted in the final rule. Proposed alternatives are most helpful when they are supported by a discussion of their value for public safety and environmental protection, as well as their technical feasibility, cost-effectiveness, and practicability.

6. Alternative Advanced Leak Detection Performance Standard—§ 192.763(c)

Lastly, because of the comparatively low emissions from natural gas transmission pipeline leaks (relative to other gas transmission pipeline facilities such as compressor stations),²⁴¹ comparatively lower potential safety risks to persons or property in remote areas, and the continued development of methane leak detection technologies, PHMSA proposes, at § 192.763(c), to allow operators of each of gas transmission, offshore gathering, and Types A, B, and C gathering pipelines, located in Class 1 or 2 locations and outside of HCAs to request an alternative ALDP performance standard (and use of supporting leak detection equipment) pursuant to the notification and PHMSA review procedures established in § 192.18. PHMSA similarly proposes that operators of any species of part 192-regulated gas pipelines transporting flammable, toxic, or corrosive gases other than natural gas may request use of an alternative ALDP performance standard (and use of supporting leak detection equipment).

The operator must demonstrate, in the notification, that the alternative performance standard is consistent with pipeline safety and equivalent to the performance standard in § 192.763(b) with respect to reducing greenhouse gas emissions and other environmental hazards. This flexibility can promote emerging technologies where they may be most effective. For example, some aerial survey methods may not yet be able to detect small but potentially hazardous, below-ground methane leaks from a distribution pipeline system, but they could be an efficient leakage survey

method for leaks on below-ground onshore gas transmission lines, which leaks are larger on average due to the higher operating pressure. Similarly, an alternative performance standard may be appropriate for flammable, toxic, or corrosive gases for which commercially available, advanced leak detection technology either uses different units of measure than that provided for in § 192.763(a) or is less sensitive than the default 5 ppm performance standard. PHMSA proposes to require that notifications submitted under this provision must include information about—among other things—the location and material properties of the pipeline facility, the gas being transported, a description of the proposed alternative performance standard, and a description of the ALDP equipment and procedures that would be used.

C. Leak Grading and Repair— §§ 192.703, 192.760, and 192.769

As discussed in section II, gas pipeline operator leak grading and repair practices are currently insufficient to meet the threats to the environment and public safety from leaks on their systems. Current requirements lack meaningful requirements for timely grading and repair of leaks; only leaks that are “hazardous” (a term that is undefined) are subject to explicit repair timelines and requirements, and PHMSA's IM regulations in subparts O (transmission) and P (distribution) largely defer to operator discretion regarding leak repair efforts for the small portion of gas pipelines subject to those requirements. Only a handful of States have imposed their own, more demanding leak repair requirements than PHMSA's. Similarly, while some operators have voluntarily adopted their own leak grading and repair practices, many operators have no such requirements, and those that do may not apply these requirements consistently across different types of pipeline facilities.

PHMSA therefore proposes to address these regulatory gaps by establishing requirements at §§ 192.703, 192.760, and 192.769 for all part 192-regulated gas pipeline operators to ensure properly-trained personnel grade and repair all leaks pursuant to a schedule for each grade based on the severity of public safety and environmental risks.²⁴² PHMSA's proposal includes a

leak grading framework informed by the criteria of the GPTC Guide—which is familiar to industry and State enforcement personnel—to facilitate compliance and regulatory oversight. PHMSA's proposed leak grading framework in § 192.760 would require the classification of every leak on any portion of a gas pipeline (including components such as flanges, meters, regulators, and ILI launchers and receivers) as either (in order of decreasing priority) grade 1, grade 2, or grade 3 based on the magnitude and probability of risks posed by that leak to the public and the environment, prioritizing remediation of leaks presenting the most serious hazards to people or the environment and setting minimum repair timelines for each grade. Operators would be obliged to investigate each leak discovered on their pipelines immediately and continuously until a leak grade determination has been made to ensure that risks to public safety and the environment from each leak are diligently evaluated and repairs scheduled as appropriate to remedy any risks. The NPRM also includes a number of enhancements to the GPTC Guide's three-tiered framework to address gaps in safety and environmental protection, including establishment of repair deadlines for grade 3 leaks and incentivizing replacement or remediation of pipe known to leak. Operator personnel engaged in leakage survey, investigation for grading purposes, and repair would be subject to baseline training requirements. Lastly, PHMSA has proposed revision of the documentation requirements at § 192.605, consistent with statutory language in section 114 of the PIPES Act of 2020, to oblige operators of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines to update their procedures to provide for the replacement or remediation of pipelines known to leak.

PHMSA expects each of the proposed leak grading and repair requirements discussed in this section IV.C would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. As explained above, some operators that would be subject to this NPRM's proposed requirements have one or more pipelines within their systems that are already subject to some leak repair (either prescriptive or integrity management-based) requirements under PHMSA or State regulatory regimes. Other operators may voluntarily exceed minimum regulatory

²⁴¹ See the discussion of GHGI data in section II.E. of this NPRM.

²⁴² These grading requirements apply to all commodities transported under part 192, including petroleum gas, as all non-natural gas commodities covered under part 192 are hazardous to human health or the environment. See § 192.3 (definition of gas). Petroleum gas systems are subject to some

specialized grading criteria due to the unique hazards posed by this heavier-than-air gas.

requirements given the significant public safety and environmental risks posed by releases of pressurized (natural, flammable, toxic, or corrosive) gas from their pipelines, or to minimize loss of commercially valuable commodity. PHMSA's proposal builds on those existing practices by establishing for part 192-regulated gas pipelines a common leak repair obligation leveraging the GPTC Guide's familiar framework for classifying *all* leaks—not merely those thought to pose imminent risks to public safety. PHMSA in turn calibrated its proposed repair timelines for each leak grade based on the magnitude of public safety and environmental risks; within those default repair timelines, operators may be able to seek extensions or (with respect to compressor stations) be relieved of obligations from potential overlapping requirements from certain methane emissions requirements imposed by other Federal and State regulatory authorities. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite leak grading and repair protocols (including, but not limited to, those pertaining to procedure development, post-repair inspection, and recordkeeping) and manage any related compliance costs.

1. Leak Repair Requirement—§ 192.703(c)

Consistent with the proposed new leak grading and repair requirements at § 192.760(c) discussed below, PHMSA proposes to eliminate the current limitation of operators' repair obligation to leaks that are "hazardous" to public safety. To accomplish this, PHMSA proposes to revise § 192.703(c) to require grading and repair criteria for *all* detected leaks. Additionally, PHMSA proposes that its expanded leak repair obligations would attach to all part-192 regulated gas pipelines because any leak from those pipelines entails risks to one or both of public safety and the environment. While any leak of methane from a gas pipeline system necessarily entails environmental harm

proportional to the amount of methane released to the atmosphere, PHMSA proposes introducing minimum sensitivity standards for leak detection equipment at § 192.763 (discussed below) in recognition that some leaks are so small that the harm they present does not warrant expending the resources necessary to detect and repair them, particularly where the leak is approaching the limits of detection with commercially available advanced technologies. This approach is consistent with Congress's direction in the PIPES Act of 2020 for PHMSA to require that operators repair or replace "each leaking pipe, except a pipe with a leak so small that it poses no potential hazard." Under the proposed approach, some very small leaks which would escape detection would not qualify as a "leak or hazardous leak" under § 192.3, and thus would not be repaired.

2. Replacement of Pipelines Known to Leak—§ 192.605

Among the self-executing mandates within section 114 of the PIPES Act of 2020 is a requirement that pipeline operators update their procedures to provide for minimizing releases of natural gas; eliminating hazardous leaks of natural gas and any other flammable, toxic, or corrosive gas; and the replacement or remediation of pipelines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history. PHMSA proposes to incorporate that self-executing statutory language within § 192.605's list of prescribed content for the operations, maintenance, and emergency procedures of gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines. Affected operators may implement this proposed regulatory amendment by updating (to the extent they have not done so already in complying with the self-executing statutory mandate) their operating, maintenance, and emergency procedures to contain protocols guiding decision-making on whether replacement or remediation of a particular pipeline or its components would be a more durable and effective solution for remediating or preventing leaks that entail public safety and the environmental harms. PHMSA submits that operator protocols could (in addition to referencing the leak-prone materials identified in section 114 language) reference authoritative resources (e.g., State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports and

advisory bulletins, NTSB findings, or industry efforts) to assist in identifying pipelines known to leak and evaluating whether replacement or remediation would be more appropriate in each case, as discussed in the context of distribution pipeline leakage surveys in section IV.A.1. PHMSA invites comment on the value of either explicitly listing leak-prone materials (either within part 192 or within periodically-issued implementing guidance). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA's proposed revision to § 192.605 addressing replacement of pipelines known to leak would apply only to gas transmission, distribution, and part 192-regulated gathering lines which are subject to the self-executing statutory mandate. The more general requirement from section 114 of the PIPES Act to have procedures addressing minimizing releases of natural gas are proposed for part 192-regulated gas pipeline facilities in § 192.605, UNGSFs in § 192.12, and LNG facilities in §§ 193.2503 and 193.2605. That proposal is discussed in section IV.F. PHMSA solicits comment regarding whether any final rule in this rulemaking proceeding should extend the proposed revision addressing replacement of pipelines known to leak to gas pipeline facilities other than piping systems (in particular, part 193 LNG facilities and UNGSFs). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

3. Compressor Stations—§ 192.703(d)

As described in section II.B of this NPRM, EPA has imposed methane emissions standards at 40 CFR part 60 for the oil and gas industry establishing fugitive emissions monitoring and repair requirements for gas transmission compressor stations and gas gathering boosting stations constructed, reconstructed, or modified after September 18, 2015 (subpart OOOOa). EPA has also proposed (1) a new 40 CFR part 60, subpart OOOOb that would update standards for gas transmission compressor stations and gas gathering boosting stations installed, reconstructed or modified after November 15, 2021, and (2) nationwide emissions guidelines that would be

located at 40 CFR part 60, subpart OOOOc addressing methane emissions from oil and gas existing sources including fugitive emission components at existing gas transmission compression stations and gas gathering boosting stations that would not be subject to its proposed 40 CFR part 60, subpart OOOOb standards.²⁴³

Given EPA's existing and proposed robust methane emissions standards, PHMSA proposes a narrow exception from some of the proposed requirements for gas transmission and gas gathering compressor stations that would already be subject to monitoring and repair requirements within EPA's current 40 CFR part 60, subpart OOOOa regulations, proposed subpart OOOOb updates and subpart OOOOc methane emissions guidelines (as implemented through EPA-approved State plans with standards at least as stringent as EPA's emission guidelines in subpart OOOOc or implemented through a Federal plan).²⁴⁴ Specifically, PHMSA proposes exception from each of its requirements pertaining to leak repair (§ 192.703(c)), leakage survey and patrol (§§ 192.705 and 192.706), leak grading and repair (§ 192.760), ALDPs (§ 192.763) and qualification of leak detection personnel (§ 192.769). Operators would, notwithstanding the exception from other elements of § 192.760, remain obliged to retain records associated with leak repairs pursuant to § 192.760(i) to ensure appropriate documentation of change and trend analysis on those facilities, as well as adequate documentation to support regulatory oversight activity by pertinent State and Federal regulatory authorities. To establish clear boundaries for the exception, PHMSA proposes that the exception would cover those components located within the first block valve entering or exiting the facility (exclusive of that block valve)—which valves mark the boundary of station overpressure protection pursuant to § 192.167.

EPA's proposed regime at 40 CFR part 60 for monitoring fugitive methane emissions from gas transmission compression stations and gas gathering boosting stations provides public safety and environmental protection comparable to PHMSA's proposals in this NPRM.²⁴⁵ EPA regulations at 40

CFR 60.5397a(g)(2) within subpart OOOOa require quarterly²⁴⁶ methane emissions monitoring surveys of leaks from all gas transmission compression and gas gathering boosting systems—more frequent than PHMSA's proposed leakage survey revisions for all but those facilities in HCAs within Class 4 locations. EPA requirements require those surveys be performed using leak detection equipment—either optical gas imaging or another “instrument” (such as FID) with sensitivity of at least 500 ppm that complies with method DA in appendix A–7 to 40 CFR part 60—standards that are similar to the leak detection equipment contemplated by this NPRM. EPA regulations require an operator first attempt repair of any fugitive emissions so detected within 30 days and complete repairs within 30 days of that first attempt—equivalent to the 30-day repair timeline for grade 2 gas transmission pipeline leaks in HCAs and class 3 and class 4 locations proposed in this NPRM but more aggressive than the proposed 6-month timeline for repair of grade 2 leaks in non-HCA class 1 and class 2 locations. And although the EPA's repair timelines may be less demanding than those proposed in this NPRM for grade 1 leaks, PHMSA understands that EPA's more frequent required surveys would ensure timely detection and remediation of leaks on gas transmission compression stations and gas gathering boosting stations. Further, allowing operators to direct compliance efforts toward EPA's regulatory regime rather than proposing additional requirements for EPA-regulated facilities ensures that operator resources are focused on

accompanying methane emissions guidelines at subpart OOOOc (existing sources) are not yet final; however, PHMSA considers the monitoring and repair elements of those proposals to be at least as protective of public safety and the environment as corresponding existing requirements 40 CFR part 60, subpart OOOOa. However, should proposed subparts OOOOb and OOOOc not be finalized, only gas transmission compression and gas gathering boosting stations subject to 40 CFR part 60, subpart OOOOa would be eligible for the exception proposed in this NPRM.

²⁴⁶ While the final rule titled “Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Review” (85 FR 57018 (Sept. 14, 2020)) removed all methane standards from 40 CFR part 60, subpart OOOOa, including the quarterly monitoring and repair requirements for methane fugitive emissions at compressor stations at 40 CFR 60.5397a(g)(2), Congress subsequently disapproved that final rule by a joint resolution (Pub. L. 117–23) enacted pursuant to the Congressional Review Act (Pub. L. 104–121). The president signed that joint resolution into law. As a result, the EPA's September 2020 final rule is treated as if it had never taken effect, and the methane standards in subpart OOOOa promulgated in 2016 remain in effect. See EPA's Q&A for more information. https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.

methane emissions reduction rather than overlapping compliance frameworks.

In the event that EPA's proposed regulations at subparts OOOOb and OOOOc are not in effect because they have not yet been finalized or for any other reason, the proposed exception would not apply and the leak detection, grading, and repair requirements proposed herein would apply to gas transmission and gas gathering compressor station facilities.

PHMSA invites comment on the appropriateness of this proposed exception and the specific regulatory requirements within its proposed scope (to include comments regarding any potential regulatory gaps that may arise from this exception) for consideration in any final rule in this proceeding. Should stakeholders submit proposed alternatives content for this exception, those alternatives would be most helpful if they are supported by evaluation of the safety or environmental benefits, technical feasibility, cost-effectiveness, and practicability.

4. Grade 1 Leaks—§ 192.760(b)

A grade 1 leak is the highest priority grade and represents an existing or probable hazard to persons, property, or an existing, grave hazard to the environment. A grade 1 leak is an urgent or emergency situation—for this reason, PHMSA proposes that operators must be required to take “immediate and continuous” action to eliminate the hazards to public safety and the environment. As soon as an operator determines a grade 1 leak exists, it must immediately dispatch personnel to address hazards to people or the environment and undertake other actions (including, but not limited to, those identified at proposed § 192.760(a)(2), most of which track requirements elsewhere in PHMSA regulations) to minimize risks to public safety and the environment. The appropriate “immediate and continuous action[s]” taken by an operator would necessarily depend on the nature of the leak and pipeline operational and environmental conditions. For example, the “immediate and continuous action[s]” required of the operator of a submerged, offshore pipeline in responding to a grade 1 leak on its system may entail different engineering actions or considerations than an operator of an onshore, non-buried, low-pressure pipeline with a grade 1 leak.

²⁴³ See EPA SNPRM.

²⁴⁴ Gas pipeline facilities that would be subject to this proposed exception would remain PHMSA-jurisdictional gas pipeline facilities otherwise subject to parts 191 and 192 requirements and PHMSA regulatory oversight.

²⁴⁵ EPA's updated methane emissions new source performance standards in its proposed 40 CFR part 60, subpart OOOOb (new sources) and

PHMSA's proposed grade 1 leak criteria elaborate that, at a minimum,²⁴⁷ a grade 1 leak includes any of the following characteristics:

- Any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to be an existing or probable hazard to persons or property, or a grave hazard to the environment;
- Any amount of escaping gas that has ignited;
- Any indication that gas has migrated into a building, under a building, or into a tunnel;
- Any reading of gas at the outside wall of a building, or areas where gas is likely to migrate to an outside wall of a building;
- Any reading of 80% or greater of the LEL in a confined space;²⁴⁸
- Any reading of 80% or greater of the LEL in a substructure (including gas associated substructures of a gas pipeline or non-associated gas pipelines), from which gas would likely migrate to the outside wall of a building;
- Any leak that can be seen, heard, or felt by human senses; or
- Any leak reportable as an incident as defined in § 191.3.

PHMSA's proposed grade 1 leak criteria resemble those in the GPTC Guide and, consistent with that framework, are intended to prioritize for immediate repair those leaks that pose a significant hazard to people and property. However, PHMSA proposes important differences designed to address gaps in safety and environmental protection. First, PHMSA proposes to characterize a grade 1 leak to include leaks with grave environmental harms. Including such leaks in the grade 1 leak criteria is consistent with the mandate for this NPRM in section 113 of the PIPES Act of 2020 and would reduce public safety risks. Any leak of methane from a gas pipeline system necessarily entails environmental harm proportional to the total release volume by contributing to

climate change. PHMSA's proposed language therefore distinguishes between public safety risks (which can be *existing* or *contingent* under the historical GPTC Guide framework) and the *certain* environmental harms from leaks of methane and other gas. PHMSA proposes grade 1 criteria scaled language ("grave hazard to the environment") to acknowledge the magnitude of that harm from methane or other gas released from leaks can vary from one leak to the next. A leak satisfying one or more of its proposed grade 1 criteria would be a release of gas involving a risk of ignition that is sufficient to be an existing or probable future hazard to public safety, or release of sufficient volume that poses a grave hazard to the environment.

Proposed § 192.760(b)(1)(vi) also classifies as a grade 1 leak any reading of 80% LEL or greater in a substructure (subterranean structures too small for a human to enter) from which gas would likely migrate to the outside wall of a building. Unlike the GPTC Guide, the proposed criteria would include substructures associated with the operator's gas pipeline. A gas-associated substructure includes facilities such as small valve boxes and other vaults not intended for human entry. While it is not unusual for some gas to accumulate in gas-associated substructure, a potentially explosive concentration of gas with the potential to migrate to nearby buildings is an immediate public safety hazard regardless of whether a substructure is associated with a gas pipeline or not. PHMSA also proposes conforming revisions to § 192.3 to introduce definitions for the terms "substructure," "gas-associated substructure," and "confined space" to facilitate operator compliance and PHMSA and State regulatory oversight.

Proposed § 192.760(b)(1)(vii) would classify any leak that can be seen, heard, or felt as a grade 1 leak. In comparison, Table (3a) in the GPTC Guide limits this criterion to leaks that are in a location that may endanger the public or property. Applying the seen, heard, or felt criteria to leaks regardless of location ensures operator field personnel have a standard for classifying leaks that potentially cause significant environmental or safety consequences in the form of methane emissions and other pollutants. The visible indications of a gas leak may include for example, ground disturbances, a jet or vapor cloud of condensation, or blowing debris. A gas leak can also emit a hissing sound or, for larger leaks, sounds resembling a jet engine or train. Tactile indications of a leak include force from a jet of gas or

vibrations in the pipe or soil. Each of these physical markers of a pipeline leak are typically more apparent on higher-pressure, larger volume leaks. PHMSA does not consider impacts to vegetation to be a definitive indication of a grade 1 leak for these purposes. However, an operator should consider if there are severe or widespread impacts to vegetation during a leakage investigation. Additionally, a leak on an offshore pipeline that is visible from the surface (*i.e.*, bubbles or condensate sheen) would be classified as a grade 1 leak under this criterion.

Lastly, PHMSA proposes that any leak reportable as an incident under part 191 would be classified as a grade 1 leak. The definition of "incident" in § 191.3 would include any event involving the release of gas from a pipeline that results in one or more of the following consequences:

- A death or personal injury necessitating in-patient hospitalization;
- Estimated property damage of \$129,300, excluding the cost of lost gas, (adjusted for inflation for calendar year 2022); or
- Unintentional estimated gas release of 3 MMCF or more.

This criterion would address gaps in the GPTC Guide's current grade 1 leak criteria and would help ensure the repair of leaks that involve very large release volumes, or which are known to result in significant public safety and environmental harms. Further, if a previously detected leak later results in an incident causing significant safety and environmental consequences, then it almost certainly would have been an "existing or probable hazard" to persons and the environment at the time of detection and should have been graded and repaired accordingly. PHMSA invites comments on other potential criteria for identifying grade 1 leaks subject to immediate repair (for potential inclusion within a final rule in this proceeding), including the utility of adopting a quantified emissions rate criteria for grade 1 leaks or other characteristics indicative of a grave environmental hazard, in addition to criteria proposed above. Comments are especially helpful to PHMSA when they identify a specific quantified emissions rate threshold or other specific characteristics supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

²⁴⁷ Operators may decide to adopt additional grade 1 criteria (or, for that matter, grade 2 criteria) supplementing the baseline criteria PHMSA proposes herein.

²⁴⁸ Several of the grading criteria reference gas readings and are expressed as percent of the lower explosive limit (LEL). The LEL is the minimum required concentration of gas necessary for the gas to ignite when exposed to an ignition source. Percent LEL measures how close measured gas concentration is to reaching a flammable atmosphere. The LEL of natural gas is 5% gas by volume. However, the LELs for other flammable gases vary (*e.g.*, the LEL for hydrogen gas is 4% gas by volume). A reading of 100% or more of LEL indicates that a flammable atmosphere is present, provided there is a sufficient concentration of oxygen present to support combustion and the upper explosive limit (UEL) is not reached. The percent LEL is typically measured during a leak investigation with a combustible gas indicator.

5. Grade 2 Leaks—§ 192.760(c)

PHMSA also proposes to modify the GPTC Guide's characterization of grade 2 leaks to introduce a reference to environmental harms from those leaks: a grade 2 leak would be a leak which presents a probable future hazard to public safety or a significant hazard to the environment. PHMSA intends the proposed characterization of grade 2 leaks to include those leaks that are not as urgent a hazard to either public safety or the environment as a grade 1 leak that it would require immediate and continuous action to eliminate the hazard, but which are significant enough to warrant timely repair.

PHMSA proposes to classify a grade 2 leak as any leak (other than a grade 1 leak) with any of the following characteristics:

- A reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;
- A reading of 100% of the LEL under a street in a wall-to-wall paved area that does not qualify as a grade 1 leak;
- A reading between 20% and 80% of the LEL in a confined space;
- A reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;
- A reading of 80% or greater of the LEL in a gas associated substructure from which gas is not likely to migrate;
- Any reading greater than 0% gas on a transmission or Types A or C gas gathering pipeline that does not qualify as a grade 1 leak;
- Any leak with a leakage rate of 10 CFH or more that does not qualify as a grade 1 leak;
- Any leak of LPG or hydrogen that does not qualify as a grade 1 leak; or
- Any leak that, in the judgment of operator personnel at the scene, is of sufficient magnitude to justify scheduled repair within 6 months or less.

The proposal has important differences from the GPTC Guide that are designed to address gaps in safety and environmental protection. Specifically, PHMSA proposes to delete qualifying language in grade 2 criteria to minimize ambiguity and ensure enforceability of the proposed repair standards. For illustration, in example A.B.2. in Table 3b of the GPTC Guide, any reading of 100% LEL or greater under a street in a wall-to-wall paved area “that has significant gas migration” that is not a grade 1 is considered a grade 2 leak, however what constitutes “significant” gas migration is not defined or straightforward to enforce.

Instead, the NPRM proposes to apply this standard to any such concentration of gas, which is itself hazardous to public safety or the environment, with any migration. Similarly, PHMSA does not propose to condition criteria for grade 2 leaks in substructure on the likelihood that “gas would likely migrate creating a probable future hazard” since a concentration of 80% or more of LEL, near the explosive limit, within a substructure is itself a probable future hazard to public safety. Additionally, PHMSA proposes to add a new criterion for all leaks from LPG systems that do not qualify as a grade 1 leak, consistent with an observation in the GPTC Guide that since LPG is heavier than air and does not dissipate like natural gas, “few [LPG] leaks can safely be classified as Grade 3.”²⁴⁹ Likewise, PHMSA proposes that Grade 2 is the minimum priority grade for leaks of gaseous hydrogen. PHMSA understands these heightened safety requirements (compared to natural gas pipelines) are warranted because hydrogen is itself a flammable gas with a lower explosive limit and lower autoignition temperature than methane. And research summarized by the National Renewable Energy Laboratory indicates that overpressure blast risk in enclosed spaces and increases with the proportion of hydrogen within hydrogen/natural gas blends (particularly for concentrations above 50% hydrogen) and that, for transmission line ruptures, fatal injury risk increases as either proximity to the pipeline or the share of hydrogen in a natural gas blend increases.²⁵⁰

PHMSA also proposes to include a new emissions rate criterion for grade 2 leaks: any leak with an emissions rate equal to or greater than 10 CFH would need to be classified as a grade 2 leak. PHMSA expects this criterion would ensure prioritized repair of such environmentally damaging leaks even if other grade 1 or grade 2 criteria are not met. PHMSA further notes that this proposed 10 CFH criterion is the same criterion used by PG&E's Super Emitter Program, which was based on data showing that methane leaks larger than 10 CFH represented only 2% of all leaks by number but over half of all emission volumes on PG&E's gas distribution

system.²⁵¹ PHMSA's selection of a 10 CFH emissions rate is consistent with the AGA et al. assertion that a significant share of emissions from natural gas pipeline systems can be caused by a relatively small proportion of leaks within each leak category.²⁵² A 2016 analysis by Brandt, et al., of 15,000 emissions measurements from prior studies found that 5% of releases contributed to over half of total emissions volumes.²⁵³ An emissions rate of 10 CFH correlates to emissions of ca. 87,600 ft³ of methane (roughly 1,600 kg of methane) if left unrepaired for a year.²⁵⁴

PHMSA considered alternative approaches to its proposed emissions rate criterion but is concerned about their practicability. PHMSA invites comment on appropriate, alternative grade 2 emissions rate criterion thresholds and calculation methodologies—particularly considering the extent to which emissions from below ground leaks could be incorporated. PHMSA considered an approach employed by the Commonwealth of Massachusetts which categorizes methane leaks from natural gas pipelines as “environmentally significant” grade 3 leaks if they have a barhole reading of 50% gas in air or higher, or a measured leak migration extent of 2,000 square feet or greater.²⁵⁵ In Massachusetts, leaks with a migration extent from 2,000 to 10,000 square feet must be repaired within 2 years and leaks with a migration extent greater than 10,000 square feet must be repaired within 12 months. This method—which measures the extent of below-ground migration as a proxy for the release rate—could be a relatively straightforward means to classify large-volume, below-ground leaks (particularly for gas distribution systems). However, since gas migration can be affected greatly by soil and weather conditions, the 2,000 square feet element of this approach may not be

²⁵¹ Rongere, Francois. “Lessons Learned from the First Year of the Super Emitter Program.” PG&E Nov. 5, 2019. https://www.epa.gov/sites/default/files/2019-12/documents/lessonslearnedfirstyearsuperemitterprogram_francoisrongere.pdf; Lamb, Brian K., et al. “Direct Measurements Show DECREASING Methane Emissions from Natural Gas Local Distribution Systems in the United States.” *Environmental Science & Technology*, vol. 49, no. 8, 2015, pp. 5161–5169., doi:10.1021/es505116p.

²⁵² AGA et al. at 5.

²⁵³ Brandt AR, Heath GA, Cooley D. Methane Leaks from Natural Gas Systems Follow Extreme Distributions. *Environ Sci Technol*. 2016 Nov 15;50(22):12512–12520. Doi: 10.1021/acs.est.6b04303. Epub 2016 Oct 26. PMID: 27740745.

²⁵⁴ The value here was calculated assuming a density of methane of 0.01926 kg/ft³.

²⁵⁵ 220 CMR 114.07(1)(a).

²⁴⁹ See Table 3 C in Appendix G—192–11A of the GPTC Guide.

²⁵⁰ Melania, et al., National Renewable Energy Laboratory Technical Report TP–5600–51995, “Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues” at 16–17 (Mar. 2013), <https://www.nrel.gov/docs/fy13osti/51995.pdf>.

appropriate for a nationwide standard applicable to natural gas distribution, gathering and transmission pipelines across a diversity of operational and environmental conditions, as well as other gases transported in part 192-regulated gas pipelines. Variations in gas migration due to operational and site-specific environmental considerations may then result in missing or over-stating large-volume leaks. PHMSA also considered a relative emissions criterion, such as requiring an operator to repair leaks with an emissions quantity larger than the median leak rate on the operator's system by release rate (estimated with an advanced mobile leak detection technology, high-flow sampler, or equivalent method) or measured gas concentration. While that approach would be comparatively simple to implement, it could result in inconsistent repair requirements across operators as well as perverse consequences: an operator with a well-designed and maintained system with few large-volume leaks would have the same proportion of priority repairs as an operator with poor maintenance practices or significant mileage of leak-prone pipe such that the latter operator could defer repair of potentially large leaks.

PHMSA invites comments on the proposed criteria for identifying grade 2 leaks that constitute a significant hazard to the environment, including the practicability of using a specified emissions rate criterion (and whether 10 CFH is the appropriate emissions rate for grade 2 leaks), for potential inclusion within a final rule in this proceeding. Comments on this question are especially helpful if they identify a specific emissions rate, gas concentration, or other measurement supported by research or operational experience for identifying leaks that should be subject to shorter repair timelines due to their potential environmental impacts over time. PHMSA further invites comments on how quantification of emissions rates are or could be integrated into operator's leak survey, investigation, and management procedures. Finally, PHMSA seeks comments on whether other criteria could be used to identify leaks with significant environmental harm. Comments on these questions are especially helpful to PHMSA when they identify the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA also proposes a minimum grade 2 classification for any leak on a gas transmission or Type A or C gathering pipeline. The GPTC Guide identifies leaks on pipelines operating at 30% SMYS or greater (*i.e.*, most gas transmission lines) in Class 3 or Class 4 locations, other than grade 1 leaks, as grade 2 leaks and assigns a six-month repair requirement. This NPRM proposes to apply this repair timeline to all gas transmission pipelines, and Types A and C gathering pipelines because of the similar design and operating characteristics—and therefore public safety and environmental risk profiles—of those pipelines. In particular, transmission and Type A and Type C gathering lines operate at a high stress level and therefore, as described in section II.D.3, there is a correspondingly higher risk of a rupture if the condition that caused the leak deteriorates further. PHMSA does not propose a similar requirement for offshore gas gathering pipelines because many of those pipelines operate far from the general public and at lower pressures than gas transmission and Type A gathering pipelines such that their public safety and environmental risks are distinguishable.

PHMSA also proposes more timely repair of grade 2 leaks than contemplated by the GPTC Guide, which requires operators to repair such leaks within 12 months of detection. Specifically, PHMSA proposes a default requirement for grade 2 leak repairs to be completed within the earlier of six months of detection, or the repair timeline specified in the operator's procedures or IM plan. The accelerated default repair timeline would better address the significant public safety and environmental risks grade 2 leaks entail. In addition, operators subject to the six-month default repair timeline for grade 2 leaks would be required to re-evaluate each grade 2 leak every 30 days until the leak has been repaired, which is intended to ensure that those leaks do not degrade into a grade 1 leak.

PHMSA proposes shorter repair deadlines for grade 2 leaks that are known on or before the effective date of a subsequent final rule in this proceeding. Further, PHMSA would require these leaks be repaired within one year from the publication date, consistent with the 12-month repair schedule in the GPTC Guide some operator practices may currently reference. Additionally, due to the greater public safety risks of a grade 2 leak from either a gas transmission or Type A gathering pipeline, each within HCAs or densely populated Class 3 or Class 4 locations, PHMSA proposes to

require that these leaks be repaired within 30 days of detection, with an operator making continuous effort to monitor and repair the leak and eliminate the potential hazard if repairs cannot be completed within the prescribed timeline. As previously discussed in section II.C., leaks on gas transmission line pipe are less common than leaks on gas distribution pipeline pipe. However, a leak on a gas transmission or Type A gathering pipeline will likely result in greater release volumes and higher risk of ignition than distribution or Type B gathering lines due to the higher operating pressures and flow volumes typical of transmission and Type A gathering pipelines. The higher operating stress level on gas transmission and Type A gathering pipelines also entail a higher risk of rupture from degradation of leaks over time.

Lastly, PHMSA proposes to require each operator's leak grading and repair procedures to include a methodology for prioritizing grade 2 leak repairs, including criteria for determining leaks that must be repaired within 30 days or less. PHMSA's proposed criteria are based on calendar days rather than the working days under the GPTC Guide, which is consistent with existing guidance in Table 3a of the GPTC Guide. The operator's methodology must also include an analysis of the estimated volume of leakage since detection or the date of the last survey (whichever is earlier), migration of gas emissions, proximity of the leaking gas to buildings and underground structures, the extent of pavement, and soil types and conditions that affect the possibility for hazardous gas migration, such as frost conditions or soil moisture. This approach is consistent with the guidance in the GPTC Guide that certain grade 2 leaks justify repair on an accelerated schedule, and further mandates operators to consider safety and environmental protection when prioritizing repair efforts.

6. Grade 3 Leaks—§ 192.760(d)

PHMSA proposes that any leak that does not meet the criteria for a grade 1 or a grade 2 leak be classified as a grade 3 leak, which would be the lowest priority leak category. PHMSA has provided a non-exhaustive list of grade 3 criteria, including the following: a positive reading of less than 80% LEL in gas-associated substructures from which gas is unlikely to migrate, any positive reading under a street in an area without wall-to-wall pavement where gas is unlikely to migrate to the outside wall of nearby buildings, or a

gas reading less than 20% LEL in a confined space. These examples are derived from the GPTC Guide, with additional clarifying language, “from which gas is unlikely to migrate,” consistent with PHMSA’s understanding of the purpose of the pertinent GPTC Guide example.

The GPTC Guide and most State requirements do not define leak repair deadlines for grade 3 leaks. However, even a small leak can result in significant emissions and harm to the environment and public safety if it is allowed to release indefinitely without repair. Moreover, even small leaks have the potential to progress to more serious integrity incidents and failures, such that a grade 3 leak could develop into a more hazardous condition if ignored indefinitely. PHMSA therefore proposes a 24-month repair deadline for grade 3 leaks detected after the effective date of any final rule in this proceeding; this repair timeline would ensure timely repair of leaks while facilitating operator prioritization of repairs of higher-risk grade 1 and 2 leaks. This proposed repair schedule is 12 months more aggressive than the 36-month deadline adopted by the State of Texas, but consistent with other standards such as the delayed repair permitted for fugitive emissions monitoring in the EPA 40 CFR OOOOa standards for repairs where immediate repair is not feasible.²⁵⁶ On the other hand, some States have more aggressive timelines, suggesting that the proposed timeline remains feasible for repair of buried pipeline facilities. For example, Missouri requires repair of “class 2 leaks”²⁵⁷ within 45 days, unless the pipeline is scheduled for replacement within 1 year.²⁵⁸ The 24-month repair deadline further ensures that all leaks discovered during a leakage survey are repaired prior to the next leakage survey (the longest proposed survey interval is once every 3 years for distribution pipelines outside of business districts, see proposed § 192.723), which would better prevent further growth in the backlog of unrepaired leaks than a 36-month repair deadline. Due to the likely large number of existing grade 3 leaks across the U.S., exemplified by the backlog of 10,000 unrepaired leaks on 11 New York distribution systems described in section II.D.3,²⁵⁹ PHMSA

proposes a repair deadline of 3 years after the publication date of the final rule for grade 3 leaks known to exist on or before the effective date of any final rule. This repair deadline is intended to give operators time to prioritize timely repair of higher-priority, previously-known-to-exist grade 2 leaks, while still ensuring timely repair of grade 3 leaks known to exist at the time a final rule publishes. Additionally, PHMSA proposes to require that each grade 3 leak must be re-evaluated at least once every six months until the repair of the leak is completed. The re-evaluation is designed to assess if the leak or the leak environment has changed in a way that may justify an upgrade to a grade 1 or grade 2 leak.

Lastly, as previously discussed in section II.E of this NPRM certain types of pipe materials cause a disproportionate number of leaks. In particular, pipe and fittings made of cast iron, unprotected steel, wrought iron, and historic plastics with known issues are more likely to leak than coated and protected steel and modern plastics. Replacing these pipelines and other pipelines known to leak can be an effective, long-term solution to systematic leak susceptibility for such pipelines. For example, in AGA’s presentation at PHMSA’s May 2021 public meeting on methane leak detection and repair, they noted that operators cast iron and bare steel distribution pipelines accounted for approximately 75 percent of reported leak repairs.²⁶⁰ These replacement programs multiply benefits by eliminating both existing and future leaks. To accommodate pipe replacement programs, particularly on leak prone facilities, PHMSA proposes to allow that a grade 3 leak may be monitored rather than repaired if the leaking pipeline is scheduled for replacement or abandonment, and is in fact replaced or abandoned, within five years from the date of detection of the leak. This five-year timeline is intended to accommodate the time necessary for planning, permitting, engineering, design, and construction of pipeline replacement projects. This proposed timeline is consistent with PHMSA’s Natural Gas Distribution Infrastructure Safety and Modernization Grants program, which permits applicants to elect a period of performance of up to 5 years for pipe replacement projects.²⁶¹

Due to the heightened potential hazards to public safety and the environmental, PHMSA does not propose a similar allowance for grade 1 and grade 2 leaks.

PHMSA seeks comments on the proposed repair timelines for grade 3 leaks (for potential inclusion within a final rule in this proceeding), including whether shorter repair timelines would be appropriate for grade 3 leaks existing as of publication of a final rule, or for grade 3 leaks eliminated by pipeline replacement. Comments on these questions are especially helpful when they provide specific suggestions supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

7. Post-Repair Inspection—§ 192.760(e)

PHMSA proposes to specify that a leak repair may only be classified as complete if the operator obtains during a post-repair inspection a gas concentration reading of 0% gas by volume at the leak location. The equipment used in leak investigations, including this post-repair inspection, must meet the proposed 5 ppm sensitivity standards in § 192.763(a)(1)(ii). This proposed inspection requirement ensures that the repair was effective and provides a definite, final repair date for operator records. For leaks that are eliminated by routine maintenance—such as cleaning, lubrication, or adjustment—a post-repair inspection would not be required for any leaks from aboveground facilities or for grade 3 leaks from other facilities.

PHMSA proposes that an inspection must occur between 14 and 30 days after the date of the repair. PHMSA intends the minimum interval before the first repair inspection to help ensure that the inspection accurately reflects the condition of the repair, since repairs may have a 0% reading at the moment of repair, but gas may leak over time from an incomplete repair or the repair may fail in a 14-day period. PHMSA is proposing a 30-day maximum to align with its proposed 30-day monitoring requirement for grade 2 leaks. If the operator is unable to achieve a 0% reading and determines that a grade 1 or 2 condition exists, PHMSA proposes that the operator must take immediate and continuous action to re-evaluate and remediate the repair so as to

²⁵⁶ 40 CFR 60.5397a(h)(3).

²⁵⁷ This term is unrelated to class 2 locations set forth in 49 CFR 192.5.

²⁵⁸ 20 [Missouri] Code of State Regulations 4240–40.030(14)(C)(2).

²⁵⁹ State of New York Department of Public Service, Case 21–G–0165, “2020 Pipeline Safety Performance Measures Report” at Appendix K (June 17, 2021).

²⁶⁰ Sames, Christina. “Pipeline Leak Detection, Leak Repair, and Methane Emissions.” AGA. May 5, 2021. <https://primis.phmsa.dot.gov/meetings/FilGet.mtg?fil=1139>.

²⁶¹ See PHMSA, “Frequently Asked Questions: FY 2022 Natural Gas Distribution Infrastructure Safety and Modernization Grant Notice of Funding

Opportunity (NOFO)” (July 29, 2022). FAQ 67 at page 16. <https://www.phmsa.dot.gov/grants/pipeline/ngdism-nofo-faqs>.

eliminate the leak. This proposed repair timeline could accelerate the repair of some grade 2 leaks. An accelerated timeline may be warranted because an incomplete or failed first attempt at leak repair could inhibit subsequent efforts to properly repair the leak. The proposed rule requires that if the post-repair inspection indicates a gas reading of greater than 0% gas and a grade 1 or grade 2 condition does not exist, the operator must remediate and re-inspect the repair every 30 days until it obtains a gas concentration reading of 0%. In this situation, remediation of a repair of a grade 3 leak would be completed before the initial repair deadline of 24 months from the date of initial detection. If a grade 3 condition exists during a post-repair inspection for a leak that was originally a grade 1 or grade 2 leak at the time of detection, the operator may consider downgrading the leak under proposed § 192.760(g), in which case the repair deadline is determined by the repair deadline proposed under § 192.760(h).

8. Upgrading and Downgrading—§ 192.760 (f) and (g)

PHMSA proposes to establish requirements for when and how a leak may be upgraded to a higher-priority grade or downgraded to a lower-priority grade. Section 192.760(f) would require that if an operator receives information that a higher-priority grade condition exists on a previously graded leak, the operator must upgrade the leak to that new grade. For a leak that is upgraded, the repair deadline is the earlier of the remaining repair deadline for the original grade, or the repair deadline under the new leak grade measured from the date the operator receives the information that a higher-priority grade condition exists. This proposed approach would provide certainty regarding the repair deadline for an upgraded leak, while avoiding the perverse consequence that upgrading a leak would allow a more permissive repair schedule.

PHMSA also proposes to allow downgrading a leak grade only if a repair has been attempted. This approach would allow downgrading a leak only if the operator performed a temporary repair or attempted a permanent leak repair but did not obtain a 0% gas reading during the post-repair inspection under proposed § 192.760(e). This would prevent practices such as downgrading a leak after venting until gas concentration falls below a grade 1 or grade 2 criteria, without an effort to repair the leak itself. If a leak is downgraded, PHMSA proposes the time period for repair would be the

remaining time allowed for repair for the downgraded leak measured from the time the leak was first detected—an approach PHMSA expects would incentivize timely completion of downgraded repairs and prevent extension of repair timelines through pretextual attempts at permanent repair.

9. Extension of leak repair—§ 192.760(h)

PHMSA proposes to allow an extension of the repair deadline requirements for individual leaks on a case-by-case basis. Any extension requires notification to, and review by, PHMSA pursuant to the procedures in § 192.18. Leak repair extensions under § 192.760(h) may be requested only if (1) the leak repair pursuant to an alternative schedule would not result in increased public safety risk, and (2) the operator can demonstrate that the prescribed repair schedule is impracticable, an alternative repair schedule is necessary for safety, or remediation within the specified time frame would result in the release of more gas to the environment than would otherwise occur if the leak were allowed to continue. For example, an alternative repair schedule may be warranted if remediation within the timeframe proposed in this NPRM would result in the release of more gas to the environment from blowdown—delayed repair could minimize emissions by coordinating blowdowns with other maintenance activity, while offering the safety benefit of fewer emissions that could ignite. PHMSA proposes to limit the extensions to grade 3 leaks, which inherently pose lower risks to public safety and the environment than grades 1 and 2 leaks. The notification to PHMSA would need to include a description of the leak, the leaking pipeline, the leak environment, any proposed monitoring and extended repair schedule, the justification for an extended repair schedule, and proposed emissions mitigation methods.

10. Recordkeeping—§ 192.760(i)

PHMSA proposes certain recordkeeping requirements for leak detection, investigation, grading and repair activity. Section 192.760(i) would describe recordkeeping requirements associated with leak grading and repair; PHMSA proposes that records documenting the complete history of investigation and grading of each leak prior to completion of the repair would need to be retained until five years after the date of the final post-repair inspection performed under proposed paragraph § 192.760(e). Pertinent records would include documentation of grading monitoring, inspections,

upgrades, and downgrades. PHMSA also proposes that records associated with the detection, remediation, and repair of each leak must be maintained for the life of the pipeline. This permanent recordkeeping would apply to both piping and non-piping portions of the pipeline. Should leak detection occur during a patrol, survey, inspection, or test, the pertinent portion of documentation for that patrol, survey, inspection, or test would need to be retained pursuant to proposed § 192.760(i). These proposed documentation requirements would support periodic evaluation and improvement of their ALDPs pursuant to proposed § 192.763(a)(4) as well as regulatory oversight activity by PHMSA and its State partners.

D. Qualification of Leakage Survey, Investigation, and Repair Personnel—§ 192.769

Proposed § 192.769 would require that operator personnel engaged in leakage surveys, and the investigation and repair of leaks discovered on each of gas transmission, distribution, offshore gathering, and Type A regulated onshore gathering²⁶² pipelines are subject to the personnel qualification requirements at part 192 in performing those activities. PHMSA proposes to clarify that leakage surveys, investigation, and repair activities are “covered tasks” under part 192, subpart N and therefore covered by operator qualification requirements in that subpart. These operations and maintenance functions are critical to ensuring the proper operation and integrity of gas pipelines, and therefore meet the criteria for the four-part test for defining covered tasks in § 192.801(b) (tasks that are performed on a pipeline facility; are operations or maintenance tasks; are required by part 192; and affect the operation or integrity of the pipeline). Therefore, the proposed revision would help ensure baseline regulatory requirements for personnel qualification are met when performing those activities.

PHMSA understands that the proposed personnel qualification requirements discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. PHMSA understands

²⁶² PHMSA regulations at § 192.9(c) allow operators of Type A gas gathering pipeline to employ less comprehensive programs in satisfying subpart N personnel qualification requirements than employed by certain other part 192-regulated gas pipelines. PHMSA is not proposing a different approach for personnel qualifications with respect to personnel conducting leakage surveys and investigation and repair of leaks on Type A gas gathering pipelines.

that some affected operators may already have adopted (either voluntarily or in response to State or Federal requirements) compliant training and personnel practices, or would be able to adapt existing practices with minimal effort—particularly as ensuring personnel employed in conducting leakage surveys, inspection, and repair activities is a practice that reasonably prudent operators would adopt in ordinary course to protect public safety and the environment from release of pressurized (natural, flammable, corrosive, and toxic) gases transported in their pipelines and minimize loss of commercially valuable commodity. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop and provide the requisite training for their personnel (or otherwise obtain access to qualified personnel) and manage any related compliance costs. PHMSA seeks comments on whether, within a final rule in this proceeding, it would be appropriate to apply the proposed operator qualification requirements in § 192.769 to Type B and Type C regulated onshore gas gathering lines or UNGSFs, which are not currently required to comply with subpart N. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that approach, including whether that approach would be technically feasible, cost-effective, and practicable. For gas gathering pipelines, this could entail subjecting Type B and applicable Type C gathering pipelines to simplified subpart N requirements similar to Type A lines in Class 1 locations and could either apply generally to all covered tasks, or only for leak detection, grading, and repair activities.

E. Reporting and National Pipeline Mapping System—§§ 191.3, 191.9, 191.11, 191.17, 191.19, 191.23, and 191.29

PHMSA proposes new and revised reporting requirements to collect more data on pipeline leaks and other emissions. The most significant

proposed revisions would create a large-volume gas release report to supplement existing incident reporting requirements. As is the case for incident reports, this requirement would apply to any gas pipeline facility covered under part 191, including jurisdictional storage and part 193 LNG facilities. Additionally, PHMSA proposes to revise the gas transmission, offshore gathering, and Types A, B, and C gathering, and distribution annual report forms to include each of (1) estimated aggregate emissions from all leaks existing on the system within the calendar year by grade (including emissions within the calendar year from leaks discovered in prior years), (2) other methane emissions by source category, and (3) the number of leaks detected and repaired by grade. PHMSA solicits comments on the potential utility of requiring operators to report more granular leak data, such as individual leak location, individual leak emissions, or individual leak repair timing, in addition to the information described above. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

Existing § 191.3 defines an incident as a release from a gas pipeline facility that results in death or serious injury, property damage of \$122,000²⁶³ or more in calendar year 2021, or an unintentional release of 3 MMCF or more of gas. While incident reports provide valuable information on major emissions events with critical safety consequences, existing incident reporting criteria and the exclusion of intentional releases from reporting requirements means the current reporting scheme does not capture data on many significant emissions events.

PHMSA therefore proposes at § 191.19 to require a new report for intentional and unintentional releases with a volume of 1 MMCF or greater, excluding certain events that had been reported as incidents under §§ 191.9 or 191.15. For illustration, routine leaks with an emissions rate of 10 CFH consistent with the proposed grade 2 emissions criteria at § 192.760, would not be reported individually under this section if they are repaired within the proposed repair schedule (note that a count of all leaks would be reported on annual reports), but larger leaks exceeding 100 kg/hr. “super-emitter” criteria contemplated by the EPA in their

December 6, 2022 supplemental notice of proposed rulemaking²⁶⁴ would be reported if they were not promptly repaired such that their aggregate emissions were below the 1 MMCF threshold. Blowdowns of high-pressure lines without mitigation measures such as those proposed in § 192.770 may also meet the 1 MMCF threshold depending on the pressure and volume of the blowdown segment. Operators would be required to submit a report within 30 days from the date that a release known at detection to be 1 MMCF or more was detected, or 30 days from the date that a previously detected release became reportable. If the time the leak started is unknown, operators should base the calculation based on estimated release volume from the date of the most recent leakage survey. PHMSA proposes an exception from § 191.23 safety-related condition reporting requirements for events that are reported as large-volume gas releases. This proposed exception for large-volume incident reports would be consistent with the existing exception at § 191.23(b) for events reported as incidents.

These new, large-volume gas release reports would provide valuable information on the primary sources and causes of vented emissions and the causes of large-volume leaks that do not qualify as incidents, addressing information gaps in the current incident reporting requirements. First, information on vented emissions is not currently collected on incident or annual report forms. The new report would provide PHMSA and other interested stakeholders information on the causes, consequences, and frequency of intentional, large-volume, vented emissions to provide both regulators and operators the information necessary to prevent reoccurrence. That information would be also particularly useful for PHMSA and State regulatory authorities in ensuring operator compliance with the self-executing mandate within section 114 of the PIPES Act of 2020 for operators to update their inspection and maintenance procedures to provide for minimization of releases of gas from their pipeline facilities. Second, PHMSA's proposed 1 MMCF threshold for the new large-volume gas release report is significantly lower than the 3 MMCF threshold required under the current incident reporting regulations, allowing PHMSA to collect detailed

²⁶⁴ EPA, “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” 87 FR 74702, 74707 (Dec. 6, 2022).

²⁶³ Adjusted for inflation on an annual basis.

cause and consequence information on large-volume, intentional and unintentional releases that may not be collected on incident reports. PHMSA solicits comment on whether alternative reporting thresholds for either large volume gas releases or incidents, including thresholds below 1 MMCF, would provide higher-quality information than PHMSA's proposed 1 MMCF threshold. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

PHMSA proposes to include the above information on a new report rather than by revising the incident definition at § 191.3 to collect focused information on fugitive and vented emissions that do not satisfy incident reporting criteria. Operators of all gas pipeline facilities would remain required to submit incident reports if unintentional releases reported under this new requirement subsequently satisfy incident reporting criteria. Operators who have already submitted an incident report would not need to file a large-volume gas release report under § 191.19 for the same event so long as the release volume in the incident report is within 10 percent of the total release volume on cessation of the release. PHMSA intends for the large-volume gas release reporting requirement to extend to Type R gas gathering pipelines to inform PHMSA's consideration of whether fugitive and vented emissions from those pipeline facilities warrant extension of part 192 requirements.

PHMSA proposes to clarify what is considered property damage for the purpose of determining whether a release is reportable as an incident pursuant to §§ 191.9 or 191.15. Specifically, PHMSA proposes revision of the definition of "incident" at § 191.3 to exclude, when calculating estimated property damage, costs associated with each of obtaining permits and removal or replacement of infrastructure undamaged by the event (*e.g.*, pavement needed for access and repair activity) in connection with an event. This change would respond to NAPS Resolution 2021–01, "A Resolution Seeking a Modification of PHMSA's Instructions for Incident Reporting for Gas Distribution, Gas Transmission, and Gas Gathering Systems,"²⁶⁵ which concerns how to classify overall secondary damage beyond the primary damage

from an incident. Operators would still report these costs as incident consequences on the applicable incident report forms; however, they should not be included in the calculation of property damage for determining whether a release is reportable as an incident.

PHMSA also proposes changes to the gas distribution, transmission, offshore gathering, and regulated onshore gas gathering annual reports required by §§ 191.11 and 191.17, consistent with other proposed changes regarding leak grading and repair on those facilities and to collect information on estimated total emissions from each of (1) leaks existing on the operator's system during the calendar year by grade and (2), other emissions by source category. The source categories generally mirror the categories in the GHGI, as summarized in section II.C.2. While existing annual report forms include limited data on leaks repaired in the preceding year, they lack other data—including the number and grade of leaks detected in the preceding year, the grade of leaks repaired in the preceding year, and estimated release volumes from those leaks—important for PHMSA and State regulators to understand the frequency of leaks, the significance for public safety and the environment from those leaks, and adequacy of operator leak detection and repair programs. PHMSA therefore proposes to revise the annual report forms for operators of gas distribution, offshore gathering, regulated onshore gathering, and transmission pipeline facilities to collect data on each of the following: the number of leaks detected and repaired by grade (see proposed § 192.760); the estimated aggregate emissions from all existing leaks (whether detected in the reporting year or not) by grade, and estimated emissions from other sources by source categories. PHMSA further proposes that, because this NPRM does not provide for leak grading requirements for LNG facilities, operators of those facilities would need to report data on each of the number of methane leaks detected and repaired during the annual reporting period pursuant to proposed § 193.2624, the number of unrepaired leaks at the end of the annual reporting period, and estimated fugitive methane emissions (each by EPA GHGRP source category) from all methane leaks identified pursuant to proposed § 193.2624. PHMSA is not proposing similar enhanced annual reporting requirements for Type R gathering pipelines because those facilities would not be subject to the leak grading and

repair requirements at § 192.760. However, PHMSA sees value in reviewing the results of recently-adopted incident and annual reporting requirements for those pipelines under the Gas Gathering Final Rule, as well as the large-volume gas release reporting requirements proposed herein, to inform a path forward regarding expanding annual reporting requirements for Type R pipelines.

For emissions reporting, PHMSA proposes operators provide aggregate emissions estimate for leaks by grade. PHMSA also proposes to collect estimated annual emissions by source category, which includes both leaks, incidents, and vented emissions. The source categories generally mirror the categories in the GHGI and as summarized in section II.C.2. This approach would ensure that both EPA and PHMSA have high-quality leak emissions data to support their distinguishable, but mutually-reinforcing, regulatory responsibilities. For PHMSA aggregate emissions data provided on a per-leak grade basis would be particularly useful in informing future decision-making calibrating part 192 safety requirements based on an evolving understanding of the safety and environmental hazards posed by different grades of leaks. Similarly, information on other emissions would better inform Federal, State, and operator efforts to minimize avoidable vented emissions, which is required under section 114 of the PIPES Act of 2020. PHMSA would require that, in developing aggregate emissions estimates, operators would employ direct measurement and/or top-down methodologies along the lines of those discussed in section III.C.2 above.²⁶⁶

PHMSA also proposes to require operators to submit geospatial data about offshore gas gathering and Type A, Type B, and Type C gathering pipelines to the NPMS. The NPMS is a geographic information system (GIS) that contains the locations and related attribute data for a variety of pipeline facilities. The NPMS was established via a self-executing requirement codified in 49 U.S.C. 60132; while that statutory mandate excluded distribution and gathering lines, PHMSA has authority elsewhere in the Federal Pipeline Safety Laws at 49 U.S.C. 60117(c) to collect safety data for gathering pipelines to inform whether and how to provide

²⁶⁶ PHMSA would also consider estimated emissions methodologies employed by EPA-qualified third-party notifiers in reporting leaks under EPA's super-emitter response program proposals within its supplemental notice of proposed rulemaking issued under RIN 2060–AV16. See EPA SNPRM.

²⁶⁵ <http://www.napsr.org/resolutions.html>.

regulatory oversight of those facilities. Pipeline safety stakeholders—including journalists, operators, emergency responders, excavators, elected officials, public interest advocates, and PHMSA and State regulators—use the NPMS to obtain important pipeline-safety related information, including the locations of pipelines and related infrastructure, the names and contact information of pipeline operators, and other attributes of pipelines such as commodities transported and diameter.²⁶⁷ In particular, access to gathering pipeline geospatial data on NPMS would reinforce damage prevention programs required under § 192.614. Emergency responders often use the NPMS to identify pipelines in the vicinity of reported leaks and contact relevant operators. Emergency responders and pipeline operators also use the NPMS while conducting drills and exercises to support operators' emergency response plans. The requirement to submit data to the NPMS would also reinforce operators' efforts in developing and maintaining adequate maps and records of their systems.

In addition to the benefits detailed above, PHMSA expects that its proposed amendments to NPMS requirements may also improve operators' leak detection programs. First, it would ensure that operators know the location of their pipelines; accurate location information can improve the accuracy of leakage surveys and patrols for buried pipelines, especially for leakage surveys performed with handheld equipment. Second, if a pipeline is in the NPMS, it is easier for third parties such as other operators, researchers, or the public to report leaks, ruptures, and other unsafe conditions to the operator. Public interest groups and aerial survey technology providers have noted that they have had difficulty identifying the operator of a facility where a leak indication was detected. PHMSA solicits comment on whether, within a final rule in this proceeding, it would be appropriate to require NPMS participation for Type R gathering pipelines not regulated under part 192. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

While operators may engage third parties as part of their efforts to comply with the requirements proposed herein

(for example, by contracting with vendors of technologies such as those discussed in section II.D.4 above), PHMSA has not proposed in this NPRM any formal role for third parties in the detection or reporting of leaks or intentional emissions. PHMSA invites comment on whether PHMSA should revise § 192.605 to address operators' procedures for responding to third-party reports of gas releases or otherwise incorporate elements from or leverage EPA's super-emitter response program proposed in the EPA SNPRM for third party leak reporting²⁶⁸ as a backstop to support the reporting requirements proposed herein (for potential inclusion within a final rule in this proceeding), including whether data from such third party leak reporting should be included in operator reports to PHMSA (including aggregate emissions estimates by grade). PHMSA further invites comment on whether to facilitate third party reporting of operator non-compliance with the proposed requirements in this rulemaking (or any other provision of PHMSA regulations) to the attention of PHMSA enforcement personnel or State partners. Comments on these questions are especially helpful to PHMSA when they identify specific proposals supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA understands that the proposed enhanced reporting and NPMS requirements discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. The contents of PHMSA's proposed new large-volume gas release report will resemble longstanding incident reporting requirements applicable to unintentional releases from part 192-regulated gas pipelines. Meanwhile, PHMSA's proposed enhanced annual reporting requirements for leak and repair activity would largely consist of reporting of information obtained from operator efforts in complying with the enhanced leak detection and repair requirements proposed elsewhere in this NPRM. Meanwhile, PHMSA's proposal to extend NPMS requirements to all part 192-regulated gas gathering lines would merely require those operators to submit information (including the precise location of their pipelines, the commodity transported, etc.) that reasonably prudent operators would maintain in ordinary course to

protect public safety and the environment from the pressurized (natural flammable, corrosive, or toxic) gases transported in their pipelines. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments to part 191 reporting requirements will be a cost-effective approach to obtaining enhanced data on intentional and unintentional releases of methane and other part 192-regulated gases necessary to inform PHMSA enforcement, policy development, and incident avoidance and response efforts. Lastly, the NPRM's proposed compliance timelines with those proposed reporting requirements—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to design and implement requisite protocols and manage any related compliance costs.

F. Mitigating Vented and Other Emissions From Gas Pipeline Facilities—§§ 192.9, 192.12, 192.605, 192.770, 193.2503, 193.2523 and 193.2605

In light of the significant methane emissions associated with blowdowns and other vented gas emissions from PHMSA-jurisdictional gas pipeline facilities, and to facilitate operator implementation of the self-executing mandate in section 114 of the PIPES Act of 2020, PHMSA proposes to incorporate that statutory language within the Pipeline Safety Regulations.²⁶⁹ Specifically, PHMSA proposes to incorporate an explicit requirement to eliminate leaks of all flammable, toxic, or corrosive gases, as well as minimize releases of natural gas, within provisions prescribing the content of operating, emergency, and maintenance manuals for gas transmission, distribution, Type A gathering and offshore gathering pipelines (§ 192.605 via current § 192.9), Types B and C gathering pipelines (§ 192.605 via a revised § 192.9(d) and (e)), UNGSFs (§ 191.12(c)), and part 193 LNG facilities (§§ 193.2503 and 193.2605). The proposed broad-based incorporation of the PIPES Act of 2020 section 114 mandate would promote operator compliance efforts by aligning

²⁶⁷ PHMSA acknowledges that stakeholders do not have uniform access to information within NPMS.

²⁶⁸ See EPA SNPRM, 87 FR at 74746.

²⁶⁹ PHMSA has, pursuant to section 114 of the PIPES Act of 2020, initiated a study on the best available technology or practices to reduce methane emissions associated with design, construction, operations, and maintenance of pipeline facilities, and will initiate a rulemaking based on the results of that study.

PHMSA's regulatory requirements with the statutory mandate and helping to ensure that leak elimination and natural gas release mitigation inform the spectrum of operator activities. The proposed regulatory text would reinforce other operator obligations (including, but not limited to, repair criteria and IM requirements) throughout PHMSA regulations that improve safety, environmental protection, and U.S. competitiveness.

PHMSA proposes that operators of gas transmission, offshore gathering, Type A gathering, and part 193 LNG facilities would have to adopt specific requirements for minimizing the release of gas during non-emergency blowdowns, LNG tank boil-offs, and other vented emissions events. According to GHGI data described in section II.C of this NPRM, approximately one-fourth of annual methane emissions from U.S. natural gas transmission pipelines are from vented emissions, including blowdowns. For LNG facilities, blowdowns represented around 48% of methane emissions, and as much as 80% of methane emissions from storage appurtenant to LNG facilities. PHMSA also notes that boil-offs of LNG storage tanks at part 193 LNG facilities to accommodate maintenance activity are similar in function to blowdowns on part 192 pipeline facilities—and similarly can be significant contributors of methane emissions if released to atmosphere.²⁷⁰ Mitigation of non-emergency vented emissions as an important opportunity for reducing methane emissions. The EPA Natural Gas STAR program listed blowdown volume mitigation among several cost-effective and recommended technologies for reducing methane emissions from operations, maintenance, and construction.²⁷¹ Additionally, the “Best Management Practice” commitment option for EPA's voluntary Methane Challenge program identifies various

methods of reducing or eliminating blowdown emissions volumes similar to those proposed in this NPRM.²⁷² The PST has identified similar mitigation options in public comments to rulemaking actions dating from 2016, and INGAA included minimizing blowdown volume in a list of commitments that member companies are making to address methane emissions.²⁷³

PHMSA therefore proposes to amend its regulations pertaining to each of gas transmission, regulated offshore gathering, and Type A gathering pipelines (§ 192.770) and part 193 LNG facilities (§ 193.2523) to identify a menu of proven options—many of them featuring prominently in the voluntary initiatives described in the preceding paragraph that operators must choose from to mitigate methane releases during blowdowns, tank boil-offs, and other vented emissions.

Proposed §§ 192.770(a) and 193.2523(a) include an option to install and use valves or control fittings to reduce the volume of gas that must be removed from pipeline facility segments. Instead of blowing down a pipeline facility between mainline block valves or compressor stations, the operator would isolate a shorter segment of pipe, resulting in lower release volumes. In addition to the emissions abatement benefits from isolating shorter segments for maintenance tasks, this approach can have operational benefits from reducing or eliminating downtime by bypassing the shut-in segment. A second proposed method is routing vented gas to a flare stack to be ignited or to other equipment to be collected for later use. Burning gas rather than releasing it into the atmosphere significantly reduces the climate change impacts of vented emissions by converting methane gas to carbon dioxide and water via combustion. Under favorable conditions a well-designed and maintained flare stack can combust gas with almost 100% efficiency, however leaks and unlit or incomplete flaring (due to poor maintenance, design, or operation practices) can reduce the methane reduction efficiency on a field-level basis to approximately 90%.²⁷⁴ Leaks

and releases from flaring equipment would be subject to the proposed amendments in this NPRM as components of a “pipeline” as defined in parts 191 and 192. Routing or recovering gas for use as a fuel source is similar in principle to flaring. The third, fourth, and fifth approaches identified in proposed §§ 192.770(a) and 193.2523 involve reducing pressure (or, in the case of LNG tank boil-off, LNG volumes) of a pipeline segment prior to venting, thereby reducing total emissions volume. In the third approach, an operator would isolate the pipeline segment upstream of the vented segment and use the downstream compressor station to reduce the pressure of the affected segment. The fourth approach is similar except instead of the compressor station, an operator would use a mobile compressor unit to reduce the pressure of the segment by compressing gas, or diverting LNG, into adjacent facilities or a storage vessel. The fifth approach—transferring gas or LNG to a lower-pressure pipeline segment—is like the fourth, except it may be performed without compression in certain circumstances. PHMSA seeks comment on whether it is appropriate to specify a minimum pressure or pressure reduction in the vented segment for pressure reduction methods and any other mitigation measures operators should consider. Lastly, PHMSA proposes that operators be able to employ alternative approaches not listed in §§ 192.770(a) and 193.2523(a) for release volume mitigation, provided that the operator can demonstrate that a proposed approach reduces the volume of released gas by at least 50% compared with taking no mitigative action. This is consistent with the approach used in the EPA's Methane Challenge²⁷⁵ program and would provide operators with flexibility to employ techniques and technologies appropriate for the unique operating and environmental conditions of their facilities and would accommodate future advancements in release mitigation technologies and practices. PHMSA invites comment on whether, for any (or all) of the release volume mitigation approaches proposed in §§ 192.770(a)(1) through (5) and 193.2523(a)(1) through (3), operators should be required to demonstrate that a particular approach reduces the

²⁷⁰ Vented and other releases of cryogenic LNG to the atmosphere also present unique safety hazards and can cause flammable vapor clouds, jet or pool fires in the presence of an ignition source, or a sudden and explosive phase change if LNG encounters a warm surface such as water. When spilled directly onto water, LNG can rapidly convert from liquid to gaseous phase, releasing enough energy to cause a physical explosion without any combustion or chemical reaction. See World Bank Group, Environmental, Health, and Safety Guidelines: Liquefied Natural Gas Facilities (2017). In addition, vented releases of unprocessed gas results in the release of VOCs and HAPs that entail distinguishable environmental and public safety harms.

²⁷¹ See PRO Fact Sheets Nos. 401, <https://www.epa.gov/sites/default/files/2016-06/documents/injectblowdowngas.pdf>.

²⁷² EPA, “Natural Gas STAR Methane Challenge Program: BPM Commitment Option Technical Document” (May 2022), https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf (last accessed Dec. 20, 2022).

²⁷³ <https://www.ingaa.org/File.aspx?id=38582>; <https://www.regulations.gov/comment/PHMSA-2011-0023-0272>.

²⁷⁴ Duren, Riley and Deborah Gordon. “Tackling unlit and inefficient gas flaring.” *Science*. Vol. 337

Issue 6614. (2022): 1486–1487. <https://www.science.org/doi/full/10.1126/science.ade2315>.

²⁷⁵ See EPA, “Methane Challenge Program BMP Commitment Option Technical Document” at pg. 21 (May 2022), https://www.epa.gov/system/files/documents/2022-05/MC_BMP_TechnicalDocument_2022-05.pdf (last accessed March 16, 2023).

volume of released gas by at least 50% compared with taking no action (consistent with the EPA's Methane Challenge program) (for potential inclusion within a final rule in this proceeding). PHMSA further invites comment on whether a different minimum percentage reduction (higher or lower than 50%) would instead be more appropriate for any (or all) of the release volume mitigation approaches proposed in §§ 192.770(a) and 193.2523(a) (for potential inclusion within a final rule in this proceeding). Comments on each of these questions are especially helpful when they are supported by research or operational experience, along with the potential safety and environmental benefits and potential costs of a particular approach (including whether that approach would be technically feasible, cost-effective, and practicable).

PHMSA further proposes in §§ 192.770(c) and 193.2523(c) that those operators develop documentation describing the suite of actions undertaken—including, but not limited to, their choice from among the blowdown mitigation method(s) identified in either §§ 192.770(a) or 193.2523(a)—to minimize vented emissions from their systems. PHMSA does not propose to require mitigation for emergency blowdowns pursuant to an emergency plan under §§ 192.615(a)(3) or 193.2509 so as to ensure that emissions mitigation will not come at the expense of public safety and other environmental resources; however, PHMSA proposes at §§ 192.770(b) and 193.2523(b) to require that operators document such events, including the justification for not taking mitigative action.²⁷⁶

PHMSA understands that its proposed requirements for minimizing vented and other releases from certain gas pipeline facilities discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. PHMSA understands that some affected operators may already have adopted protocols for minimizing vented emissions and eliminating leaks from their facilities either voluntarily (e.g., to minimize loss of a commercially valuable—and hazardous—commodity) or in response to State or Federal requirements (including, but not limited to, the self-executing mandate in section 114 of the PIPES Act of 2020). The NPRM reinforces those efforts by codifying that self-executing statutory mandate in the

pipeline safety regulations. Similarly, PHMSA's proposals accommodate a variety of compliance strategies; the text of pertinent regulatory provisions contains a non-exclusive menu of compliant approaches from which operators can choose as appropriate for their needs and their facilities' operational characteristics and environment. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop and implement compliance protocols and manage any related compliance costs.

Although the NPRM does not include a similar prescribed menu of required blowdown emissions mitigation approaches for gas distribution or Types B and C gathering pipelines due to the comparatively smaller blowdown volumes of some of those systems, PHMSA seeks comment on whether, within a final rule in this proceeding, it would be appropriate to require use of some of the methods for mitigating transmission pipeline and LNG facility blowdown emissions proposed herein for use on gas distribution or Types B and C gathering pipelines. PHMSA also seeks comment on whether it is appropriate to restrict the use of flaring to instances where other mitigation measures are impracticable. Comments on these questions are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

The proposals described in this section are intended to codify section 114(a) and (b) of the PIPES Act of 2020 and address a subset of operations and maintenance-related emissions sources. PHMSA has a separate Congressional mandate under section 114(d) of the PIPES Act of 2020 to promulgate pipeline design, operations, and maintenance requirements to “prevent or minimize, without compromising pipeline safety, the release of natural gas” in connection with intentional operator releases. PHMSA will address this mandate in a future rulemaking

action following the completion of a report to Congress discussing the best available technologies, practices, and designs to prevent or minimize such releases (per section 114(d)(1) of the PIPES Act of 2020).²⁷⁷ Specifically, the report must evaluate pipeline facility designs that mitigate the need to intentionally vent natural gas (without compromising pipeline safety) as well as the best available technologies or practices to prevent or minimize the release of natural gas when making planned repairs, replacements, or maintenance to a pipeline facility and when the operator intentionally vents or releases natural gas, including blowdowns. As of the date of issuance of this final rule, PHMSA is in the process of developing the best available technologies and practices report referenced in section 114(d)(1).

G. Design, Configuration, and Maintenance of Pressure Relief Devices—§§ 192.9, 192.199 and 192.773

PHMSA proposes to minimize emissions caused by malfunctioning pressure relief devices and other unnecessary releases from poorly designed or configured pressure relief devices. A pressure relief device vents gas to the atmosphere (or to a flare) when the pressure in the system satisfies either design or configuration actuation criteria,²⁷⁸ to protect the integrity of the facility from an overpressure condition. A pressure relief device may malfunction by not releasing gas as required by those criteria, risking an overpressure condition that can induce a loss of system integrity and release of gas to atmosphere. Alternatively, a pressure relief may malfunction by operating before those criteria have been satisfied, which results in unnecessary releases of gas to the atmosphere. Similarly, a pressure relief device with design or configuration actuation criteria more conservative than necessary to provide

²⁷⁷ Section 114(d)(2) of the PIPES Act of 2020 requires the Secretary to update the Pipeline Safety Regulations that the Secretary has determined are necessary to protect the environment without compromising safety within 180 days after submitting the section 114(d)(1) report.

²⁷⁸ PHMSA here draws a distinction between design actuation criteria set by a device manufacturer (which generally cannot be changed by an operator) and configuration actuation criteria (which in some cases could be changed by an operator post-manufacture and installation). PHMSA further notes that by “actuation criteria” it means the suite of setpoints (e.g., pressure) and other conditions (e.g., programmable logic) that must be satisfied for a pressure relief device to actuate and cease actuation. For example, actuation criteria may consist of a pressure setpoint at which a pressure relief valve may open, as well as a setpoint for that same valve to close.

²⁷⁶ Note that a blowdown that is not mitigated may also be reportable under the proposed large-volume gas release report.

adequate margin to an overpressure condition can also result in unnecessary gas releases. Additionally, a pressure relief device whose design or materials are ill-suited for use in a pipeline facility's particular operating and environmental conditions may fail or leak.

PHMSA often receives reports of major releases from pressure relief device failures: since 2010, operators have submitted 112 incident reports for releases from pressure relief devices on gas transmission and regulated gas gathering pipelines from 2010 through the end of 2022, reporting an average release volume of 12.5 MMCF from each event. The largest relief device failure reported to PHMSA occurred on November 22, 2014, when an 8-inch relief valve on a 34-inch gas transmission pipeline operated by Pacific Gas and Electric (PG&E) malfunctioned, which released 119 MMCF of natural gas into the atmosphere until operating personnel were able to bypass the valve. Following the incident, PG&E contractors performed a root cause analysis and made unspecified changes to the pressure limiting station pending a future redesign.²⁷⁹

Out of these incident reports 84 were caused by a malfunction of the relief device or other pressure control equipment.

GAS TRANSMISSION AND REGULATED GAS GATHERING PRESSURE RELIEF DEVICE INCIDENTS

Primary cause and sub-cause	Incidents 2010–2022
Equipment failure: malfunction of control/relief equipment	84
Equipment failure: other equipment failure	5
Equipment failure: threaded connection/coupling failure	2
Equipment failure: defective of loose tubing/fitting	1
Incorrect operation: other incorrect operation	8
Incorrect operation: pipeline/equipment over pressurized	3
Incorrect operation: incorrect valve position	2
Incorrect operation: incorrect equipment	1
Natural force damage: temperature	4
Miscellaneous	2

²⁷⁹ PHMSA, "Pipeline Incident Flagged Files", <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files> (last accessed Dec. 20, 2022) (memorialized within Report ID No. 20140148).

GAS TRANSMISSION AND REGULATED GAS GATHERING PRESSURE RELIEF DEVICE INCIDENTS—Continued

Primary cause and sub-cause	Incidents 2010–2022
Total	112

The most common causes of these failures according to narratives in part G6 or H of operator's gas transmission incident reports are mechanical failures of the relief device, including failures to reseal or reseal after activation, and failures caused when liquid contaminants cause a relief device to freeze open or closed in cold weather conditions. Other reported incidents have resulted from the use of pressure relief devices whose design and material were inappropriate for the pipelines on which they were installed and expected operating conditions. For example, incidents were attributed to improper calibration, design issue with the location of the sensing line, pressure programming or setting issues, improper setpoint, construction, or programming issues, an oversized or undersized pressure relief device and inlet piping, high pipeline flow conditions, and setpoint drift.

Other data sources suggest these incident report figures may undercount relief device emissions that could be prevented through better design, configuration, and maintenance. For example, PHMSA receives inquiries from media sources based on satellite documentation of significant methane releases. Additionally, PHMSA is notified of National Response Center reports on releases involving pressure relief devices in accordance with § 191.5 approximately once a week, with 39 NRC reports referencing relief valves in the description in calendar year 2021.²⁸⁰ Operators report such releases to the National Response Center more frequently than they file incident reports pursuant to §§ 191.9 or 191.15, which suggests that operators may—after reporting them to the National Response Center immediately after discovery of a release—subsequently designate some emissions from relief devices as "intentional" emissions that are not required to be reported to PHMSA as incidents.²⁸¹

²⁸⁰ United States Coast Guard, National Response Center, <https://nrc.uscg.mil/> (last accessed Dec. 20, 2022).

²⁸¹ The discrepancy between events reported to the National Response Center pursuant to § 191.5 and those ultimately reported as incidents pursuant to §§ 191.9 or 191.15 reflects a difference in timing between these two reporting requirements: the § 191.5 reporting requirement obliges operators to notify the National Response Center at "the earliest

Overpressurization is a critical safety issue and can result in a pipeline incident or rupture with grave public safety and environmental consequences. However, inadequate design and configuration of pressure relief devices may result in potentially very large releases beyond that necessary to provide overpressure protection. Additionally, relief device malfunctions due to inadequate maintenance or other issues can result in a failure to provide reliable overpressure protection if it fails to operate or significant emissions if the device leaks or operates unintentionally. PHMSA has observed through inspections and other regulatory oversight activities, that operator procedures, including the choice of design and configuration actuation criteria, may not be optimized to reduce emissions associated with pressure relief device malfunctions or operations beyond what is necessary to provide overpressure protection. For example, some operators take an overly conservative approach to avoiding overpressure conditions and employ design and configuration actuation criteria such that those pressure relief valves will release gas to the atmosphere either more frequently or in greater quantities than necessary to protect against an overpressure condition.

PHMSA proposes to revise § 192.199 to require operators of all new and replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines be designed and configured, as demonstrated by documented engineering analysis, to minimize unnecessary releases of gas. Section 192.199 would prescribe a series of elements that operators must demonstrate would minimize emissions using engineering analysis. These elements include the choice of design material and function, configuration actuation conditions, pressure relief device piping characteristics, presence of isolation valves to facilitate testing and maintenance, and compatibility of material and design with use. In addition, PHMSA proposes a new § 192.773 that, coupled with proposed revisions to § 192.9, would require operators of all gas transmission, distribution, and part 192-regulated gathering pipelines to develop procedures to assess the proper function of pressure relief devices on their facilities and remediate or replace any

practicable" moment—which in practice can mean before a formal decision has been made by the operator to designate an event as an "incident" reported to PHMSA some time (as many as 30 days later) pursuant to §§ 191.9 or 191.15.

malfunctioning devices. This change ensures that operator's maintenance procedures ensure reliable overpressure protection and the minimization of emission from malfunctioning pressure relief devices. PHMSA's proposed language also identifies specific action operators would have to take on operation of a malfunctioning pressure relief device. PHMSA proposes to require a relief device be repaired or replaced immediately if it operates above the pressure limits in § 192.201(a) or § 192.739, fails to operate, or otherwise fails to provide reliable overpressure protection due to the potential consequences of overpressurizing the pipeline.

On the other hand, a relief device that activates below the intended set pressure poses a hazard to the environment, especially if it releases gas at normal operating pressure. Therefore, PHMSA also proposes that if a relief device activates below the set pressure range, the operator must take immediate and continuous action to stop the release of gas and ensure operation with an adequate margin to overpressure conditions. The device must then be repaired or replaced as soon as practicable, and within 30 days. Action to stop the flow of gas should be defined in an operator's abnormal operating procedures and could include reconfiguring the relief device.

In either case the operators would be obliged to maintain records documenting the proper operation and any remediation/replacement of pressure relief devices for the service life of their facilities.

PHMSA understands that its proposed requirements for design, configuration, and maintenance of pressure relief valves discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected gas pipeline operators. PHMSA understands that some affected operators may already have adopted protocols ensuring that the design and configuration of pressure relief devices minimizes emissions of pressurized (natural, toxic, corrosive, or flammable) gases, either voluntarily (to minimize loss of commercially valuable commodities) or in response to State or Federal requirements. The NPRM would backstop those existing practices by enshrining them in regulation by prescribing release mitigation as a mandatory factor in the design and selection of new pressure relief devices; the NPRM contemplates operators would have flexibility within that broad objective to develop their precise implementation strategy for a particular (new) pressure relief device. Similarly,

existing pressure relief device configurations would need to be tweaked to minimize releases as well, but only so far as such configurations can be changed; operators whose pressure relief devices do not admit changes in configuration would not have to effectuate any changes. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop and implement compliance protocols and manage any related compliance costs.

H. Investigation of Failures—§ 192.617

Understanding the causes of pipeline leaks and reasons for malfunction of pressure relief devices is essential for identifying systemic threats to pipeline integrity and preventing similar failures in the future. Although PHMSA regulations at § 192.617 require operators of gas distribution, transmission, offshore gathering, and Type A gathering pipelines to have procedures for analyzing the causes of “failures and incidents,”²⁸² those requirements are limited in application (they do not apply to Types B and C gathering pipelines), and “failure” is not defined in part 192. With respect to the meaning of the term “failure”, operators have applied the definition in the instructions for the Gas Transmission and Gas Gathering Pipeline System Annual Report,²⁸³ which references the broad, functional definition in ASME B31.8, “Gas Transmission and Distribution Piping Systems.” ASME B31.8 defines a failure as the following:

failure: a general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended

function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use.

Although PHMSA has issued interpretations suggesting that leaks caused by certain mechanisms (in particular, those resulting from corrosion) would require investigation pursuant to § 192.617,²⁸⁴ PHMSA regulations do not require investigation of all failures that result in leaks. This limitation could prevent investigations that can identify systemic integrity threats to their pipelines—as well as denies PHMSA and State regulators information necessary to protect public safety and the environment.

PHMSA therefore proposes to address the lack of specificity of the definition of a failure by revising § 192.617 to define the term “failure” for the purposes of that section using language similar to that in ASME B31.8. This approach would facilitate compliance by leveraging elements of a consensus industry standard with which operators are familiar, and portions of which are incorporated by reference elsewhere in PHMSA regulations. Additionally, PHMSA already references ASME B31.8's functional definition of a failure in the instructions for gas transmission and regulated gathering pipeline annual reports. Since a leaking pipe has failed to contain gas, a failure that results in a leak would be required to be investigated in accordance with § 192.617. The proposed definition clarifying that all leaks on pertinent gas pipelines require investigation under § 192.617 would improve safety. The proposed changes are intended to complement the leak grading and repair requirements in this NPRM (as well as repair criteria and IM requirements elsewhere in PHMSA regulations) and equip operators, PHMSA, and State regulators with the information needed in developing proactive initiatives to avoid future pipeline failures. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects this proposed amendment will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the NPRM's proposed compliance timelines—which are based on an effective date of six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to develop

²⁸² PHMSA's discussion of § 192.617 describes the text of that provision as it will be amended on the October 5, 2022, effective date of the Valve Installation and Rupture Detection Final Rule.

²⁸³ PHMSA Form F 7100.2-1 (revision 10-2021), Instruction Revision (10-2021). <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-10/Current%20GT%20GG%20Annual%20Instructions%20-%20PHMSA%20F%207100%20-1%20Approved%2010-2021%20for%20CY%202021%20and%20Beyond.pdf>.

²⁸⁴ PHMSA, Interpretation Response Letter No. PI-92-033 (Jul. 16, 1992).

and implement compliance protocols and manage any related compliance costs.

Although PHMSA proposes to limit the scope of application of this revised definition of “failure” to § 192.617, it acknowledges that term is used elsewhere in PHMSA regulations. PHMSA therefore invites comment on whether the proposed definition of “failure” should instead be located within the broadly applicable definitions at § 192.3 (for potential inclusion within a final rule in this proceeding). Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of that approach, including whether that approach would be technically feasible, cost-effective, and practicable.

I. Type B and Type C Gathering Pipelines—§ 192.9

Types B and C gathering pipelines are not currently subject to all of the part 192 safety requirements broadly applicable to other part 192-regulated gas pipelines, including those pertaining to procedural manuals for operations, maintenance, and emergency response procedures (§ 192.605), patrolling (§ 192.705), and certain recordkeeping (§ 192.709); Type B gathering pipelines are also not subject to emergency planning requirements set forth in § 192.615. Further, because Types B and C gathering pipelines are not subject to § 192.605, some stakeholders have questioned whether those pipelines are excepted from the self-executing requirements within section 114 of the PIPES Act of 2020 for operators to have procedures to eliminate leaks, minimize releases of natural gas, and repair or remediate pipelines known to leak.²⁸⁵ Additionally, most Type C gathering pipelines are, pursuant to § 192.9(f)(1), not even subject to PHMSA’s minimal existing requirements for leakage surveys (§ 192.706) and repair of hazardous leaks (§ 192.703(c)).²⁸⁶

These limitations contribute to public safety and environmental risks. PHMSA has historically imposed each of the requirements listed in the preceding paragraph on gas transmission and Type A gathering pipelines precisely because of the self-evident, appreciable public

safety benefits they entail.²⁸⁷ Although PHMSA previously declined to extend those minimal requirements to Types B and C gathering pipelines (representing the majority of part 192-regulated gathering pipeline mileage),²⁸⁸ the notable public safety and environmental risks from Types B and C gathering pipelines discussed throughout this NPRM warrant removal of those historic regulatory gaps. As described above in section II.C.2, incidents and leaks occur on Type B and Type C gathering pipelines just as they occur on Type A pipelines. For Type B lines, the public safety risks of any incident are evident due to the location of those pipelines in densely-populated Class 2, 3 and 4 locations, while the high operating pressures and large diameters of Type C pipelines entail risks to public safety similar to those posed by Type A pipelines (notwithstanding Type C lines’ location in more sparsely-populated Class 1 areas than Type A lines).²⁸⁹ And as explained above, leaks from any type of natural gas gathering pipeline contains VOCs and HAPs, exacerbating public safety and environmental risk. Leaks of unprocessed natural gas also contain corrosive materials that can accelerate leak degradation.²⁹⁰ The public safety and environmental risks associated with releases (whether leaks or more serious incidents) from gas gathering pipelines also support extension of emergency planning requirements to Type B gas gathering pipelines, which are located in the vicinity of buildings intended for human occupancy; the emergency planning requirements at § 192.615 will ensure that those operators have in place a robust framework for proactive measures to mitigate the public consequences of any emergency on their systems. Lastly, increasing appreciation for the outsized contribution to climate change of fugitive and vented emissions from all natural gas gathering pipelines underscores the importance of minimizing those greenhouse emissions from Types B and C regulated gathering pipelines.

This NPRM therefore proposes a series of regulatory amendments representing a first step in mitigating the

anomalous treatment of Types B and C gathering pipelines in PHMSA regulations. Specifically, PHMSA proposes to revise § 192.9 to add to the list of part 192 requirements applicable to Types B and C pipelines each of its proposed requirements for pressure relief device design and maintenance (§§ 192.199 and 192.773),²⁹¹ certain recordkeeping (§ 192.709) and procedural manual requirements for operations, maintenance, and emergency response (§ 192.605), and—for Type B gathering pipelines—the emergency planning requirements at § 192.615. Each of these requirements have proven utility in minimizing public safety and environmental risks from gas transmission and Type A gathering pipelines and exemplify common-sense programmatic elements that *any* responsible business owning facilities known to transport pressurized, hazardous commodities would maintain in ordinary course (even in the absence of explicit regulatory requirements) to protect public safety and the environment. Extension of the procedural manual requirements at § 192.605 and recordkeeping requirements at § 192.709, moreover, would facilitate regulatory oversight of Types B and C gathering facilities by PHMSA and State inspectors by aligning documentation requirements with existing substantive requirements under § 192.9. It would also dispel any uncertainty among stakeholders regarding application to Types B and C gathering pipelines of the self-executing obligations under section 114 of the PIPES Act of 2020 to eliminate leaks, minimize emissions, and repair or remediate pipelines known to leak based on their material, design, or operating and maintenance history. Extension of the emergency planning requirements in § 192.615 to Type B gathering pipelines would also improve public awareness of pipeline safety and emergency response to incidents on Type B gathering pipelines, bringing requirements for such pipelines in line with existing requirements for all other part 192-regulated gas pipelines. Effective emergency response requirements are critical to ensure the safety of the public, emergency responders, and operator personnel during gas pipeline emergencies on Type B gathering lines, which are located in Class 2, 3, and 4

²⁸⁵ See, e.g., GPA Midstream and American Petroleum Institute, “Joint Comments re Docket No. PHMSA–2021–0039, Pipeline Leak Detection, Leak Repair and Methane Emission Reductions Public Meeting” at 4–5 (May 24, 2021).

²⁸⁶ PHMSA’s RIA for the Gas Gathering Final Rule estimated only ca. 20,000 miles (of the ca. 90,000 total miles of Type C pipelines) would be subject to §§ 192.703 and 192.705. See Gas Gathering RIA at 15.

²⁸⁷ PHMSA, “Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards,” 71 FR 13289, 13292 (Mar. 15, 2006).

²⁸⁸ See Gas Gathering RIA at 15 (noting a total of ca. 90,000 miles of Type C gathering pipelines) and 30 (noting a total of ca. 11,000 miles of Types A and B gathering pipelines).

²⁸⁹ See Gas Gathering Final Rule at 63267.

²⁹⁰ Leaks from part 192-regulated gathering lines transporting flammable, toxic, or corrosive gases other than natural gas also entail their own safety and environmental risks.

²⁹¹ As explained elsewhere, PHMSA’s proposed § 192.199 requirements would only apply to new, replaced, relocated, or changed Type C gathering pipelines.

locations.²⁹² Section 192.615 includes requirements to ensure effective emergency preparedness, including a coordinated operator and community response to pipeline emergencies. Moreover, this requirement would ensure that operators of Type B gathering lines are prepared to take appropriate immediate and continuous actions in response to a grade 1 leak, which could require activation of an emergency response plan. PHMSA further proposes (as discussed above) to extend the suite of enhanced leak detection and repair-related proposals elsewhere in this NPRM to certain Types B and C gathering pipelines (including §§ 192.703(c) and (d), 192.705, 192.706, 192.709, 192.760, 192.763, and 192.769). Similarly, PHMSA also proposes to extend requirements for this NPRM's elements pressure relief device maintenance (§ 192.773) to Types B and C gathering pipelines to further reduce emissions and public safety and environmental risks associated with Types B and C gathering pipelines.

PHMSA expects the above proposed first steps toward improving alignment of regulatory requirements for Types B and C gas gathering pipelines with those applicable to other part 192-regulated pipelines would be reasonable, technically feasible, cost-effective, and practicable. The specific regulatory requirements PHMSA proposes to extend are common-sense, widely-employed approaches adopted by reasonably prudent operators in ordinary course to minimize losses of commercially valuable commodities and risks to public safety and the environment from the operation of pipelines transporting pressurized (natural, corrosive, toxic, or flammable) gases. Precisely for that reason, PHMSA expects that some Types B and C gas gathering pipeline operators may already voluntarily comply with those proposed requirements. Those and other operators of Types B and C gas gathering pipelines (some of which operators may also operate either gas transmission or Type A gathering pipelines) may also have pipelines within their systems subject to similar procedural manual, recordkeeping, and pressure relief device requirements under Federal or State law; those existing procedural manuals and (recordkeeping and pressure relief device design and configuration) protocols could be

extended and adapted to Types B and C gas gathering pipelines. Viewed against those considerations and the compliance costs estimated in the Preliminary RIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, the proposed compliance timelines—based on an effective date of the proposed requirements six months after the publication date of a final rule in this proceeding (which would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes to existing procedural manuals and protocols (and conduct any accompanying personnel training) and manage any related compliance costs.

PHMSA solicits comment on additional opportunities to harmonize part 192 treatment of regulated gathering pipelines for potential inclusion within a final rule in this or a subsequent rulemaking proceeding. Comments on this question are especially helpful if they address the potential safety and environmental benefits and potential costs of a particular approach, including whether that approach would be technically feasible, cost-effective, and practicable.

J. Miscellaneous Changes in Parts 191 and 192 To Reflect Codification in Federal Regulation of the Congressional Mandate To Address Environmental Hazards of Leak From Gas Pipelines

As discussed above in section II.D, current PHMSA regulations reflect an ambiguous distinction between “hazardous” and other leaks that reflects PHMSA’s historical prioritization of public safety hazards. PHMSA’s regulations at parts 191 and 192 consequently contain numerous references to “potentially hazardous” gas releases, or to “hazards” expressed principally in terms of public safety risks. As discussed above in sections II.D.3, III.C.1, and III.C.6, all “leaks” are necessarily hazardous to the environment, and even a small leak can be hazardous to public safety, especially if it is allowed to continue indefinitely without repair and potentially degrade into a more serious leak or incident. PHMSA therefore proposes miscellaneous conforming revisions to various provisions of parts 191 and 192 consistent with the PIPES Act of 2020’s direction. PHMSA proposes to define “hazardous leak or leak” in § 192.3 and apply it to those subparts of part 192 other than the IM regulations under

subparts O and P. That proposed definition would make “hazardous leak” synonymous to “leak.” PHMSA also proposes to delete language in several places in part 192 suggesting contingency (for example, references to “*potentially* hazardous” releases) at each of §§ 192.503(a)(2), 192.507(a), 192.509(a), 192.513(b), 192.553(a)(2), 192.557(b)(2), and 192.751(a) regarding hazards posed by releases from gas pipelines.²⁹³ For other provisions (specifically, §§ 192.605(b)(9), 192.613(b), 192.615(a), 192.615(a) introduction, 192.616(d)(2) and (j)(2), and 192.703(c)), existing language referring to “hazard” and “hazardous leak” is elastic enough to accommodate PHMSA’s proposed expansion of the “hazard” concept to encompass environmental hazards without revision of regulatory text. Although the expansion of the “hazard” concept may require some operators to modify procedures and practices, PHMSA expects any compliance burdens would be *de minimis* because a reasonably prudent operator would employ practices and procedures addressing the need to minimize releases of natural gas and other environmental harms from their activities. In addition, the mechanism for public safety and environmental harms (the release of gas from a pipeline) is the same.

This proposed expansion of “hazardous leaks” to encompass hazards to the environment and public safety could lead operators to modify testing practices. For example, PHMSA’s proposed changes to subpart J testing requirements (specifically, §§ 192.503(a)(2), 192.507(a), 192.509(a), 192.513(b)) to limit placement into service of any new, replaced, relocated or otherwise changed gas transmission, distribution, offshore gathering, Types A, B, and C gathering pipeline segments with *any* leak could make testing and qualification of new, replaced, relocated, or changed pipelines more difficult in that it would require conforming revisions to operator acceptance criteria. However, PHMSA expects the impact of those proposed revisions would be *de minimis*, as reasonably prudent operators would not place new, replaced, relocated, or changed pipeline segments into service

²⁹³ PHMSA will also propose conforming revisions to the part 191 annual report forms and instructions for each of gas transmission, offshore gathering and Types A, B, and C gathering pipelines (F7100.2–1), Type R gas gathering pipelines (F7100.2–3), and gas distribution pipelines (F7100.1–1) to eliminate distinctions made or suggested in those documents between hazardous leaks, other leaks, or other gas releases allegedly too small to merit reporting.

²⁹² Type B gathering pipelines are defined in § 192.8 as those gathering pipelines located in Class 4, Class 3, and certain Class 2 locations with the operating characteristics specified in Table 1 to § 192.8(c)(2).

if they had observed any leak during initial testing. The same logic would extend to its proposed amendment of uprating requirements (at §§ 192.553(a)(2), 192.557(b)(2)) applicable to gas transmission, distribution, offshore gathering, and Type A gathering pipelines.

PHMSA does not propose to expand every reference to “hazard” or “hazardous leak” in PHMSA’s part 191 and 192 regulations to encompass environmental hazards. First, PHMSA proposes to exclude the IM regulations at subparts O and P from application of the new definition of “leak or hazardous leak” at § 192.3 to keep operator IM plans—and operators’ limited resources implementing those plans—focused on identification and management of public safety risks.²⁹⁴ PHMSA is proposing to revise § 192.1007 to delete a reference to § 192.703(c) that would be rendered obsolete by the limited application of PHMSA’s proposed definition of “leak or hazardous leak” at § 192.3. Second, PHMSA is not proposing to refer to “hazards” or leaks “hazardous to public safety” where an explicit reference to environmental hazards would either be unnecessary (e.g., because other subparagraphs within the same provision would address any environmental hazards) or inapposite to the pertinent requirement. This applies to §§ 192.605(c)(1)(v), 192.605(a)(6) and (7), 192.615(c), and 192.721. Similarly, PHMSA proposes to revise other references to (unqualified) “hazards” to preserve those provisions’ historical and appropriate focus on public safety, rather than environmental, hazards. Generally, those proposed regulatory amendments would consist of addition of qualifying language (“hazard(s) to public safety”) where an explicit reference to environmental hazards would either be unnecessary (e.g., because other, related provisions or paragraphs would address any environmental hazards) or inapposite to the pertinent requirement. PHMSA proposes these conforming amendments for §§ 191.23(a)(9), 192.167(a)(2), 192.169(b), 192.179(c), 192.199(e), 192.361(f)(3), 192.363(c), 192.629(a) and (b), 192.727(b) and (c) and 192.751. Third, even though PHMSA does not propose to expand the concept of “hazard” uniformly across its regulations, operators nevertheless may voluntarily supplement the baseline requirements of PHMSA regulations by explicitly incorporating environmental

harms from releases of gas from their pipelines throughout their policies, procedures, and practices.

PHMSA expects no material impact on operators’ existing practices from the above proposed new definition (along with the limited, conforming revisions specified above), which supports a conclusion that those proposed amendments would be reasonable, technically feasible, cost-effective, and practicable. PHMSA invites comment by stakeholders on the appropriateness of each of its above proposed revisions to, or preservation of, existing regulatory references to “hazards” and “hazardous leaks” for potential modification of its above proposed amendments in any final rule issued in this proceeding. PHMSA also solicits comment on whether any provisions not addressed above would also benefit from conforming revision. Should stakeholders proffer alternative or additional regulatory amendments, they should support those proposals by reference to each of any expected safety and environmental benefits, as well as the cost-effectiveness, practicability, and technical feasibility.

V. Section-By-Section Analysis

§ 191.3 Definitions

PHMSA proposes to revise § 191.3 to add a definition for large-volume gas releases that must be reported, per the new § 191.19. PHMSA proposes to define a “large-volume gas release” as an intentional or unintentional release of gas of 1 MMCF or more. This new large-volume gas release reporting requirement would be applicable to all gas pipeline facility operators, including (but not limited to) operators of jurisdictional underground storage and LNG facilities, as well as Type R gas gathering pipelines.

PHMSA also proposes revision of the property damage criterion within the definition of “incident” to exclude certain indirect costs associated with the cost incurred by operators in conducting repair activity. In particular, the revised definition excludes the cost of preparing and obtaining permits, as well as the removal and replacement of third-party infrastructure that was not itself damaged by the event. For example, if a release from a pipeline beneath a street did not damage a roadway, but pavement must be temporarily removed to repair the pipeline, the costs of the roadway repair and associated permits would not be included in the definition of property damage.

§ 191.11 Distribution System: Annual Report

PHMSA proposes to change Form F7100.1–1 and its instructions to collect data on leaks detected and repaired by grade in the annual reporting period and the number (by grade) of unrepaired leaks at the conclusion of the annual reporting period. PHMSA also proposes to change the gas distribution annual report form to include estimated aggregate emissions from leaks by grade and other emissions categorized by source category (similar to those in the tables in section II.C) on an operator’s system over the annual reporting period. PHMSA also proposes to revise miscellaneous sections of those annual reports and their instructions to remove statements expressing or suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. Such leaks and leak repairs would instead be recorded as a separate line item similar to the existing collection related to mechanical fitting failures to ensure a complete accounting of the number of releases from gas distribution pipelines.

§ 191.17 Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities; Annual Report

PHMSA proposes to change the gas transmission and regulated gathering annual report form (Form F7100.2–1) and its instructions to collect data on leaks detected and repaired by grade during the annual reporting period. This form change is applicable to gas transmission, offshore gas gathering, and Type A, B, and C regulated onshore gas gathering pipelines. PHMSA also proposes to change Form F7100.2–1 to include estimated aggregate emissions from leaks by grade and other emissions by source category from an operator’s system over the annual reporting period. PHMSA does not propose changes to the Type R annual report form (Form F7100.2–3). Lastly, PHMSA proposes to revise miscellaneous sections of the annual reports (and accompanying instructions) for each of gas transmission, offshore gathering, and regulated onshore gathering pipelines (Form F7100.2–1), Type R gathering pipelines (Form F7100.2–3) and LNG facilities (Form F7100.3–1) to remove statements expressing or suggesting that releases that can be eliminated by routine maintenance (such as lubrication, tightening, or adjustment) need not be reported as leaks. A count of leaks eliminated by routine

²⁹⁴ Similarly, this proposed definition would not apply to IM programs for UNGSFs, which are not subject to any requirements of part 192 aside from § 192.12(d).

maintenance would instead be reported as a separate line item on the annual report form.

§ 191.19 Large-Volume Gas Release Reports

PHMSA proposes to create a new § 191.19 requiring operators to submit reports of large-volume gas releases. Like incident reports, this requirement would be applicable to all operators of PHMSA-jurisdictional gas pipeline facilities, including operators of jurisdictional underground storage and LNG facilities, as well as Type R gas gathering pipelines. The term “large-volume gas release” is defined in proposed amendments to § 191.3, as described above. The report would be required for releases that become reportable on or after the effective date of a final rule.

The new proposed report would require pertinent operators to report both intentional and unintentional releases of 1 MMCF or more of gas. This new form would capture both unintentional, fugitive emissions (*e.g.*, from leaks) as well as blowdowns, maintenance related venting, pressure relief device actuations, and other intentional, vented emissions. Operators would be required to submit a report within 30 days from the date that a release known at detection to be 1 MMCF or more was detected, or 30 days from the date that a previously detected release became reportable. If the time the leak started is unknown, operators should base the calculation based on estimated release volume from the date of the most recent leakage survey.

PHMSA also notes that events reported as incidents under §§ 191.9 or 191.15 would not also need to be reported pursuant to the proposed § 191.19 unless the total release volume at cessation exceeds 10% of the volume estimated in the incident report. If an unintentional release reported as a large-volume gas release report subsequently becomes reportable as an incident due to updated release volume estimates or consequences (or for any other reason), the operator would have to resubmit it as an incident report appropriate for the facility type.

§ 191.23 Reporting Safety-Related Conditions

Consistent with PHMSA’s current treatment of releases reportable as incidents, PHMSA proposes to except large-volume gas releases as defined in proposed § 191.3 from the requirement to submit a safety-related condition report pursuant to § 191.23. PHMSA also proposes to amend § 191.23(a)(9) to explicitly limit that safety-related

condition reporting requirement to imminent hazards to public safety.

§ 191.29 National Pipeline Mapping System

PHMSA proposed to delete the current exemption for offshore gas gathering, and Types A, B, and C gathering pipelines from NPMS reporting requirements at § 191.29(a), thereby obliging operators of those pipelines to submit geospatial pipeline location data to NPMS. PHMSA does not propose to require operators of Type R, reporting-only, gas gathering lines to participate in the NPMS.

§ 192.3 Definitions

Section 192.3 defines a number of terms that are referenced in part 192. PHMSA proposes to add a few definitions, primarily those associated with leak detection and repair. These are primarily referenced in proposed § 192.760 for the purposes of leak grading and repair requirements.

PHMSA proposes to define a “confined space” as any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These would include vaults, catch basins, and manholes. Unlike a building, a confined space is not ordinarily occupied for residential, commercial, or industrial uses. The difference between a confined space and a substructure is that a confined space is large enough to accommodate a person, while a substructure is not. Consistent with the GPTC Guide, this definition differs from the definition of a “confined space” used by OSHA at 29 CFR 1910.146(b).

PHMSA proposes to define a “gas-associated substructure” as a substructure that is part of an operator’s pipeline facility but that is not itself designed to convey or store gas. These would typically consist of small vaults for devices, such as valves, meters, regulators, or other equipment.

PHMSA proposes to define a “substructure” as any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures would include telephone and electrical service boxes and associated ducts and conduits, valve boxes, and meter boxes.

PHMSA proposes to define, for the purposes of all subparts of part 192 other than IM requirements in § 192.12(d) and subparts O and P, a “leak or hazardous leak” as any release of gas from a pipeline that is uncontrolled at the time of discovery and is an existing, probable, or future hazard to persons (including operating

personnel), property, or the environment, or any uncontrolled release of gas from a pipeline that is detectable via equipment, sight, sound, smell, or touch. PHMSA proposes to require that each leak must be investigated, graded, and repaired in accordance with proposed § 192.760. This includes leaks that are identified by the public or emergency personnel. Leaks include unintended releases through intended release pathways. For example, a pressure relief device or emergency shutdown device that fails and releases gas through a vent or flare is a leak.

PHMSA proposes to define the “lower explosive limit (LEL)” as the minimum concentration of vapor in air below which propagation of a flame does not occur in the presence of an ignition source at ambient temperature and pressure. The LEL of natural gas is 5% methane in air by volume. The LEL for propane is 2.1% propane in air by volume. The LEL for hydrogen gas is 4% hydrogen by volume.

PHMSA proposes to define a “tunnel” as a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate. Compared with a confined space, a tunnel is intended for regular or occasional human occupancy.

PHMSA proposes to define a “wall-to-wall paved area” as an area where the ground surface between the curb of a paved street and the front wall of a building is continuously paved with hard top surface impermeable to gas, excluding non-continuous landscaping such as tree plots.

§ 192.9 What requirements apply to gathering lines?

The NPRM proposes a series of amendments to § 192.9 to improve protection of public safety and the environment from leaks and incidents on all part 192-regulated onshore and offshore gathering lines, and to improve alignment between the part 192 safety requirements applicable to each of Types A, B, and C gathering pipelines.

Requirements for Type A gathering pipelines are defined in § 192.9(c), which requires that a Type A pipeline comply with the requirements of part 192 for transmission lines, subject to specific exceptions listed in that paragraph. PHMSA proposes no change to that paragraph. All Type A gathering pipelines would therefore be subject to the proposals introduced within the NPRM for transmission lines, including each of the following: revised definitions, to include a definition of “leak or hazardous leak” to account for environmental hazards in connection

with non-IM subparts of part 192 (§ 192.3); engineering analyses for the design of pressure relief devices (§ 192.199); modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513); modification of procedural manuals to provide for elimination of leaks and minimize releases of gas as well as remediation or replacement of pipelines known to leak (§ 192.605); revision of failure investigation procedures for investigation of leaks (§ 192.617); enhanced patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); new limitations on uprating pipelines (§§ 192.553 and 192.557); new leak detection personnel qualification requirements (§ 192.769); specific requirements for minimization of blowdown emissions (§ 192.770), and new pressure relief device maintenance requirements (§ 192.773). PHMSA also proposes that Type A gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility with respect to each of the following: use of alternative leak detection equipment in non-HCA, Class 2 locations in complying with § 192.706; use of an alternative performance standard in Class 2 locations in complying with § 192.763; and extension of leak repair timelines set forth in § 192.760.

Part 192 requirements for Type B gathering pipelines are listed in § 192.9(d); part 192 requirements not listed in § 192.9(d) are generally inapplicable to Type B gathering pipelines. With respect to new, relocated, replaced, or otherwise changed Type B gathering lines, PHMSA proposes (consistent with its proposals for other regulated gathering lines) each of the following: a new § 192.199 prescribing engineering analyses for the design of pressure relief devices; and modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513). PHMSA also proposes to revise § 192.9(d) to add to the list of part 192 operations (subpart L) and maintenance (subpart M) requirements applicable to all Type B gathering pipelines a number of requirements for enhancing Type B operator leak detection, grading and repair programs, including the following: revised definitions, to include a definition of “leak or hazardous leak” to account for

environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); introduction of procedural manuals providing for, among other things, the elimination of leaks and minimizing releases of gas as well as remediation or replacement of pipelines known to leak (§ 192.605); patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); and new pressure relief device maintenance requirements (§ 192.773). PHMSA has not proposed that operators of Type B gathering pipelines would be subject to new vented emissions mitigation requirements at proposed § 192.770. Further, PHMSA’s proposed revision referencing § 192.605 procedural manual requirements would dispel any stakeholder confusion regarding whether Type B gathering pipelines are subject to the self-executing requirements at section 114 of the PIPES Act of 2020 to eliminate leaks, minimize releases of natural gas, and remediate or replace pipelines known to leak. PHMSA also proposes that Type B gathering pipelines would be subject to emergency response manual documentation requirements at § 192.605 and emergency planning requirements at § 192.615. Under § 192.605(b)(1) and (b)(2), operators must include procedures for compliance with the subpart M and subpart I requirements applicable to the Type B lines in accordance with § 192.9, but they are not required to have procedures for other subparts M and I requirements. Similarly, operators of Type B gathering lines are not required to have procedures for complying with § 192.631 control room management requirements referenced in § 192.605(b)(12), nor for the continuing surveillance and accident investigation requirements referenced in § 192.605(e). Additionally, PHMSA proposes that Type B gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility with respect to each of the following: use of alternative leak detection equipment in non-HCA, Class 2 locations in complying with § 192.706; extension of leak repair timelines set forth in § 192.760; and use of an alternative performance standard in Class 2 locations in complying with § 192.763.

PHMSA also proposes a number of revisions to § 192.9 paragraphs identifying specific part 192 requirements applicable to Type C

gathering pipelines to promote alignment with regulatory requirements applicable to other regulated onshore gathering pipelines and reduce fugitive and vented emissions. Specifically, PHMSA proposes to revise § 192.9(e) to expand the list of part 192 operations (subpart L) and maintenance (subpart M) requirements applicable to all Type C gathering pipelines to include a number of requirements to enhance Type C operator leak detection, grading and repair programs, including the following: revised definitions, to include a definition of “leak or hazardous leak” to account for environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); procedural manuals providing for, among other things, elimination of leaks and minimize releases of natural gas as well as remediation or replacement of pipelines known to leak (§ 192.605); patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); and pressure relief device maintenance requirements (§ 192.773). PHMSA also proposes that new, replaced, relocated, or changed Type C gathering lines would be subject to the pressure relief device design and configuration requirements at § 192.199, as well as modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513). PHMSA has not proposed that operators of Type C gathering pipelines would be subject to its proposed new limitations on uprating pipelines at §§ 192.553 and 192.557, or the vented emissions mitigation requirements at proposed § 192.770. PHMSA also proposes revision to § 192.9(f)(1) to narrow the exceptions identified in that subparagraph to ensure that all Type C gathering pipelines are subject to leakage survey and repair requirements. Further, PHMSA’s proposed revision referencing § 192.605 procedural manual documentation requirements would dispel any stakeholder confusion regarding whether Type C gathering pipelines must have emergency response manuals, or are subject to the self-executing requirements at section 114 of the PIPES Act of 2020 to eliminate leaks, minimize releases of natural gas, and replace or remediate pipelines known to leak. Under § 192.605(b)(1) and (b)(2), operators must include procedures for compliance with the subpart M and subpart I requirements applicable to the Type C

pipeline in accordance with § 192.9, but they are not required to have procedures for other subparts M and I requirements. Similarly, operators are only required to have procedures for submitting safety-related condition reports on Type C gathering lines if the pipeline is subject to the safety-related condition reporting requirement in § 191.23 (*i.e.*, the pipeline is required to have an MAOP). Further, operators of Type C gathering lines are not required to have procedures for complying with § 192.631 control room management requirements referenced in § 192.605(b)(12), nor for the continuing surveillance and accident investigation requirements referenced in § 192.605(e). PHMSA also proposes that Type C gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility in each of the following: use of alternative leak detection equipment in non-HCA, Class 1 locations in complying with § 192.706; use of an alternative performance standard in Class 1 locations in complying with § 192.763; and extension of leak repair timelines set forth in § 192.760.

Lastly, PHMSA proposes minor changes to the language in § 192.9(b) listing part 192 requirement to which offshore gas gathering pipelines are exempt: specifically, PHMSA has added language stating explicitly that offshore gas gathering pipelines would be exempt from the default grade 2 classification requirement and at § 192.763(c)(1)(vi) and the 30-day repair requirement at § 192.763(c)(3). PHMSA has not otherwise proposed to modify § 192.9(b). However, because PHMSA is proposing a number of revisions to part 192 requirements applicable to gas transmission lines, those proposed requirements would apply to offshore gathering pipelines as well pursuant to § 192.9(b). Specific proposals that would apply to offshore gathering pipelines include each of the following: revised definitions, to include a definition of “leak or hazardous leak” to account for environmental hazards in connection with non-IM subparts of part 192 (§ 192.3); engineering analyses for the design of pressure relief devices (§ 192.199); modification of initial testing requirements to account for environmental hazards (§§ 192.503, 192.507, 192.509, and 192.513); new limitations on uprating pipelines (§§ 192.553 and 192.557); modification of procedural manuals to provide for elimination of leaks and minimize releases of gas as well as remediation or replacement of pipelines known to leak (§ 192.605); revision of failure

investigation procedures for investigation of leaks (§ 192.617); enhanced patrolling requirements (§ 192.705); enhanced leakage survey requirements (§ 192.706); new leak grading, repair, and documentation requirements (§§ 192.703(c) and (d), 192.709, 192.760 and 192.763); new leak detection personnel qualification requirements (§ 192.769); specific requirements for minimization of blowdown emissions (§ 192.770), and new pressure relief device maintenance requirements (§ 192.773). PHMSA also proposes that offshore gas gathering pipeline operators would be able to submit for PHMSA review a notification pursuant to § 192.18 for flexibility with respect to each of the following: use of an alternative ALDP performance standard in complying with § 192.763; and extension of leak repair timelines set forth in § 192.760. PHMSA has not proposed that offshore gas gathering pipelines would be subject to its proposed default requirement within § 192.763 for any leak be considered a grade 2 leak at a minimum.

§ 192.12 Underground Natural Gas Storage Facilities

Section 192.12(c) obliges operators of underground natural gas storage facilities to have and follow written procedures for operations, maintenance, and emergency response activities. PHMSA proposes to revise the regulatory language in this provision to incorporate within its regulations the section 114 of the PIPES Act of 2020 self-executing mandate that operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities.

§ 192.18 How To Notify PHMSA

PHMSA proposes to revise § 192.18(c) to cross reference proposed amendments in the NPRM that allow an operator flexibility in complying with certain part 192 requirements. Specifically, the NPRM proposes to allow operators to use alternative compliance approaches with advance notification to PHMSA in connection with the following requirements: use of leak detection equipment for leakage surveys on onshore gas transmission and certain regulated gathering pipelines (§ 192.706(a)(2)); for each of natural gas transmission and gathering operators with pipelines in Class 1 or 2 locations, as well as operators of any part 192-regulated gas pipeline transporting gas other than natural gas, implementation of an alternative ALDP performance standard as well as alternative leak detection equipment (§ 192.763(c)); and minimum leak repair

schedules (§ 192.760(h)). Each of these flexibilities is described separately under its respective discussion in this section V. As specified in existing § 192.18, an operator must notify PHMSA 90 days in advance of using an alternative compliance approach and may begin to use that alternative approach if they do not receive a letter after 90 days objecting to that alternative compliance approach from PHMSA.

§ 192.167 Compressor Stations: Emergency Shutdown

PHMSA proposes to revise § 192.167(a)(2) governing on new, replaced, relocated, or otherwise changed compressor stations on gas transmission and part 192-regulated onshore gas gathering pipelines to state that blowdowns of those facilities during emergency shutdowns must be directed toward locations where the released gas would not create a hazard to *public safety* specifically.

§ 192.169 Compressor Stations: Pressure Limiting Devices

PHMSA proposes to revise § 192.169(b) governing on new, replaced, relocated, or otherwise changed gas compression stations on gas transmission pipelines and boosting stations on part 192-regulated gathering pipelines to state that vent lines from pressure relief devices must exhaust gas to locations that would not create a hazard to public safety specifically.

§ 192.179 Transmission Line Valves

PHMSA proposes to revise § 192.179(c) governing blowdown valves on new, replaced, relocated, or otherwise changed gas transmission and Types A, B, and C gathering pipelines to state that the discharges from those valves must be located such that blowdowns to atmosphere would not create a hazard to public safety specifically.

§ 192.199 Requirements for Design and Configuration of Pressure Relief and Limiting Devices

PHMSA proposes to revise § 192.199 to require that all new, replaced, relocated, or otherwise changed overpressure protection devices be designed and configured to minimize unnecessary releases of gas to the atmosphere. Since § 192.199 is a generally applicable design requirement, this proposed amendment would apply to all facilities regulated under part 192, including gas transmission, distribution, offshore gas gathering, and Types A, B, and C onshore gas gathering pipelines. This requirement would not be retroactive,

and thus would not apply to any pressure relief device on pipelines existing on or before the effective date of the rule unless the pipeline is subsequently replaced, relocated, or otherwise changed.

To comply with this proposed requirement, each pressure relief device must be designed and configured based on a documented engineering analysis demonstrating that the set and reset conditions of the device, as well as the size and configuration of it and its associated piping, are appropriate for providing adequate overpressure protection. Additionally, the design and materials used for the relief device must be compatible with the composition of the gas being transported and be suitable for the anticipated operating and environmental conditions. The design of the relief device would need to include isolation valves to support testing and maintenance.

Lastly, PHMSA proposes revision of § 192.199(e) to require that all new, replaced, relocated, or otherwise changed pressure relief and limiting devices on gas transmission, distribution, offshore gas gathering, and Types A, B, and C gas gathering pipelines would need to have discharge stacks, vents, or outlet ports located where gas can be discharged into the atmosphere without undue hazards to public safety specifically.

§ 192.361 Service Lines: Installation

PHMSA proposes revision of § 192.631(f)(3) governing new, replaced, relocated, or otherwise changed underground service lines installed under buildings to provide that vents from service line annular spaces must be to locations that would not create a hazard to public safety specifically.

§ 192.363 Service Lines: Valve Requirements

PHMSA proposes revision of § 192.363(c) governing design and construction requirements for valves on high-pressure service lines to limit that requirement to, among other things, certain high-pressure service lines installed in areas where blowdowns of gas would be hazardous to public safety specifically.

§ 192.503 General Requirements

PHMSA proposes to revise § 192.503(a)(2) governing initial testing requirements on new, replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines to delete the qualification “potentially” modifying “hazardous leak” in recognition of the certainty of

environmental harms from any released natural gas, flammable gas, toxic gas, or corrosive gas.

§ 192.507 Test Requirements for Pipelines To Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or Above 100 p.s.i. (689 kPa) Gage

PHMSA proposes to revise § 192.507(a) governing certain initial testing requirements on new, replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines to delete the qualification “potentially” modifying “hazardous leak” in recognition of the certainty of environmental harms from any released gas.

§ 192.509 Test Requirements for Pipelines To Operate Below 100 p.s.i. (689 kPa) Gage

PHMSA proposes to revise § 192.509(a) governing initial testing requirements on new, replaced, relocated, or otherwise changed gas transmission, distribution, and part 192-regulated gathering pipelines (other than service and plastic pipelines) to delete the qualification “potentially” modifying “hazardous leak” in recognition of the certainty of environmental harms from any released gas.

§ 192.513 Test Requirements for Plastic Pipelines

PHMSA proposes to revise § 192.513(b) governing initial testing requirements on new, replaced, relocated, or otherwise changed plastic gas transmission, distribution, and part 192-regulated gathering pipelines to delete the qualification “potentially” modifying “hazardous leak” in recognition of the certainty of environmental harms from any released gas. PHMSA also proposes an editorial correction of the word “insure” to “ensure.”

§ 192.553 General Requirements

PHMSA proposes to revise the general requirements for uprating to clarify that any hazardous leaks detected during the uprating process on gas transmission, distribution, offshore gathering, and Type A gathering lines must be repaired prior to further increasing the pressure of the pipeline during the incremental pressure increase procedure in § 192.553(a). This requirement would apply to any gas transmission, distribution, or Type A gathering pipeline subjected to an incremental increase in operating pressure as described in § 192.553.

§ 192.557 Uprating: Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines

PHMSA proposes to revise § 192.557(b)(2) to require that operators of gas transmission, distribution, offshore gathering, and Type A gathering pipelines repair any hazardous leaks (note that PHMSA proposes to define leaks and hazardous leaks identically in § 192.3) that are found prior to uprating a pipeline that will operate at an MAOP producing a hoop stress less than 30 percent of SMYS, or that is made of plastic, cast iron, or ductile iron. A pipeline with an active leak would therefore not be permitted to be uprated to a higher MAOP until each leak repair was complete.

§ 192.605 Procedural Manual for Operations, Maintenance, and Emergencies

Existing § 192.605 requires each operator of an onshore or offshore gas transmission pipeline, gas distribution pipeline, offshore gas gathering pipeline, or Type A gas gathering pipeline to prepare and follow a written procedure manual for operations, maintenance, and emergency response activities. PHMSA proposes to revise § 192.9 to extend those procedural documentation requirements to Types B and C gas gathering pipelines, excluding requirements for procedures that are not applicable to such pipelines. PHMSA also proposes to revise § 192.605 to incorporate the self-executing mandate at section 114 of the PIPES Act of 2020 that the maintenance and operating procedures for part 192-regulated gas pipelines must include procedures for each of the elimination of leaks and for minimizing releases of gas from pipelines, as well as the remediation or replacement of pipelines known to leak based on their material, design, or past maintenance and operating history. These proposed amendments to §§ 192.9 and 192.605 would dispel any stakeholder uncertainty regarding application of the self-executing requirements in section 114 of the PIPES Act of 2020.

§ 192.617 Investigation of Failures

For the purposes of the existing requirement to investigate failures, PHMSA proposes to define the term “failure” for the purposes of § 192.617 to mean “when any portion of a pipeline becomes inoperable, is incapable of safely performing its intended function, or has become

unreliable or unsafe for continued use.” PHMSA considers any leaking gas pipeline as having failed to perform its intended function. This proposed regulatory amendment would apply to gas distribution, gas transmission, offshore gas gathering, and Type A regulated onshore gas gathering pipelines.

§ 192.629 Purging of Pipelines

PHMSA proposes to revise its provisions governing the purging of gas from each of gas transmission, distribution, offshore gathering and Type A gathering pipelines to clarify that this provision remains focused on addressing risks to public safety associated with purging of gas from those pipelines. PHMSA also proposes editorial amendments replacing the term “released” with “introduced” to more accurately reflect that gas is being injected into the pipeline and replacing the term “line” with “pipeline.”

§ 192.703 General

As discussed above and below, PHMSA is proposing to delete the historical reference to “hazardous leak” in § 192.703 (which qualification limited the general repair requirement in that provision) and replace it with a reference to PHMSA’s proposed § 192.760 leak grading and repair requirements. PHMSA’s proposed revisions to §§ 192.703 (when coupled with proposed amendments to § 192.9) would extend the scope of the § 192.703 general leak repair requirement to all part-192 regulated gas pipelines.

PHMSA also proposes an exception from proposed requirements listed in § 192.703(d) for gas transmission compression and gathering boosting stations subject to EPA methane emissions monitoring and repair requirements within current 40 CFR part 60, subpart OOOOa regulations; proposed subpart OOOOb updates and subpart OOOOc methane emissions guidelines (as implemented through EPA-approved State plans with standards at least as stringent as EPA’s emission guidelines in subpart OOOOc or implemented through a Federal plan).²⁹⁵ Specific proposed requirements from which eligible stations would be excepted include the following: leak repair (§ 192.703(c)), leakage survey and patrol (§§ 192.705 and 192.706), leak grading and repair (§ 192.760), ALDPs (§ 192.763), and

qualification of leak detection personnel (§ 192.769).

§ 192.705 Transmission Lines: Patrolling

Visual right-of-way patrols with or without the use of leak detection equipment are required by § 192.705 on gas transmission lines and are an important supplement to leakage surveys. PHMSA proposes to increase the minimum required frequency of right-of-way patrols on gas transmission, offshore gathering, and Type A gathering pipelines to at least 12 times each calendar year, with intervals between patrols not exceeding 45 days, regardless of location. PHMSA also proposes to revise § 192.9 to require operators perform patrols of Type B and Type C regulated onshore gas gathering pipelines on the same interval. An operator may combine a patrol pursuant to § 192.705 with a leakage survey pursuant to § 192.706, provided their procedures include both a visual survey of the right-of-way and a leakage survey with leak detection equipment.

§ 192.706 Transmission Lines: Leakage Surveys

PHMSA proposes to revise § 192.706 to increase the minimum frequency for performing leakage surveys of gas transmission, offshore gas gathering, and Types A, B, and C gathering pipelines, each located in HCAs in Class 1, Class 2, and Class 3 locations, to twice each calendar year at intervals not exceeding 7½ months. PHMSA also proposes revision of § 192.9 to extend § 192.706 leak survey requirements to all Type C gathering pipelines. Further, PHMSA proposes to increase the minimum frequency for performing leakage surveys of gas transmission and Types A and B gathering pipelines located in HCAs in Class 4 locations to four times each calendar year at intervals not exceeding 4½ months.

PHMSA proposes to require each leakage survey on an onshore gas transmission pipeline or Type A, B, or C gathering pipeline to be performed using leak detection equipment and methods that meet the ALDP performance standard in the proposed § 192.763. This proposed change would eliminate the existing automatic, generically available exception at § 192.625 from requirements to use leak detection equipment for gas transmission and Types A and B gathering pipelines in Class 1 and Class 2 locations and odorized pipelines in Class 3 and Class 4 locations. Leakage surveys for onshore gas transmission and Types A, B, and C gathering pipelines would only be performed

without the use of leak detection equipment (*i.e.*, solely with the use of human or animal senses) with prior notification and review by PHMSA in accordance with § 192.18, and may only be approved in non-HCA, Class 1, and Class 2 locations. Leakage surveys for offshore gas transmission and offshore gathering pipelines would not require the use of leak detection equipment. PHMSA has not proposed changes to the requirements for leakage surveys for gas transmission and gathering pipelines located outside of HCAs, or for gas transmission and gathering pipelines operating without an odor or odorant.

PHMSA also proposes more frequent leakage surveys for all valves, flanges, tie-ins with valves and flanges, ILI launcher and receiver facilities on gas transmission, offshore gathering, and Types A, B, and C gathering lines. PHMSA similarly proposes more frequent leakage surveys for those gas transmissions, offshore gathering, and Types A, B, and C gathering pipelines known to leak based on material, design, or past operating and maintenance history. Each such facilities identified in this paragraph located in Class 1, Class 2, and Class 3 locations must be surveyed twice each calendar year, and those in Class 4 locations must be surveyed at least four times each calendar year.

§ 192.723 Distribution: Leakage Surveys

PHMSA proposes defining minimum standards for leak survey practices and equipment on gas distribution pipelines through reference to the proposed ALDP performance standard in § 192.763. This proposal would replace the existing requirement at § 192.723 to use leak detection equipment and is described in more detail under the discussion of that section below.

PHMSA also proposes to increase the frequency of leakage surveys on most gas distribution pipelines outside of business districts to once every 3 calendar years, with an interval between surveys not to exceed 39 months. Operators whose procedures or DIMP call for more frequent leakage surveys would be obliged to conduct leakage surveys accordingly. And distribution pipelines outside of business districts at a high risk of leakage would generally be obliged to conduct leakage surveys more frequently: once each calendar year, with the interval between surveys not to exceed 15 months. The following distribution pipelines outside of business districts would be subject to PHMSA’s proposed new annual survey requirement:

²⁹⁵ EPA, “Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,” 87 FR 74702 (Dec. 6, 2022).

1. Cathodically unprotected pipelines on which electrical surveys are impracticable. This would typically cover bare and unprotected distribution lines;

2. Pipelines known to leak based on their material (including, but not limited to, cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history; and

3. Any distribution pipeline protected by a distributed anode system where the cathodic protection survey under § 195.463 showed a deficient reading during the most recent cathodic protection survey.

In determining whether a plastic pipeline is made of a “historic plastic with known issues” operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues from plastic pipe that is either comprised of particular materials; or manufactured at particular times, by particular companies, or pursuant to particular processes.

In addition to the above, PHMSA proposes to require, as soon as practicable following ground freezing, heavy rain, flooding, or other environmental conditions that may affect the venting of gas or cause gas migration to nearby buildings, reinvestigation of known leaks (including conducting a leakage survey for possible gas migration). This investigation is to determine whether changes to gas migration or to the facility itself have created a hazard that requires upgrading the leak. Generally, any surface freezing or frost and any flooding near the leak location is likely to affect gas venting and migration through the soil. When determining if heavy rain is likely to affect the venting or migration of leaking gas through the soil, operators should consider the estimated flow rate of the leak, rate of rainfall, local soil conditions, drainage, the presence of other nearby buried structures, and whether the area has a history of flooding.

PHMSA also proposes to require leakage surveys of a distribution pipeline soon (initiated within 72 hours) after the cessation of extreme weather events or land movement that could damage that pipeline segment. PHMSA defines the cessation of the event as either the time that the facility becomes safely accessible to operator personnel, or alternatively the time that the pipeline facility is placed back into service.

§ 192.727 Abandonment or Deactivation of Facilities

PHMSA proposes to revise § 192.727(b) and (c) governing abandonment of gas transmission, distribution, offshore gathering, and Type A gathering pipelines to provide that the existing exception for small gas purge volumes in those paragraphs would be available if purging would not create a risk to public safety specifically.

§ 192.751 Prevention of Accidental Ignition

PHMSA proposes to revise § 192.751(a) governing gas transmission, offshore gathering, and Type A gathering pipelines to clarify that the hazards being addressed in that provision are hazards to public safety specifically. PHMSA also proposes an editorial amendment clarifying that a fire extinguisher must be present, rather than provided, during venting of gas.

§ 192.760 Leak Grading and Repair

PHMSA proposes to create a new § 192.760 addressing requirements for grading and repairing leaks on gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines. The leak grading concept and many of the leak grading criteria are similar to those in the GPTC Guide, which has been adopted in some operator procedures and State pipeline safety requirements.

§ 192.760(a): General

Section 192.760(a) would require operators to have and carry out written procedures for grading and repairing leaks that meet or exceed the minimum requirements of § 192.760. PHMSA’s proposed requirements in this paragraph also clarify that § 192.760 would apply to any leak detected by the operator and applies to all components of pipelines (including, but not limited to, pipeline pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers). Operators must investigate any leaks discovered immediately and continuously until a leak grade determination has been made.

§ 192.760(b): Grade 1 Leaks

PHMSA proposes to characterize a grade 1 leak as an existing or probable hazard to persons and property or grave hazard to the environment. A grade 1 leak is an urgent or emergency situation and this NPRM proposes to require an operator take immediate and continuous action to eliminate any hazard to public safety and the environment and to promptly complete repair. PHMSA’s proposed paragraph (b)(2) includes a list

of actions the operator may take to address any hazard pending repair. These steps include activating the operator’s emergency plan under § 192.615, evacuating or blocking off the vicinity of the leak, rerouting traffic, eliminating ignition sources, ventilating the leak area to disperse hazardous accumulations of gas, stopping the flow of gas in the facility, or notifying emergency responders. While some of these actions, such as bar holing near the leak, may reduce gas concentration, proposed § 192.760(e) would not allow downgrading a leak to a lower-priority leak grade unless a repair has been made. The operator would have to promptly complete repair even if gas concentration falls to grade 2 or grade 3 levels after the leak location has been vented.

Paragraph (b)(1) provides minimum criteria for grade 1 leaks that would need to be included in operators’ leak grading procedures as they demonstrate that a leak poses an existing or probable hazard to public safety or grave hazard to the environment. Operator procedures may supplement those proposed minimum grade 1 criteria as desired. Specific criteria include the following: any leak that operating personnel at the scene determine is an existing or probable hazard to public safety or a grave hazard to the environment; any leak that has ignited; any indication of potential for ignition of accumulated gas resulting from gas migrating into a building, under a building, or into a tunnel; any indication of potential for ignition due to accumulated gas due to migration of gas to the outside wall of a building or to an area from which migration to the outside wall of a building could occur; gas concentration readings approaching LEL within either of a confined space or a substructure from which gas could migrate to the outside of a building; any leak that can be seen, heard, or felt; and any leak that is an incident pursuant to § 191.3.

§ 192.760(c): Grade 2 Leaks

PHMSA proposes to characterize a grade 2 leak as a leak with a probable future hazard to public safety or a significant hazard to the environment. There are currently no explicit Federal pipeline safety requirements to repair such leaks; however, some States and operators have adopted the GPTC Guide, which requires operators to repair such leaks within 12 months of detection. PHMSA proposes to require a grade 2 leak repair be completed within six months in most circumstances, however certain leaks would have shorter repair deadlines.

The proposed minimum criteria for grade 2 leaks reflect gas readings suggesting that a leak has a probable, future hazard to public safety or a significant hazard to the environment, but there is not an existing or probable hazard to public safety or a grave hazard to the environment as a grade 1 leak entails. Operator procedures may supplement those proposed minimum grade 2 criteria as desired. Among PHMSA's proposed minimum criteria are leaks, other than grade 1 leaks, producing a gas reading of 40% LEL or greater under a sidewalk in a wall-to-wall paved area, or a reading of 100% or greater under a street in a wall-to-wall paved area with gas migration that is not a grade 1 leak. Similar to the grade 1 criteria, the grade 2 criteria include criteria based on readings within confined spaces and substructures. A leak reading between 20% LEL and 80% of LEL in a confined space is a grade 2 leak. Unlike the grade 1 criteria, however, the grade 2 criteria make a distinction between gas readings in gas-associated and non-gas associated substructures. A leak must be classified as grade 2 if it produces a reading less than 80% LEL in a non-gas associated substructure from which gas could migrate. A leak with a reading of 80% LEL or greater in a gas associated substructure from which gas could migrate must be classified as a grade 2 leak. Like the grade 1 criteria, this NPRM proposes to require that operators' procedures allow operating personnel at the scene to decide that a leak justifies repair on a grade 2 schedule.

Similar to the discussion of grade 1 leaks, there are differences between the grade 2 criteria proposed in this NPRM and the grade 2 criteria in the GPTC Guide. To ensure timely repair of leaks with relatively large emissions, PHMSA proposes to require that any leak other than a grade 1 leak with a leakage rate of 10 CFH) or more be classified as a grade 2 leak. Additionally, in the NPRM, grade 2 is the minimum grade for any leak on a gas transmission pipeline or Type A or C gathering pipeline, or any leak of LPG or hydrogen that does not qualify as grade 1 leak.

PHMSA proposes to require that operators repair grade 2 leaks within 6 months of detection, or any alternative timeline identified in an operator's procedures or IM plan, whichever is earlier. Operators must reevaluate each grade 2 leak once every 30 days until the leak repair is completed or the leak is cleared (or, if a grade 2 leak must be repaired within 30 days, every 2 weeks until the repair has been completed). However, PHMSA proposes to require

operators to prioritize repair of some grade 2 leaks based on their higher potential for public safety and environmental consequences. For example, PHMSA proposes to require any leak on a gas transmission or Type A gathering pipeline, each in an HCA or a Class 3 or Class 4 location (and that is not a grade 1 leak) to be repaired within 30 days of detection, or the operator must take continuous action to monitor and repair the leak. Additionally, PHMSA proposes to require each operator's leak grading and repair procedures to include a methodology for prioritizing grade 2 leak repairs, including criteria for leaks that must be repaired within 30 days or less. The operator's methodology must include an analysis of the volume and migration of gas emissions, the proximity of gas to buildings and subsurface structures, the extent of pavement, and soil type and conditions that affect the possibility for gas migration such as frost conditions or soil moisture. This NPRM also proposes to require an operator complete repair of an existing grade 2 leak or take other immediate and continuous action to complete repairs and eliminate hazards when changing environmental conditions that may affect the venting or migration of gas that could allow gas to migrate to the outside wall of a building. Environmental changes that could contribute to gas migration include ground freezing, heavy rains or flooding, or the installation of new pavement.

Finally, PHMSA proposes to require that operators complete repairs of grade 2 leaks known to exist on or before the effective date of the rule within 1 year from the date of publication of the final rule.

§ 192.760(d): Grade 3 Leaks

PHMSA proposes to characterize a grade 3 leak as any leak that does not meet its minimum proposed grade 1 or grade 2 criteria. Like grade 2 leaks, there is no current Federal standard requiring repair of such leaks, and the GPTC Guide does not require a minimum repair schedule. Illustrative examples of grade 3 leaks as contemplated by this NPRM include (but are not limited to) leaks with a reading of less than 80% LEL in gas-associated substructures from which gas is unlikely to migrate, any reading of gas under pavement outside of wall-to-wall paved areas where it is unlikely that gas could migrate to the outside wall of a building, or a reading of less than 20% LEL in a confined space.

PHMSA proposes to require an operator to complete repair of each grade 3 leak within 24 months of the

date the leak was detected and require each grade 3 leak be re-evaluated once every six months until the leak repair has been completed. However, PHMSA proposes to allow an operator to continue to monitor a grade 3 leak provided the pipeline segment containing the leak is scheduled for replacement and is in fact replaced, within five years of the date the leak was detected. Finally, PHMSA proposes to require a grade 3 leak known to exist on or before the effective date of the rule be repaired within 3 years from the date of publication of the final rule, unless the pipeline is scheduled for replacement within five years from the effective date of the rule.

§ 192.760(e): Post-Repair Inspection

PHMSA in proposed § 192.760(e) defines requirements for determining and documenting that a complete and effective repair of a leak has been accomplished. PHMSA proposes to require that, in order for a leak repair to be complete, an operator must perform a permanent repair and obtain, during a post-repair inspection, a gas concentration reading of 0% gas at the leak location. A temporary repair may be used to downgrade a leak in accordance with proposed § 192.760(g). Proposed § 192.760(e)(2) would require that the first post-repair inspection be completed no sooner than 14 days but no later than 30 days after the date of repair.

Proposed § 192.760(e)(3) provides for enhanced repair and monitoring requirements if a post-repair inspection yields a gas reading greater than 0% gas. Specifically, if a post-repair inspection indicates that a grade 1 or 2 condition exists, the operator would need to reevaluate the repair and take immediate and continuous action to eliminate the hazard and complete the repair. If a grade 1 or grade 2 condition did not exist, the operator would need both to re-inspect the leak every 30 days and complete the repair within either of the repair deadline for a grade 3 leak under § 192.760(d)(2) or (for a leak that was downgraded after the initial repair) a new repair deadline established under § 192.760(g). Lastly, proposed § 192.760(e)(4) would provide that post-repair inspection would not be necessary if leak remediation was completed via routine maintenance activities such as cleaning, lubrication, or adjustment.

§ 192.760(f) and (g): Upgrading and Downgrading

Proposed § 192.760(f) and (g) describe the repair deadlines and requirements for leaks that are upgraded or

downgraded to higher or lower -priority grades. Operators who receive information that a higher-priority grade condition exists on a previously graded leak would need to upgrade that leak to a higher-priority grade. For a leak that is upgraded, PHMSA proposes to require that the deadline for the repair would be the earlier of either the remaining time based on the original leak grade, or the time allowed for repair for the upgraded leak measured from the time the operator receives information that a higher-priority grade condition exists. In other words, an operator would not be permitted to extend the repair deadline by upgrading a leak.

PHMSA also proposes to prohibit downgrading of a leak unless a temporary repair has been made or a permanent repair to the pipeline has been attempted but gas was detected during the post-repair inspection required by proposed § 192.760(e). For example, a leak may not be downgraded simply by venting the leak location until gas measurements fall to grade 3 levels, with no action taken to permanently remediate the leak. A leak may be downgraded if the facility was the subject of an attempt at permanent repair, but a non-zero reading was measured during the post-repair inspection described in the discussion of § 192.760(e). If a leak were downgraded after the attempted permanent repair, the time period for completion of repair would be the remaining time allowed for repair under its new grade, measured from the time the leak was initially detected.

§ 192.760(h) Extension of Leak Repair

PHMSA proposes to allow an extension of the repair deadline requirements for individual grade 3 leaks only on a case-by-case basis. This extension requires notification to, and review by, PHMSA pursuant to the procedures in § 192.18. An operator may request an extension if the delayed repair timeline would not result in increased risks to public safety, and the operator can demonstrate either that the prescribed repair schedule is impracticable, an alternative repair schedule is necessary for safety, or remediation within the specified time frame would result in the release of more gas to the environment than would otherwise occur if the leak were allowed to continue. For example, if the repair of a grade 3 leak would require significant emissions to blowdown the facility, delaying repair to coordinate with other maintenance requiring shutdown (and thereby minimizing the total number of blowdowns) may be

appropriate. PHMSA proposes to require that a notification under this paragraph include descriptions of the leak, the leaking facility, the leak environment, the proposed extended repair schedule, the justification for an extended repair schedule and proposed emissions mitigation methods.

§ 192.760(i): Recordkeeping

Proposed § 192.760(i) describes recordkeeping requirements associated with leak grading and repair. Beginning on the effective date of the rule, PHMSA proposes that records documenting the complete history of investigation and grading of each leak prior to completion of the repair would need to be retained until five years after the date of the final post-repair inspection performed under proposed paragraph § 192.760(e). These records include documentation of grading monitoring, inspections, upgrades, and downgrades. PHMSA also proposes that records associated with the detection, remediation, and repair of each leak must be maintained for the life of the pipeline. Permanent recordkeeping would apply to both piping and non-piping portions of the pipeline. Complete records of the location and timing of leaks and repairs is necessary for an adequate leak management program.

§ 192.763 Advanced Leak Detection Program

PHMSA proposes to create § 192.763 that would require operators of gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines establish a written Advanced Leak Detection Program (ALDP) and establish performance standards for both the sensitivity of leak detection equipment and for the effectiveness of operators' ALDPs. The ALDP represents a comprehensive set of technologies and procedures that an operator would use to detect all leaks consistent with the proposed ALDP performance standard at § 192.763(b). PHMSA proposes to require that an operator's written ALDP include four main elements: leak detection equipment, leak detection procedures, prescribed leakage survey frequencies, and program evaluation.

The first element in an ALDP is the leak detection equipment that operators would use to perform leakage surveys, pinpoint leak locations, and investigate leaks. These equipment requirements are proposed in § 192.763(a)(1). Operator ALDPs would include a list of leak detection technologies that the operator would use for leakage surveys, pinpointing leak location, and leak investigations. Leak detection

equipment is not required for surveys of offshore gas transmission and offshore gathering pipelines because offshore leaks are visibly conspicuous. PHMSA further proposes that any leak detection equipment must have a minimum sensitivity of 5 ppm (§ 192.763(a)(1)(ii)) to ensure detection of leaks consistent with the proposed ALDP performance standard at § 192.763(b). An operator may need to use more sensitive equipment than required by § 192.763(a)(1)(ii)—or supplemental equipment or techniques (e.g., soap bubble testing)—to meet that ALDP performance standard depending on the leak detection procedures used and the operating characteristics and environment of the pipeline. Alternatively, operators of each of (1) natural gas transmission and part 192-regulated gathering pipelines, each of which are located either offshore or in Class 1 or 2 locations, and (2) any gas pipeline transporting flammable, toxic, or corrosive gas other than natural gas, may (pursuant to § 192.763(c)) request use of alternative leak detection equipment by submitting a § 192.18 notification for PHMSA review.

PHMSA proposes to require operators select leak detection equipment within their ALDPs based on a documented analysis that reflects the state of commercially available advanced leak detection technologies and practices, and considers at a minimum the size, configuration, operating parameters, and operating environment of the operator's system (§ 192.763(a)(1)(iii)). PHMSA further proposes an operator's analysis consider the appropriateness of specified examples of possible advanced leak detection technologies, including each of the following: handheld equipment, including optical, infrared, or laser-based devices; continuous monitoring via stationary gas detectors, pressure monitoring or other means; mobile surveys from vehicle or aerial platforms; or systemic use of any other commercially available advanced technology capable of meeting the program performance standard in § 192.763(b).

The second program element in proposed § 192.763(a)(2) consists of the operator's written procedures related to leak detection. PHMSA proposes that, at a minimum, the ALDP must include procedures for performing compliant leakage surveys for each of the leak detection equipment included in an operator's ALDP. To ensure that operators use procedures appropriate for environmental conditions such as temperature, wind, time of day, precipitation and humidity, the operator must define under which conditions the

procedure may and may not be used. Additionally, those procedures must be consistent with any instructions of the leak detection equipment manufacturer regarding environmental and operational conditions parameters for use.

PHMSA proposes to require that an operator's procedures must provide for pinpointing the location of all leak indications with the use of handheld leak detection equipment (§ 192.763(a)(2)(ii)). As described above, any equipment used for pinpointing leaks must generally (for onshore gas transmission, Types A, B, and C gathering, and distribution pipelines) have a minimum sensitivity of 5 ppm or less. If a leak location was pinpointed with handheld leak detection equipment meeting this standard during the initial survey, PHMSA would not expect an operator to re-survey the area to meet the requirement of this paragraph.

To ensure the quality of leak detection equipment, PHMSA also proposes at § 192.763(a)(2)(iii) to require that an operator have procedures for validating that a leak detection device used in its ALDP meets the 5-ppm sensitivity requirement in § 192.763(a)(1)(ii) prior to initial use. This consists of testing the equipment measurements against a known concentration of gas. The operator must maintain records that the leak detection equipment has been validated for five years after the date that the device ceases to be used in the operator's ALDP. Separate from the one-time validation requirement, PHMSA also proposes to require that operators have procedures for the maintenance and calibration of leak detection equipment (§ 192.763(a)(2)(iv)). At a minimum the operator must follow the maintenance and calibration procedures recommended by the equipment manufacturer. PHMSA further proposes to require that an operator recalibrate leak detection equipment following an indication of malfunction.

The third required element of an ALDP in proposed § 192.763(a)(3) is the frequency of leakage surveys. As discussed above, PHMSA proposes to define minimum leakage survey frequencies in § 192.723 for gas distribution pipelines and in § 192.706 for gas transmission, offshore gathering, and Types A, B, and C gathering pipelines. However, PHMSA also proposes that if more frequent leakage surveys are necessary to meet the ALDP performance standard in proposed § 192.763(b) or otherwise specified by the operator, those frequencies must be noted in the operator's ALDP. More frequent leakage surveys may be

required for less sensitive leak detection equipment, challenging survey conditions, or facilities with a high leakage frequency.

The final element of an ALDP consists of proposed requirements in § 192.763(a)(4) for operator procedures governing program evaluation and improvement. At least annually, operators must re-evaluate the elements of their ALDP considering, at a minimum, each of the following: the performance of leak detection equipment used, advances in leak detection technologies and practices, the number of leaks initially detected by third parties, the number of leaks and incidents overall, and estimated emissions from leaks. This is similar in principle to the existing continuous improvement requirements under IM requirements in part 192, subparts O and P, as well as requirements for certain operators to periodically review procedures under § 192.605(b)(8) and (c)(4). If an operator finds evidence that their ALDP fails to detect leaks during leakage surveys as required by the ALDP performance standard at § 192.763(b), it must make changes to program elements to ensure that the minimum performance standard in § 192.763(b) is met. Operators must consider ways to improve their leak detection programs based on leak detection performance data and advances in technology.

PHMSA's proposed ALDP performance standard at § 192.763(b) includes a holistic, program-wide performance standard for the ALDP elements listed in § 192.763(a). PHMSA proposes to require that an ALDP for gas transmission, distribution, offshore gathering, and Types A, B, and C gathering pipelines must be capable of detecting all leaks that produce a reading of 5 ppm of gas or greater when measured from a distance of 5 feet from the pipeline, or from within a wall-to-wall paved area. The performance standard of detecting leaks of a size large enough to produce a reading of 5 ppm is a measurement of minimum detectible leak size rather than the sensitivity of equipment itself. PHMSA further proposes that each ALDP must be validated and documented with engineering tests and analyses, and that such records should be maintained for five years after the date that ALDP is no longer used by the operator.

Lastly, PHMSA proposes at § 192.763(c) the ability for certain operators (specifically, each of (1) natural gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or 2 locations and (2) any gas pipeline transporting flammable, toxic, or

corrosive gas other than natural gas) to request use of an alternative performance standard, pursuant to the notification and PHMSA review procedures established in § 192.18. PHMSA proposes to require that any notifications submitted under this provision must include, among other things, information about the location, design, gas being transported, operational parameters, environmental conditions, and material properties and history of the pipeline, the proposed alternative performance standard, and a description of any leak detection equipment and procedures that would be used.

§ 192.769 Qualification of Leakage Survey, Investigation, and Grading Personnel

PHMSA proposes to clarify at § 192.769 training and qualification requirements for personnel that conduct leakage surveys, investigation, and leak grading on gas transmission, distribution, offshore gathering, and Types A gathering pipelines. Section 192.769 proposes to require that all such personnel must be qualified under subpart N and have documented work history or training in conducting leakage surveys, investigation, and grading. This requirement clarifies that surveying, investigating, grading, and repairing leaks are covered tasks under subpart N.

§ 192.770 Minimizing Emissions From Gas Transmission Pipeline Blowdowns

PHMSA in a new § 192.770 proposes to require gas transmission, offshore gathering, and Type A gathering pipeline operators minimize the release of gas to the environment from intentional, vented emissions (including for repairs, construction, operations, or maintenance). PHMSA does not, however, propose to require mitigation for emergency releases (e.g., emergency blowdowns) associated with the activation of an operator's emergency plan under § 192.615(a)(3). However, an operator must document when an emergency release occurs, and the justification for not taking mitigative action.

The proposed regulatory text provides examples of approved mitigation methods from which pertinent operators may choose to prevent or mitigate vented emissions. The first method is installing and using valves or control fittings to reduce the volume of gas that must be removed from the pipeline. The second method listed is routing vented gas to a flare stack to be ignited or to other equipment for consumption. The third, fourth, and fifth methods each involve reducing the pressure of a

pipeline segment prior to venting, reducing total emissions volume. In the third example, an operator isolates the pipeline segment upstream of the venting segment and uses the downstream compressor station to reduce the pressure of the affected segment. The fourth example is similar except instead of the compressor station, an operator uses a mobile compressor unit to reduce the pressure of the venting segment by compressing gas into adjacent facilities or a storage vessel. The fifth example is like the fourth, except it may be performed without compression. PHMSA also proposes that operators may request, pursuant to the notification procedure at § 192.18, use of alternative approaches for mitigating vented emissions not listed in the proposed regulatory text, but which would provide reduce emissions by at least 50% compared with venting gas to the atmosphere without mitigative action.

Lastly, PHMSA proposes that operators document the methodology used in their procedures, including by documenting an analysis on how its selected method minimizes the release of natural gas to the environment.

§ 192.773 Pressure Relief Device Maintenance and Adjustment of Configuration

PHMSA in a new § 192.773 proposes to require operators of all gas distribution, transmission, offshore gathering, and Types A, B, and C gathering pipelines to have written operating and maintenance procedures for assessment of the proper function of pressure relief devices. PHMSA's proposed regulatory text would require operators to assess and either repair or replace malfunctioning pressure relief devices. PHMSA's proposed language also identifies specific action operators would have to take on operation of a malfunctioning pressure relief device, to include immediate repair or replacement of relief devices that fail to provide adequate overpressure protection. If a relief device activates and releases gas below the set pressure ranges defined in the operator's operations and maintenance manual, the operator must take immediate and continuous action to stop further releases of gas and ensure adequate overpressure protection. In the latter case, the device must be repaired or replaced as soon as practicable but within 30 days of actuation. PHMSA further notes that operators would be obliged to maintain records documenting the proper operation and any remediation/replacement of

pressure relief devices for the service life of their facilities.

§ 192.1007 What are the required elements of an integrity management plan?

PHMSA proposes to revise § 192.1007(e)(1)(i) and (v) to delete existing references to § 192.703(c) that would be rendered inapposite by PHMSA's proposed adoption of a different meaning for "hazardous leak" applicable to § 192.703(c) than would be applicable within its integrity management regulations at subparts O and P.

§ 193.2503 Operating Procedures

Section 193.2503(c) obliges operators of part 193-regulated LNG facilities to have and follow written procedures for normal and abnormal operations. PHMSA proposes to revise the regulatory language in this provision to incorporate within its regulations the section 114 of the PIPES Act of 2020 self-executing mandate that operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities.

§ 193.2523 Minimizing Emissions From Blowdowns and Boiloff

PHMSA proposes to add a new § 193.2523 to require operators of part 193-regulated LNG facilities to mitigate methane emissions from non-emergency, vented releases such as blowdowns and tank boiloff. PHMSA's proposed mitigation and documentation requirements in § 193.2523 largely mirror those described in the section V discussion of proposed § 192.770.

§ 193.2605 Maintenance Procedures

Section 193.2605(b) obliges operators of part 193-regulated LNG facilities to have and follow written maintenance procedures. PHMSA proposes to revise the regulatory language in this provision to incorporate within its regulations the section 114 of the PIPES Act of 2020 self-executing mandate that operators update their procedures to provide for the elimination of leaks and minimize release of gas from pipeline facilities.

§ 193.2624 Leakage Surveys

PHMSA proposes to create a new section requiring operators of LNG facilities to perform periodic methane leakage surveys on methane or LNG-containing components and equipment at least four times each calendar year, with a maximum interval between surveys not to exceed 4½ months. This requirement would apply to part 193-regulated LNG facilities. The methane leakage surveys would need to be

performed with leak detection equipment satisfying the 5-ppm minimum sensitivity standard proposed for part 192-regulated gas pipelines elsewhere in this NPRM. Methane leaks and other conditions discovered during the surveys would need to be remediated in accordance with the operators' maintenance or abnormal operating conditions procedures, to include any repair schedules within those procedures. Leakage survey records, including records of equipment validation and calibration, must be maintained for 5 years after the leakage survey is completed.

VI. Regulatory Analysis and Notices

A. Legal Authority for This Rulemaking

This proposed rule is published under the authority of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are those set forth in the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*) (authorizing, *inter alia*, issuance of regulations governing design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities) and section 28 of the Mineral Leasing Act, as amended (30 U.S.C. 185(w)(3)). For a complete listing of authorities, *see* 49 CFR 1.97.

This NPRM proposes to implement several provisions of the PIPES Act of 2020, including sections 113 (codified at 49 U.S.C. 60102(q)), 114 (codified at 49 U.S.C. 60108(a)), and 118 (codified at 49 U.S.C. 60102(b)(5)). While section 113 of the PIPES Act of 2020 does not mandate that PHMSA issue leak detection and repair program requirements for Type C gas gathering pipelines in Class 1 locations, 49 U.S.C. 60101(b) and 60102 grant authorities to issue standards for the transportation of gas via any part 192-regulated gathering pipelines to protect public safety and the environment, which include Type C gas gathering pipelines. As explained in section II.E of this NPRM, fugitive emissions from all gas gathering pipelines (including Type C gas gathering pipelines in Class 1 locations) are a significant source of methane emissions which directly harm the environment by contributing to climate change—which (as explained in section II.B of this NPRM) itself entails public safety and environmental risks. Further, as explained in section II.D.3 of this NPRM and discussed in further detail in the Preliminary RIA, releases of natural gas (particularly unprocessed natural

gas from Type C and other gas gathering pipelines) contain HAPs and VOCs are particularly harmful to public safety and the environment.

Further, 49 U.S.C. 60117(c) authorizes PHMSA to require owners and operators of gas gathering, transmission, and distribution pipelines and other pipeline facilities to submit information (including, as appropriate, each of annual reports, incident reports, and intentional release reports, and NPMS information as proposed in this NPRM) required for regulation of those pipeline facilities under the Federal Pipeline Safety Statutes. Further, section 60117(c) authorizes the Secretary to require owners and operators of Type R gas gathering pipelines to submit the same information to support future decision making regarding whether and to what extent to impose requirements in 49 CFR part 192 on those gas gathering pipelines.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

E.O. 12866 (“Regulatory Planning and Review”),²⁹⁶ as amended by E.O. 14094 (“Modernizing Regulatory Review”),²⁹⁷ requires that agencies “should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.” Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, E.O. 12866 requires that “agencies should select those [regulatory] approaches that maximize net benefits (including potential

economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.” Similarly, DOT Order 2100.6A (“Rulemaking and Guidance Procedures”) requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

E.O. 12866, as amended, and DOT Order 2100.6A require that PHMSA submit “significant regulatory actions” to the Office of Management and Budget (OMB) for review. This action has been determined to be significant under E.O. 12866, as amended. It is also considered significant under DOT Order 2100.6A because of significant congressional, State, industry, and public interest in pipeline safety. The proposed rule has been reviewed by OMB in accordance with E.O. 12866 and is consistent with the requirements of E.O. 12866, as amended, and DOT Order 2100.6A.

E.O. 12866, as amended, and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 *et seq.*). In accord with the requirement, PHMSA seeks public comment on the proposals in the NPRM (including preliminary cost and cost

savings analyses pertaining to those proposals set forth in the preliminary RIA, as well as discussions of the public safety, environmental, and equity benefits in that document and the draft Environmental Assessment), as well as any information that could assist in evaluating the benefits and costs of this NPRM.²⁹⁸

The quantified benefits of the final rule consist of the climate benefits of avoided methane emissions and the market value of avoided natural gas losses. PHMSA expects additional, unquantified benefits including safety benefits from early detection of leaks before they can evolve into incidents and detection of integrity threats on gas transmission and gathering pipelines from right-of-way patrols. PHMSA also expects additional unquantified environmental and public health benefits associated with preventing releases of natural gas, and other flammable, toxic or corrosive gases, and expects these benefits to be important given the types of health effects resulting from exposure to air pollutants (e.g., asthma and other respiratory effects, cancer). PHMSA invites commenters to provide additional information that would enable quantification of the additional health and safety benefits of the rule.

The table below summarizes the annualized quantified costs and benefits for the provisions in the final rule at a 3 percent and a 7 percent discount rate (discussed in further detail in the Preliminary RIA for this NPRM, available in the rulemaking docket):

ANNUALIZED MONETIZED COSTS AND BENEFITS

[Million 2020\$]

Discount rate (%)	Item	Gathering	Transmission	Distribution		Total ¹	
				Lamb <i>et al.</i> (2015)	Weller <i>et al.</i> (2020)	Low	High
3	Benefits	\$553	\$12	\$515	\$1,754	\$1,081	\$2,320
	Costs	211	15	514	654	740	880
	Net benefits	343	–3	1	1,100	341	1,440
7% ²	Benefits	549	12	512	1,743	1,073	2,304
	Costs	209	15	530	677	753	900
	Net benefits	340	–3	–18	1,067	320	1,404

¹ Total costs and benefits are presented as a range to reflect different assumptions regarding leak incidence and methane emissions rate across pipe materials. The low estimate reflects distribution costs based on Lamb *et al.* (2015) whereas the high estimate reflects distribution costs based on Weller *et al.* (2020).

² Costs and benefits of natural gas losses are discounted at 7 percent, whereas climate benefits are based on the average SC–CH₄ at 3 percent discount. See section 5 of the Preliminary RIA for estimated climate benefits using other discount rates.

Source: PHMSA analysis.

Benefits of the final rule would depend on, among other things, the

degree to which compliance actions result in additional safety and gas

release avoidance and mitigation measures, relative to the baseline, and

²⁹⁶ 58 FR 51735 (Oct. 4, 1993).

²⁹⁷ 88 FR 21879 (April 11, 2023).

²⁹⁸ PHMSA also participated in OMB-led E.O. 12866 meetings requested by public stakeholders during interagency regulatory review of this NPRM, including EDF (March 9, 2023), PST (March 17,

2023), and Boundary Stone Partners/Aclima, Inc. (March 20, 2023). Summaries of each E.O. 12866 meeting are available in the rulemaking docket at Doc. No. PHMSA–2021–0039.

the effectiveness of these measures in preventing or mitigating future releases or incidents from gas pipeline facilities subject to this NPRM.

C. Executive Order 13132: Federalism

PHMSA analyzed this NPRM in accordance with the principles and criteria contained in E.O. 13132 (“Federalism”) ²⁹⁹ and the Presidential Memorandum (“Preemption”) published in the **Federal Register** on May 22, 2009.³⁰⁰ E.O. 13132 requires agencies to assure meaningful and timely input by State and local officials in the development of regulatory policies that may 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.”

This NPRM is not expected to have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This NPRM is not expected to impose substantial direct compliance costs on State and local governments.

While the NPRM may operate to preempt some State requirements, it would not impose any regulation that has substantial direct effects on the States, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. Section 60104(c) of Federal Pipeline Safety Laws prohibits certain State safety regulation of interstate pipelines. Under Federal Pipeline Safety Laws, States that have submitted a current certification under section 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate. In this instance, the preemptive effect of the regulatory amendments in this NPRM would be limited to the minimum level necessary to achieve the objectives of the Federal Pipeline Safety Laws. Therefore, the consultation and funding requirements of E.O. 13132 do not apply.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires Federal agencies to conduct an initial Regulatory Flexibility Analysis (IRFA) for a proposed rule subject to notice-and-comment rulemaking under the APA unless the agency head certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities. E.O. 13272 (“Proper Consideration of Small Entities in Agency Rulemaking”) ³⁰¹ obliges agencies to establish procedures promoting compliance with the Regulatory Flexibility Act. The DOT posts its implementing guidance on a dedicated web page.³⁰² This NPRM was developed in accordance with E.O. 13272 and DOT guidance to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities has been properly considered.

PHMSA conducted an IRFA, which has been made available in the docket within the Preliminary RIA for this rulemaking. PHMSA has preliminarily determined that the proposed rule could result in a significant economic impact on a substantial number of small entities, depending on the degree to which operators are able to pass-through costs. PHMSA seeks comment on whether the proposed rule, if adopted, would have a significant economic impact on a significant number of small entities.

E. National Environmental Policy Act

The National Environmental Policy Act (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to consider the consequences of major Federal actions and prepare a detailed statement on actions significantly affecting the quality of the human environment. The Council on Environmental Quality implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (“Procedures for Considering Environmental Impacts”) establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

³⁰¹ 67 FR 53461 (Aug. 16, 2002).

³⁰² DOT, “Rulemaking Requirements Related to Small Entities,” <https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities> (last accessed June 17, 2021).

PHMSA analyzed this NPRM in accordance with NEPA, NEPA implementing regulations, and DOT Order 5610.1C. PHMSA has prepared a draft environmental assessment (DEA) and preliminarily determined this action will not significantly affect the quality of the human environment. To the extent that the NPRM has impacts on the environment, these are primarily beneficial ecological and human health impacts from early detection of gas leaks and minimizing emissions of methane, a powerful GHG that contributes to climate change. A copy of the draft EA for this action is available in the docket. PHMSA invites comment on the environmental impacts of this NPRM.

F. Environmental Justice

E.O. 12898 (“Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations”),³⁰³ as supplemented by the E.O. entitled “Revitalizing Our Nation’s Commitment to Environmental Justice for All” (April 21, 2023),³⁰⁴ directs Federal agencies to take appropriate and necessary steps to identify and address disproportionately high and adverse effects of Federal actions on the health or environment of minority and low-income populations “[t]o the greatest extent practicable and permitted by law.” DOT Order 5610.2C (“U.S. Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations”) establishes departmental procedures for effectuating E.O. 12898 promoting the principles of environmental justice through full consideration of environmental justice principles throughout planning and decision-making processes in the development of programs, policies, and activities, including PHMSA rulemaking.

PHMSA has evaluated this NPRM under DOT Order 5610.2C and E.O. 12898 and has preliminarily determined it will not cause disproportionately high and adverse human health and environmental effects on minority and low-income populations. The NPRM is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor

³⁰³ 59 FR 7629 (Feb. 16, 1994).

³⁰⁴ E.O. number and **Federal Register** citation forthcoming. See White House, “Executive Order on Revitalizing Our Nation’s Commitment to Environmental Justice for All” (April 21, 2023), <https://www.whitehouse.gov/briefing-room/presidential-actions/2023/04/21/executive-order-on-revitalizing-our-nations-commitment-to-environmental-justice-for-all/#:~:text=We%20must%20advance%20environmental%20justice,human%20health%20and%20the%20environment.>

²⁹⁹ 64 FR 43255 (Aug. 10, 1999).

³⁰⁰ 74 FR 24693 (May 22, 2009).

is it expected to adversely impact any particular population, region, or community. And insofar as PHMSA expects the rulemaking would reduce the safety and environmental risks associated with gas gathering, transmission, and distribution lines, many of which are located in the vicinity of environmental justice communities,³⁰⁵ PHMSA does not expect the regulatory amendments introduced by this final rule would entail disproportionately high adverse risks for minority or low-income populations in the vicinity of those pipelines. Lastly, as explained in the draft environmental assessment, PHMSA expects that its proposed regulatory amendments will yield GHG emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority and low-income populations.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this NPRM according to the principles and criteria in E.O. 13175 (“Consultation and Coordination with Indian Tribal Governments”) ³⁰⁶ and DOT Order 5301.1 (“Department of Transportation Programs, Policies, and Procedures Affecting American Indians, Alaska Natives, and Tribes”). E.O. 13175 requires agencies to assure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing “substantial direct compliance costs” or “substantial direct effects” on such communities or the relationship and distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the NPRM and has preliminarily determined that it will not significantly or uniquely affect Tribal communities or Indian Tribal governments. The rulemaking’s regulatory amendments are facially neutral and would have broad, national scope; PHMSA, therefore, does not expect this NPRM to significantly or uniquely affect Tribal communities, much less impose substantial compliance costs on Native American Tribal governments or

mandate Tribal action. Insofar as PHMSA expects the rulemaking will improve safety and reduce public safety and environmental risks associated with gas pipelines, PHMSA believes it will not entail disproportionately high adverse risks for Tribal communities. While PHMSA is not aware of specific Tribal-owned business entities that operate part 192-regulated gas pipelines, any such business entities could be subject to direct compliance costs as a result of this proposed rule. Because PHMSA does not anticipate that this proposed rule would have tribal implications, the funding and consultation requirements of E.O. 13175 would not apply. PHMSA seeks comment on the applicability of E.O. 13175 to this proposed rule and the existence of any Tribal-owned business entities operating pipelines affected by the proposed rule (along with the extent of such potential impacts).

H. Executive Order 13211

E.O. 13211 (“Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use”) ³⁰⁷ requires Federal agencies to prepare a Statement of Energy Effects for any “significant energy action.” E.O. 13211 defines a “significant energy action” as any action by an agency (normally published in the **Federal Register**) that promulgates, or is expected to lead to the promulgation of, a final rule or regulation (including a notice of inquiry, ANPRM, and NPRM) that (1)(i) is a significant regulatory action under E.O. 12866 or any successor order and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This NPRM is a significant action under E.O. 12866, as amended; however, it is not likely to have a significant adverse effect on supply, distribution, or energy use, as further discussed in the Preliminary RIA. Further, OIRA has not designated this NPRM as a significant energy action.

I. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. The proposals in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM would trigger new reporting and notification requirements for operators of natural gas

transmission, distribution, and gathering pipelines. PHMSA proposes new and revised reporting requirements intended to improve the quality of the data available concerning pipeline leaks and other sources of emissions.

Reporting Releases of Gas

PHMSA proposes to require pipeline operators to submit data on intentional and unintentional releases of gas with a volume of 1 MMCF or greater excluding certain events that had been reported as incidents under §§ 191.9 or 191.15. To collect this data, PHMSA proposes the creation of a new large-volume emissions report to parallel existing incident reporting requirements. Operators would be required to submit this data upon each occurrence of a release that meets the reporting requirement within 30 days from the date of detection or 30 days from the date that a previously detected release became reportable. These new large-volume gas release reports would provide valuable information on the primary sources and causes of vented emissions and the causes of large-volume leaks that do not qualify as incidents. This data would address information gaps in the current incident reporting requirements with respect to intentional releases and environmentally hazardous unintentional releases with release volumes between 1 MMCF and 3 MMCF. PHMSA estimates that it would receive 373 reports on average each year (239 and 134 reports for gathering and transmission, respectively), with each report estimated to require 4 hours to prepare.

Annual Report Revisions

PHMSA also proposes revisions to the existing gas transmission, gathering, and distribution annual report forms to include reporting of leaks discovered and repaired by grade, estimated leak emissions by grade, and estimated annual emissions from other sources by source category. Currently, these forms include data on leak repair, however they lack data on leaks discovered and data on emissions generally.

Safety-Related Condition Reporting

PHMSA proposes an exception from § 191.23 safety-related condition reporting requirements for events that are reported as large-volume gas releases. The proposed exception for large-volume incident reports would be consistent with the existing exception at § 191.23(b) for events reported as incidents. Because large-volume gas release reports would have roughly equivalent detail to an incident report,

³⁰⁵ See Ryan Emmanuel, et al., “Natural Gas Gathering and Transmission Pipelines and Social Vulnerability in the United States,” 5:6 GeoHealth (June 2021), <https://agupubs.onlinelibrary.wiley.com/doi/10.1029/2021JG006156> (concluding that natural gas gathering and transmission infrastructure is disproportionately sited in socially-vulnerable communities).

³⁰⁶ 65 FR 67249 (Nov. 9, 2000).

³⁰⁷ 66 FR 28355 (May 22, 2001).

a less detailed safety-related condition report would not be necessary. PHMSA expects the burden for this information collection to decrease because of this change.

National Pipeline Mapping System Reporting

This NPRM proposes to extend the reporting requirements at § 191.29 for the NPMS to offshore gathering pipelines as well as Types A, B, and C regulated onshore gas gathering pipelines. Currently only gas transmission pipelines are required to provide geospatial data on their pipeline systems in accordance with the NPMS requirements at 49 U.S.C. 60132 and 49 CFR 191.29. The collection of geospatial data from gas gathering pipelines would provide PHMSA critical knowledge about the location and operating characteristics of these pipelines to assist in the identification and remediation of leaks.

Notification Requirements

PHMSA requires operators to make notifications in accordance with § 192.18 90 days in advance of using an alternative technology or assessment method. Operators may proceed only if they do not receive a letter objecting to the proposed use of other technology and/or methods.

PHMSA proposes, in § 192.706(a), to allow operators to request the use of human senses, in lieu of leak detection equipment, when conducting a leak survey if the operator provides advance notification to PHMSA in accordance with § 192.18.

In § 192.763(c), PHMSA proposes to allow operators to request to use an alternative advanced leak detection performance standard if the operator notifies PHMSA, in accordance with § 192.18. For gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or Class 2 locations, an operator may use an alternative performance standard with prior notification to, and review by PHMSA in accordance with § 192.18. The notification must include: mileage by system type, known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications, including coating, cathodic protection status, and pipe welding or joining method, the proposed performance standard, any safety conditions such as increased survey frequency, the leak detection equipment, procedures, and leakage survey frequencies the operator proposes to employ, data on the sensitivity and the leak detection performance of the proposed alternative

ALDP standard, and the gas transported by the pipeline.

In this proposed rule, an operator may request an extension of the leak repair deadline requirements for an individual grade 3 leak with advance notification to, and review by, PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, or that remediation within the specified time frame would result in the release of more gas to the environment than would occur with continued monitoring. The notification must include: a description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure; a description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement; a description of the alternative repair schedule and a justification for the same; and proposed emissions mitigation methods and monitoring and repair schedule. PHMSA estimates that it may receive 508 requests to extend the deadline for remedying leaks on average per year (341 from gas gathering operators and 167 from gas transmission operators), and that each of these requests would require approximately 8 hours to prepare.

Recordkeeping Requirements

PHMSA proposes to require operators to develop and maintain various records in conjunction with the proposed requirements in this NPRM. Among those requirements, operators must develop written procedures for grading and repairing leaks according to § 192.760(a)(1); operators must document post-repair evaluations according to § 192.760(e); operators must record the history of each leak, including leak discovery, grading, monitoring, remediation, upgrades, and downgrades, and maintain these records for a period of 5 years (records of repairs must be maintained for the life of the pipeline) pursuant to § 192.760(i)(1) and (2); operators must document the leak detection equipment choice analysis required in § 192.763(f); operators must also record leak detection equipment calibration (and re-calibration) and maintain these records for the life of the equipment pursuant to § 192.763(h)(2); and operators must record the repair or replacement of a pressure relief device

and maintain these records for the life of the pipeline according to § 192.773(c). PHMSA estimates that it would take operators, on average, 80 hours annually to develop these records. PHMSA estimates that it would take operators 20 hours annually to maintain these records. This burden would be incurred by the total reporting community.

PHMSA will submit the following information collection requests to OMB for approval based on the requirements in this proposed rule. These information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden for the following information collections are estimated to be revised as follows:

1. *Title:* Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137-0522.

Current Expiration Date: 03/31/2025.

Abstract: This mandatory information collection covers the collection of data from operators of natural gas pipelines, UNGSFs, and LNG facilities for annual reports. 49 CFR 191.17 requires operators of UNGSFs, gas transmission systems, and gas gathering systems to submit an annual report by March 15, for the preceding calendar year. This information collection also covers the collection of immediate notice of incident report data from Gas pipeline operators.

PHMSA proposes to revise this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM. The requested revision would revise form F7100.2-1, the "Natural and Other Gas Transmission and Gathering Pipeline Systems Annual Report" form, to collect the total number of leaks identified within a calendar year.

PHMSA currently estimates that 1,810 operators spend, on average, 47 hours completing form PHMSA F7100.2-1. PHMSA expects these operators to spend an additional 6 hours reporting the newly requested data on the total number of leaks identified and estimated emissions within the calendar year. This would increase the burden, per operator, from 47.5 hours annually to 53.5 hours annually to complete form PHMSA F7100.2-1. This revision would

result in an additional reporting burden of 10,860 hours annually bringing the overall burden for completing form F7100.2–1 to 96,835 hours (53.5 hours × 1,810 responses).

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,321.

Total Annual Burden Hours: 106,671 hours.

Frequency of Collection: Annual.

2. Title: Annual Report for Gas Distribution Operators.

OMB Control Number: 2137–0629.

Current Expiration Date: 05/31/2024.

Abstract: This information collection request would require operators of gas distribution pipeline systems to submit annual report data to the Office of Pipeline Safety in accordance with the regulations stipulated in 49 CFR part 191 by way of form PHMSA F 7100.1–1. The form is to be submitted once for each calendar year. The annual report form collects data about the pipe material, size, and age. The form also collects data on leaks from these systems as well as excavation damages. PHMSA uses the information to track the extent of gas distribution systems and normalize incident and leak rates. PHMSA proposes to revise this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM. The requested revision would revise form PHMSA F7100.1–1, the Gas Distribution Annual Report, to collect the total number of leaks identified within a calendar year, emissions from leaks by grade, and estimated emissions from other sources by source categories.

PHMSA estimates that, currently, 1,446 operators spend 17.5 hours completing the Gas Distribution Annual report each year. PHMSA expects these operators to spend an additional 6 hours reporting the newly requested data on the total number of leaks identified and estimated emissions within the calendar year. Because of this, PHMSA expects the burden for completing form PHMSA F7100.1–1 to increase to 23.5 (17.5+6) hours per report adding a total of 8,676 (6 hours × 1,446 operators) hours to the overall burden for this information collection.

Affected Public: Gas Distribution operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,446.

Total Annual Burden Hours: 33,981.

Frequency of Collection: Annual.

3. Title: Reporting Safety-Related Conditions on Gas, Hazardous Liquid,

and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities.

OMB Control Number: 2137–0578.

Current Expiration Date: 01/31/2023.

Abstract: 9 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazard to life, property, or the environment. PHMSA proposes to adjust the burden associated with this information collection in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM which exempts large-volume gas releases from safety-related condition reporting. The requested revision would reduce the burden for this information collection by 3 responses and 18 burden hours annually. PHMSA is not proposing to collect any additional data at this time.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 171.

Total Annual Burden Hours: 1,026.

Frequency of Collection: Annual.

4. Title: Incident and Annual Reports for Gas Pipeline Operators.

OMB Control Number: 2137–0635.

Current Expiration Date: 01/31/2023.

Abstract: Operators of natural gas pipelines and LNG facilities are required to report incidents, on occasion, to PHMSA per the requirements in 49 CFR part 191. This mandatory information collection covers the collection of incident report data from natural gas pipeline operators. The reports contained within this information collection support the Department of Transportation's strategic goal of safety. This information is an essential part of PHMSA's overall effort to minimize natural gas transmission, gathering, and distribution pipeline failures. PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM to include a new form, (PHMSA F 7100.5) designed to collect data on intentional and unintentional releases of gas with a volume of 1 MMCF or greater.

PHMSA estimates that it would receive 593 of these new reports on average each year (139 gas transmission, 254 gas gathering, and 200 gas distribution), with each report estimated to require 12 hours to prepare. This would result in an additional 593

responses and 7,116 burden hours for this information collection.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,592.

Total Annual Burden Hours: 11,572.

Frequency of Collection: On Occasion.

5. Title: National Pipeline Mapping System Program.

OMB Control Number: 2137–0596.

Expiration Date: 1/31/2023.

Type of Request: Revision of a previously approved information collection.

Abstract: The Pipeline Safety Improvement Act of 2002 (Pub. L. 107–355), 49 U.S.C. 60132, “National Pipeline Mapping System,” requires the operator of a pipeline facility (except distribution lines and gathering lines) to provide information to PHMSA. Each operator is required to submit geospatial data appropriate for use in the NPMS or data in a format that can be readily converted to geospatial data; the name and address of the person with primary operational control (to be known as its operator), and a means for a member of the public to contact the operator for additional information about the pipeline facilities it operates. Operators would submit the requested data elements once and make annual updates to the data if necessary. These data elements strengthen the effectiveness of PHMSA's risk rankings and evaluations, which are used as a factor in determining pipeline inspection priority and frequency; allow for more effective assistance to emergency responders by providing them with a more reliable, complete data set of pipelines and facilities; and provide better support to PHMSA's inspectors by providing more accurate pipeline locations and additional pipeline-related geospatial data that can be linked to tabular data in PHMSA's inspection database.

PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM to require gas gathering operators to be subject to NPMS reporting. PHMSA estimates that gas transmission operators currently spend approximately 120 hours each year submitting geospatial data through the NPMS. PHMSA estimates that, due to the changes in this NPRM, 378 Type A, B, and C operators would be added to the NPMS reporting community. This addition would increase the number of responses for this information collection by 378 and increase the overall reporting burden by 45,360 hours.

Respondents: Operators of gas transmission, hazardous liquid, or LNG pipeline facilities.

Annual Reporting and Recordkeeping Burden:

Estimated Number of Responses:

1,724 responses.

Estimated Total Annual Burden:

207,761 hours.

Frequency of Collection: Annually.

6. Title: Notification Requirements for Leak Detection and Repair.

OMB Control Number: PHMSA will request a new OMB Control No.

Current Expiration Date: TBD.

Abstract: A person owning or operating a natural gas pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request according to 49 U.S.C. 60117. The Pipeline Safety regulations contained within 49 CFR part 192 require operators to make various notifications upon the occurrence of certain events. The provisions covered under this ICR involve notification requirements for operators who utilize alternative or expanded technologies and methods when conducting leak detection and repair activities. These notification requirements are necessary to ensure safe operation of pipelines and ascertain compliance with gas pipeline safety regulations. These mandatory notifications help PHMSA to stay abreast of issues related to the health and safety of the nation's pipeline infrastructure.

PHMSA proposes to create this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM which requires operators to notify PHMSA in various instances pertaining to leak detection and repair activities. PHMSA expects all gas pipeline operators to be subject to these notification requirements. PHMSA estimates that it may receive 1,000 requests on average per year from gas distribution operators to extend the deadline for remedying leaks, with each of these requests requiring approximately 8 hours to prepare.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 1,000.

Total Annual Burden Hours: 8,000.

Frequency of Collection: On Occasion.

7. Title: Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137-0049.

Current Expiration Date: 3/31/2025.

Abstract: A person owning or operating a natural gas pipeline facility

is required to maintain records, make reports, and provide information to the Secretary of Transportation at the Secretary's request. This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Gas Pipeline Leak Detection and Repair NPRM which includes various recordkeeping requirements for operators pertaining to leak detection and remediation activities.

Affected Public: All gas pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 3,867,101 responses.

Total Annual Burden Hours:

1,904,157 hours.

Frequency of Collection: On Occasion.

Requests for copies of these information collections should be directed to Angela Hill at angela.hill@dot.gov. Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected; and

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503. Comments should be submitted on or prior to July 17, 2023.

J. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by state, local, and Tribal governments, in the aggregate of \$100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

PHMSA expects this NPRM would impose compliance costs of \$100 million or more (in 1996 dollars) on private sector entities. PHMSA has conducted an assessment (within the Preliminary RIA in the rulemaking docket) of the NPRM and has preliminarily concluded that the NPRM's proposed regulatory amendments will yield an appropriate balancing of costs and benefits.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), PHMSA solicits comments from the public to better inform its rulemaking process. PHMSA posts these comments, without edit, including any personal information the commenter provides, to www.regulations.gov, as described in the system of records notice (DOT/ALL-14 FDMS), which can be reviewed at www.dot.gov/privacy.

L. Executive Order 13609 and International Trade Analysis

E.O. 13609 ("Promoting International Regulatory Cooperation")³⁰⁸ requires agencies consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96-39), as amended by the Uruguay Round Agreements Act (Pub. L. 103-465), prohibits Federal

³⁰⁸ 77 FR 26413 (May 4, 2012).

agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards, so long as the standards have a legitimate domestic objective, such as providing for safety, and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards.

PHMSA engages with international standards setting bodies to protect the safety of the American public. PHMSA has assessed the effects of the NPRM and has preliminarily determined that its proposed regulatory amendments would not cause unnecessary obstacles to foreign trade.

M. Cybersecurity and Executive Order 14082

E.O. 14082 (“Improving the Nation’s Cybersecurity”) ³⁰⁹ expressed the Administration policy that “the prevention, detection, assessment, and remediation of cyber incidents is a top priority and essential to national and economic security.” E.O. 14082 directed the Federal Government to improve its efforts to identify, deter, and respond to “persistent and increasingly sophisticated malicious cyber campaigns.” In keeping with these policies and directives, PHMSA has assessed the effects of this NPRM to determine what impact the proposed regulatory amendments may have on cybersecurity risks for pipeline facilities.

PHMSA’s proposed requirements would not require pipeline operators to generate new security-sensitive records. Most of the pipeline facilities for which PHMSA proposes leak detection and repair requirements (and associated recordkeeping requirements) are already subject to such requirements—this NPRM simply proposes to enhance and expand those requirements. While computerized continuous or remote monitoring systems for pipeline facilities could be more vulnerable to cyber-attack than other technologies, the NPRM does not prescribe the use of any particular leak detection technology within operator advanced leak detection programs. PHMSA proposes to require operators to evaluate remote and real-time leak detection technologies as one potential approach when operators are designing the portfolio of technologies to be used to satisfy the proposed ALDP

requirements, but ultimately operators can choose to adopt or decline such technologies.

One proposal that may present relatively more cybersecurity risk is the proposed requirement for offshore gas gathering pipelines and Types A, B, and C gas gathering pipelines to provide geospatial data for NPMS. If hacked by a bad actor, this information could provide particularly sensitive information regarding the location of gas gathering infrastructure nationwide. However, the risk associated with hacking of NPMS data on gas gathering infrastructure appears relatively low compared to the risks associated with unauthorized release of NPMS data on gas transmission infrastructure. Data on gas transmission infrastructure has long been stored in NPMS and would likely be considered a more attractive target for bad actors given the greater importance of transmission lines in the U.S. interstate gas supply network.

Operators affected by these proposed requirements may also be subject to cybersecurity requirements and guidance under Transportation Security Administration (TSA) Security Directives,³¹⁰ as well as any new requirements resulting from ongoing TSA efforts to strengthen cybersecurity and resiliency in the pipeline sector, as discussed within an advance notice of proposed rulemaking published in November 2022.³¹¹ The Cybersecurity & Infrastructure Security Agency (CISA) and the Pipeline Cybersecurity Initiative (PCI) of the U.S. Department of Homeland Security also conduct ongoing activities to address cybersecurity risks to U.S. pipeline infrastructure and may introduce other cybersecurity requirements and guidance for gas pipeline operators.³¹²

PHMSA has considered the effects of the NPRM and has preliminarily determined that its proposed regulatory amendments would not materially affect the cybersecurity risk profile for pipeline facilities within the scope of the proposed amendments. PHMSA seeks comment on any other potential cybersecurity impacts of the proposed amendments beyond the considerations discussed here.

³¹⁰ E.g., TSA, “Ratification of Security Directive,” 86 FR 38209 (July 20, 2021) (ratifying TSA Security Directive Pipeline–2012–01, which requires certain pipeline owners and operators to conduct actions to enhance pipeline cybersecurity).

³¹¹ TSA, “Enhancing Surface Cyber Risk Management,” 87 FR 74702 (Nov. 30, 2022).

³¹² See, e.g., CISA, National Cyber Awareness System Alerts, <https://www.cisa.gov/uscert/ncas/alerts> (last accessed Feb. 1, 2023).

N. Severability

The purpose of this proposed rule is to operate holistically in addressing a panoply of issues related to safety and environmental hazards on regulated pipelines, with a focus on detection, grading, and repair of leaks. However, PHMSA recognizes that certain provisions focus on unique topics. Therefore, PHMSA preliminarily finds that the various provisions of this proposed rule are severable and able to function independently if severed from each other, and thus, in the event a court were to invalidate one or more of this proposed rule’s unique provisions, the remaining provisions should stand and continue in effect. PHMSA seeks comment on which portions of this proposed rule should or should not be severable.

List of Subjects

49 CFR Part 191

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 192

Natural gas, Pipeline safety, Safety.

49 CFR Part 193

Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 191, 192, and 193 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5121, 60101 *et seq.*, and 49 CFR 1.97.

■ 2. In § 191.3:

- a. Revise paragraph (1)(ii) in the definition of “Incident”; and
- b. Add the definition of “Large-volume gas release” in alphabetical order.

The revision and addition read as follows:

§ 191.3 Definitions.

* * * * *

Incident * * *

(1) * * *

(ii) Estimated property damage of \$122,000 or more, including loss to the operator and others, or both, but excluding each of the cost of gas lost, the cost to acquire permits, and the cost to remove and replace non-operator infrastructure that was not damaged by the release. For adjustments for inflation

³⁰⁹ 86 FR 26633 (May 17, 2021).

observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

Large-volume gas release means an intentional or unintentional release of 1 million cubic feet or more of gas from a gas pipeline facility as that term is defined in § 192.3.

■ 3. Add § 191.19 to read as follows:

§ 191.19 Large-volume gas release report.

Each operator of a gas pipeline facility must report a large-volume gas release on DOT Form PHMSA-F7100.5. Each report must be submitted within 30 days after detection of a large-volume gas release. A large-volume gas release report is not required if an incident report has already been submitted under this part for the same event and the release volume identified in the incident report is within 10 percent of the total release volume on cessation of the release.

■ 4. In § 191.23, revise paragraphs (a)(9) and (b)(2) to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) * * *

(9) Any safety-related condition that could lead to an imminent hazard to public safety and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG.

(b) * * *

(2) Is an incident or large-volume gas release, or results in an incident or large-volume gas release before the deadline for filing the safety-related condition report;

■ 5. In § 191.29, revise paragraph (a) introductory text, and remove paragraph (c) to read as follows:

§ 191.29 National Pipeline Mapping System.

(a) Each operator of a gas transmission pipeline, offshore gathering, Type A, Type B, or Type C regulated onshore gathering pipeline as determined in § 192.8 of this subchapter, or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 6. The authority citation for part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 et seq., and 49 CFR 1.97.

■ 7. In § 192.3, add the definitions of “Confined space,” “Gas-associated substructure,” “Leak or hazardous leak,” “Lower explosive limit (LEL),” “Substructure,” “Tunnel,” and “Wall-to-wall paved area” in alphabetical order to read as follows:

§ 192.3 Definitions.

Confined space means any subsurface structure, other than a building, of sufficient size to accommodate a person, and in which gas could accumulate or migrate. These include, vaults, certain tunnels, catch basins, and manholes.

Gas-associated substructure means a substructure that is part of an operator's pipeline but that is not itself designed to contain gas.

Leak or hazardous leak means, for the purposes of all subparts of part 192 except § 192.12(d) and subparts O and P, any release of gas from a pipeline that is uncontrolled at the time of discovery and is an existing, probable, or future hazard to persons, property, or the environment, or any uncontrolled release of gas from a pipeline that is or can be discovered using equipment, sight, sound, smell, or touch.

Lower explosive limit (LEL) means the minimum concentration of gas or vapor in air below which propagation of a flame does not occur in the presence of an ignition source at ambient pressure and temperature.

Substructure means any subsurface structure that is not large enough for a person to enter and in which gas could accumulate or migrate. Substructures include, but are not limited to, telephone and electrical ducts, and conduit, gas and water valve boxes, and meter boxes.

Tunnel is a subsurface passageway large enough for a person to enter and in which gas could accumulate or migrate.

Wall-to-wall paved area means an area where the ground surface between the curb of a paved street and the front

wall of a building is continuously paved, excluding intermittent landscaping, such as tree plots.

■ 8. In § 192.9:

- a. Revise paragraph (b);
- b. Redesignate paragraphs (d)(4) through (8) as paragraphs (d)(6) through (10);
- c. Add new paragraphs (d)(4) and (5);
- d. Remove the word “and” from the end of paragraph (d)(9);
- e. Revise newly redesignated paragraph (d)(10), and add paragraphs (d)(11) through (13);
- f. Redesignate paragraphs (e)(1)(iii) through (vii) as paragraphs (e)(1)(iv) through (viii);
- g. Add new paragraph (e)(1)(iii);
- h. Remove the word “and” at the end of paragraph (e)(1)(vii);
- i. Revise newly redesignated paragraph (e)(1)(viii);
- j. Add paragraphs (e)(1)(ix) through (xi); and
- k. Revise paragraph (f).

The revisions and additions read as follows:

§ 192.9 What requirements apply to gathering pipelines?

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, 192.714, 192.763(c)(1)(vi) and (c)(3), and in subpart O of this part.

(d) * * *

(4) Prepare, update, and follow a manual of written procedures for conducting operations, maintenance, and emergency response in accordance with § 192.605. Compliance with the requirements referenced in § 192.605(b)(1), (b)(2), (b)(12), and (e) is only required for pipeline facilities that are made subject to such requirements under this section or § 191.23;

(5) Develop and implement procedures for emergency plans in accordance with § 192.615;

(10) Conduct leakage surveys in accordance with § 192.706 within an advanced leak detection program in accordance with § 192.763;

(11) Investigate, grade, repair, and document leaks and leak repairs in accordance with §§ 192.703(c) through (d), 192.709, and 192.760;

(12) Conduct patrols in accordance with § 192.705; and

(13) Maintain and configure pressure relief devices to ensure proper device operation and minimize release of gas in accordance with § 192.773.

(e) * * *

(1) * * *

(iii) Prepare, update, and follow a manual of written procedures for conducting operations, maintenance, and emergency response in accordance with § 192.605. Compliance with the requirements referenced in § 192.605(b)(1), (2) and (12), (d), and (e) is only required for pipeline facilities that are made subject to such requirements under this section or § 191.23;

* * * * *

(viii) Conduct leakage surveys in accordance with §§ 192.706 within an advanced leak detection program in accordance with § 192.763;

(ix) Grade, investigate, repair, and document leaks and leak repairs in accordance with §§ 192.703(c) and (d), 192.709, and 192.760;

(x) Conduct patrols in accordance with § 192.705; and

(xi) Maintain and configure pressure relief devices to ensure proper device operation and minimize release of gas in accordance with § 192.773.

* * * * *

(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii), (vi), and (vii), and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:

* * * * *

■ 9. In § 192.12, revise paragraph (c) to read as follows:

§ 192.12 Underground natural gas storage facilities.

* * * * *

(c) *Procedural manuals.* Each operator of an UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Such manuals must include procedures for eliminating leaks and minimizing releases of gas. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations

or beginning an activity not yet implemented.

* * * * *

■ 10. In § 192.18, revise paragraph (c) to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to § 192.8, 192.9, 192.13, 192.179, 192.319, 192.461, 192.506(b), 192.607(e)(4), 192.607(e)(5), 192.619, 192.624(c)(2)(iii), 192.624(c)(6), 192.632(b)(3), 192.634, 192.636, 192.703(d)(4), 192.706(a)(2), 192.710(c)(7), 192.712(d)(3)(iv), 192.712(e)(2)(i)(E), 192.714, 192.745, 192.760(h), 192.763(c), 192.917, 192.921(a)(7), 192.927, 192.933, or 192.937(c)(7) a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (e.g., “other technology” or “alternative equivalent technology”) than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from PHMSA informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

* * * * *

■ 11. In § 192.167, revise paragraph (a)(2) to read as follows:

§ 192.167 Compressor stations: Emergency shutdown.

(a) * * *

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard to public safety;

* * * * *

■ 12. In § 192.169, revise paragraph (b) as follows:

§ 192.169 Compressor stations: Pressure limiting devices.

* * * * *

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard to public safety.

* * * * *

■ 13. In § 192.179, revise paragraph (c) to read as follows:

§ 192.179 Transmission line valves.

* * * * *

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard to public safety and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

* * * * *

■ 14. In § 192.199, revise the section heading and paragraph (e), and add paragraph (i) to read as follows:

§ 192.199 Requirements for design and configuration of pressure relief and limiting devices.

* * * * *

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard to public safety;

* * * * *

(i) All new, replaced, relocated, or otherwise changed pressure relief and limiting devices must be designed and configured, as demonstrated by a documented engineering analysis, to minimize unnecessary releases of gas by ensuring each of the following:

(1) The set and reset actuation pressure of the pressure relief device and where pressures are taken must minimize release volumes beyond what is necessary to provide adequate overpressure protection;

(2) The design (including sizing and material) and configuration of the pressure relief device and its associated piping must be appropriate for its set and reset actuation pressure to minimize pressure choking, compatible with the composition of transported gas, and suitable for reliable operation in expected operating and environmental conditions; and

(3) Installation of the pressure relief device must include upstream and downstream isolation valves to facilitate testing and maintenance.

■ 15. In § 192.361, revise paragraph (f)(3) to read as follows:

§ 192.361 Service lines: Installation.

* * * * *

(f) * * *

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard to public safety, and

extend above grade, terminating in a rain and insect resistant fitting.

* * * * *

■ 16. In § 192.363, revise paragraph (c) to read as follows:

§ 192.363 Service lines: Valve requirements.

* * * * *

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous to public safety, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

■ 17. In § 192.503 revise paragraph (a)(2) to read as follows:

§ 192.503 General requirements.

(a) * * *

(2) Each hazardous leak has been located and eliminated.

* * * * *

■ 18. In § 192.507, revise paragraph (a) to read as follows:

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

* * * * *

(a) The pipeline operator must use a test procedure that will ensure discovery of all hazardous leaks in the segment being tested.

* * * * *

■ 19. In § 192.509, revise paragraph (a) to read as follows:

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

* * * * *

(a) The test procedure used must ensure discovery of all hazardous leaks in the segment being tested.

* * * * *

■ 20. In § 192.513, revise paragraph (b) to read as follows:

§ 192.513 Test requirements for plastic pipelines.

* * * * *

(b) The test procedure must ensure discovery of all hazardous leaks in the segment being tested.

* * * * *

■ 21. In § 192.553, revise paragraph (a)(2) to read as follows:

§ 192.553 General requirements.

* * * * *

(a) * * *

(2) Each leak detected must be repaired before a further pressure increase is made.

* * * * *

■ 22. In § 192.557, revise paragraph (b)(2) to read as follows:

§ 192.557 Upgrading: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

* * * * *

(b) * * *

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found.

* * * * *

■ 23. In § 192.605, add paragraph (b)(13) to read as follows:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(b) * * *

(13) Eliminating leaks and minimizing releases of gas from pipelines, as well as remediating or replacing pipelines known to leak based on their material, design, or past operating and maintenance history.

* * * * *

■ 24. In § 192.617, add paragraph (e) to read as follows:

§ 192.617 Investigation of failures and incidents.

* * * * *

(e) *Failure defined.* For the purposes of this section, the term failure means when any portion of a pipeline becomes inoperable, is incapable of safely performing its intended function, or has become unreliable or unsafe for continued use.

■ 25. In § 192.629, revise paragraphs (a) and (b) to read as follows:

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be introduced into one end of the pipeline in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a mixture of gas and air hazardous to public safety, a slug of inert gas must be introduced into the pipeline before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be introduced into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a mixture of gas and air hazardous to public safety, a slug of inert gas must be released into the line before the air.

■ 26. In § 192.703, revise paragraph (c), and add paragraph (d) to read as follows:

§ 192.703 General.

* * * * *

(c) Leaks must be graded and repaired in accordance with the requirements in § 192.760.

(d) Compliance with §§ 192.703(c), 192.705 for patrols, 192.706 for leakage surveys, 192.760(a) through (h) for leak grading and repair, 192.763 for advanced leak detection programs, and 192.769 for qualification of leakage survey personnel, is not required for a compressor station on a gas transmission or gathering pipeline if:

(1) The facility is subject to methane emission monitoring and repair requirements under either:

(i) 40 CFR part 60, subparts OOOOa or OOOOb; or

(ii) an EPA-approved State plan or Federal plan which includes relevant standards at least as stringent as EPA's finalized emissions guidelines in 40 CFR part 60, subpart OOOOc;

(2) The facility is within the first block valve entering or exiting the compressor station covered by the emergency shutdown system as required in § 192.167 for station isolation from the pipeline; and

(3) Repair records are maintained for the life of the facility in accordance with § 192.760(i).

■ 27. In § 192.705, revise paragraph (b) to read as follows:

§ 192.705 Transmission lines: Patrolling.

* * * * *

(b) Operators must conduct patrols at least 12 times each calendar year at intervals not exceeding 45 days.

* * * * *

■ 28. Revise § 192.706 to read as follows:

§ 192.706 Transmission lines: Leakage surveys.

(a) *General.* Each operator must perform periodic leakage surveys in accordance with this section. Each leakage survey must be conducted according to the advanced leak detection program requirements in § 192.763, except that human or animal senses may be used in lieu of leak detection equipment only in the following circumstances:

(1) An offshore gas transmission pipeline below the waterline or offshore gathering pipeline below the waterline; or

(2) An onshore transmission line outside of an HCA or a gathering pipeline, each either in a Class 1 or Class 2 location, with advance notification to PHMSA in accordance with § 192.18. The notification must include tests or analyses demonstrating that the survey method would meet the ALDP performance standard in § 192.763(b) or (c) (as applicable).

(b) *Frequency of surveys.* Except as provided in paragraphs (c) and (d) of this section, leakage surveys must be performed at the following intervals:

(1) Pipelines outside of HCAs must be surveyed at least once per calendar year, but with an interval between surveys not to exceed 15 months; and

(2) Pipelines in HCAs must be surveyed as follows:

(i) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, with intervals not exceeding 7½ months;

(ii) In Class 4 locations, at least four times each calendar year, with intervals not exceeding 4½ months.

(c) *Non-odorized pipelines.* Leakage surveys for pipelines transporting gas in conformity with § 192.625 without an odor or odorant, must perform leakage surveys using leak detection equipment at the following intervals:

(1) In Class 3 locations, at least twice each calendar year, at intervals not exceeding 7½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4½ months.

(d) *Valves, flanges and certain other facilities.* Leakage surveys of all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher and ILI receiver facilities, and pipelines known to leak based on material (including, cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history, must be performed at the following intervals:

(1) In Class 1, Class 2, and Class 3 locations, at least twice each calendar year, at intervals not exceeding 7½ months.

(2) In Class 4 locations, at least four times each calendar year, at intervals not exceeding 4½ months.

■ 29. Revise § 192.723 to read as follows:

§ 192.723 Distribution systems: Leakage surveys.

(a) *General.* Each operator of a gas distribution pipeline must conduct periodic leakage surveys with leak detection equipment in accordance with this section. All leakage surveys performed pursuant to this section must use leak detection equipment that meets the requirements of § 192.763.

(b) *Business districts.* Leakage surveys must be conducted at least once each calendar year, at intervals not exceeding 15 months, consisting of atmospheric tests at each gas, electric, telephone, sewer, water, or other system manhole; crack in the pavement and sidewalks; and any other location that provides an opportunity for finding gas leaks.

(c) *Non-business districts.* Leakage surveys must be conducted at least once every 3 calendar years, at intervals not exceeding 39 months, unless a shorter inspection interval is required either by paragraph (d) of this section, the operator's operations and maintenance procedures, or the operator's integrity management plans under part 192, subpart P.

(d) *Frequency of regular leakage surveys.* Leakage surveys must be conducted at least once every calendar year, at intervals not exceeding 15 months, for:

(1) Cathodically unprotected distribution pipelines subject to § 192.465(e);

(2) Pipelines known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history; and

(3) Gas distribution pipeline systems protected by a distributed anode system, in the area of deficient readings identified during a cathodic protection survey pursuant to § 195.463 and appendix D, until the cathodic protection deficiency is remediated.

(e) *Investigating known leaks after environmental changes.* An operator must investigate a known leak, including conducting a leakage survey for possible gas migration, as soon as practicable when freezing ground, heavy rain, flooding, or other changes to the environment occur that could affect the venting of gas or could cause migration of gas to the outside wall of a building.

(f) *Extreme Weather Surveys.* Leakage surveys must be performed after extreme weather events and land movement with the likelihood to cause damage to the affected pipeline segment. The survey must be initiated within 72 hours after the cessation of the event, defined as either the point in time when the affected area can be safely accessed by the personnel and equipment required to perform the leakage survey or when the facility has been returned to service.

■ 30. In § 192.727, revise paragraphs (b) and (c) to read as follows:

§ 192.727 Abandonment or deactivation of facilities.

* * * * *

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard to public safety.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard to public safety.

* * * * *

■ 31. In § 192.751, revise paragraph (a) to read as follows:

§ 192.751 Prevention of accidental ignition.

* * * * *

(a) When an amount of gas potentially hazardous to public safety is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be present.

* * * * *

■ 32. Add § 192.760 to read as follows:

§ 192.760 Leak grading and repair.

(a) *General.* Each operator must have and follow written procedures for grading and repairing leaks that meet or exceed the requirements of this section.

(1) These requirements are applicable to leaks on all portions of a gas pipeline including, but not limited to, line pipe, valves, flanges, meters, regulators, tie-ins, launchers, and receivers.

(2) The leak grading and repair procedure must prioritize leaks by the hazard to public safety and the environment.

(3) Each leak must be investigated immediately and continuously until a leak grade determination has been made.

(b) *Grade 1 leaks.* (1) A grade 1 leak is any leak that constitutes an existing or probable hazard to persons or property or a grave hazard to the environment. A grade 1 leak includes a leak with any of following characteristics:

(i) Any leak that, in the judgment of operating personnel at the scene is regarded as an existing or probable hazard to public safety or a grave hazard to the environment;

(ii) Any amount of escaping gas has ignited;

(iii) Any indication that gas has migrated into a building, under a building, or into a tunnel;

(iv) Any reading of gas at the outside wall of a building, or areas where gas could migrate to an outside wall of a building;

(v) Any reading of 80% or greater of the LEL (60% for LPG systems) in a confined space;

(vi) Any reading of 80% or greater of the LEL (60% for LPG systems) in a substructure, (including gas associated substructures) from which any gas could migrate to the outside wall of a building;

(vii) Any leak that can be seen, heard, or felt; or

(viii) Any leak defined as an incident in § 191.3.

(2) An operator must promptly repair a grade 1 leak and eliminate the hazardous conditions by taking immediate and continuous action by operator personnel at the scene.

Immediate action means the operator will begin instant efforts to remediate and repair the leak upon detection and to eliminate any hazardous conditions caused by the leak. Continuous means that the operator must maintain on-site remediation efforts until the leak repair has been completed. This may require one or more of, but not limited to, the following actions be taken without delay:

(i) Implementing an emergency plan pursuant to § 192.615;

(ii) Evacuating premises;

(iii) Blocking off an area;

(iv) Rerouting traffic;

(v) Eliminating sources of ignition;

(vi) Venting the area by removing manhole covers, bar holing, installing vent holes, or other means;

(vii) Stopping the flow of gas by closing valves or other means; or

(viii) Notifying emergency responders.

(c) *Grade 2 leaks.* (1) A grade 2 leak constitutes a probable future hazard to persons or property or a significant hazard to the environment, and includes any leak (other than a grade 1 leak) with any the following characteristics:

(i) A reading of 40% or greater of the LEL under a sidewalk in a wall-to-wall paved area that does not qualify as a grade 1 leak;

(ii) A reading at or above 100% of LEL under a street in a wall-to-wall paved area that has gas migration and does not qualify as a grade 1 leak;

(iii) A reading between 20% and 80% of the LEL in a confined space;

(iv) A reading less than 80% of the LEL in a substructure (other than gas associated substructures) from which gas could migrate;

(v) A reading of 80% or greater of the LEL in a gas associated substructure from which gas could not migrate;

(vi) Any reading of gas that does not qualify as a grade 1 leak that occurs on a transmission pipeline or a Type A or Type C regulated gas gathering line;

(vii) Any leak with a leakage rate of 10 cubic feet per hour (CFH) or more that does not qualify as a grade 1 leak;

(viii) Any leak of LPG or hydrogen gas that does not qualify as a grade 1 leak; or

(ix) Any leak that, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair within six months or less.

(2) An operator must schedule repair based on the severity or likelihood of hazard to persons, property, or the environment. A grade 2 leak must be repaired within six months of detection, unless a shorter repair deadline is required by the operator's procedures, integrity management program, or paragraphs (c)(3) through (6) of this section. The operator must re-evaluate each grade 2 leak at least once every 30 days until it is repaired.

(3) The operator must complete repair of any grade 2 leak on a gas transmission or Type A gathering pipeline, each located in an HCA, Class 3 or Class 4 location, within 30 days of detection. If repair cannot be completed within 30 days due to permitting requirements or parts availability, the operator must take continuous action to monitor and repair the leak.

(4) Each operator's operations and maintenance procedure must include a methodology for prioritizing the repair of grade 2 leaks, including criteria for leaks that warrant repair within 30 days of detection pursuant to § 192.760(c). Grade 2 leaks with a repair deadline of less than 30 days must be re-evaluated at least once every 2 weeks until the repair is complete. This methodology must include an analysis of, at a minimum, each of the following parameters:

(i) The volume and migration of gas emissions;

(ii) The proximity of gas to buildings and subsurface structures;

(iii) The extent of pavement; and

(iv) Soil type and conditions, such as frost cap, moisture, and natural venting.

(5) Each operator must take immediate and continuous action to complete repair of a grade 2 leak and eliminate the hazard when freezing ground, heavy rain, flooding, new pavement, or other changes to the environment are anticipated or occur near an existing grade 2 leak that may affect the venting or migration of gas and could allow gas to migrate to the outside wall of a building.

(6) An operator must complete repair of known grade 2 leaks existing on or before [effective date of the final rule] before [date 1 year after the publication date of the final rule].

(d) *Grade 3 leaks.* (1) A grade 3 leak is any leak that does not meet the criteria of a grade 1 or grade 2 leak. In order to qualify as a grade 3 leak, none of the criteria for grade 1 or 2 leaks must be present. Grade 3 leaks may include,

but are not limited to, leaks with the following characteristics:

(i) A reading of less than 80% of the LEL in gas associated substructures from which gas is unlikely to migrate; or

(ii) Any reading of gas under pavement outside of a wall-to-wall paved area where gas is unlikely to migrate to the outside wall of a building; or

(iii) A reading of less than 20% of the LEL in a confined space.

(2) A grade 3 leak must be repaired within 24 months of detection, except as described below:

(i) A grade 3 leak known to exist on or before [effective date of the final rule] must be repaired prior to [date 3 years after the publication date of the final rule].

(ii) A grade 3 leak may be evaluated in accordance with paragraph (d)(3) of this section and repairs postponed if the segment containing the leak is scheduled for replacement, and is replaced, within five years of detection of the leak.

(3) Each operator must re-evaluate each grade 3 leak at least once every six months until repair of the leak is complete.

(e) *Post-repair inspection.* (1) A leak repair is considered to be complete when an operator obtains a gas concentration reading of 0% gas at the leak location after a permanent repair.

(2) An operator must conduct a post-repair leak inspection at least 14 days after but no later than 30 days after the date of the repair to determine if the repair was complete.

(3) If a post-repair inspection shows a gas concentration reading greater than 0% gas, the repair is not complete, and operator must take the following actions:

(i) If the post repair inspection finds gas concentrations or migration indicating that the potential for a grade 1 or grade 2 condition leak exists, the operator must re-inspect the repair and take immediate and continuous action to eliminate the hazard and complete repair;

(ii) If the operator's post repair inspection does not find a gas concentration reading of 0% at the leak location, and a grade 1 or grade 2 condition does not exist, then the operator must remediate the repair and re-inspect the leak within 30 days and continue reevaluating the leak at least once every 30 days until there is a gas concentration reading of 0%. Leak repair must be complete within the repair deadline for a grade 3 leak under § 192.760(d)(2), or for a downgraded leak, the repair deadline under § 192.760(g).

(4) A post repair inspection is not required for any leak that is eliminated by routine maintenance work—such as adjustment or lubrication of above-ground valves, or tightening of packing nuts on valves with seal leaks—and is a grade 3 leak or occurs on an aboveground pipeline facility.

(f) *Upgrading leak grades.* If at any time an operator receives information that a higher-priority grade condition exists in connection with a previously-graded leak, the operator must upgrade that leak to the higher-priority grade. When an operator upgrades a leak to a higher-priority grade, the time period to complete the repair is the earlier of either the remaining time based on its original leak grade or the time allowed for repair under its new leak grade measured from the time the operator received the information that a higher-priority grade condition exists.

(g) *Downgrading leak grades.* A leak may not be downgraded to a lower-priority leak grade unless a temporary repair to the pipeline has been made or a permanent repair was attempted but gas was detected during the post-repair inspection under paragraph (e) of this section. In this case, the time period for repair is the remaining time allowed for repair under its new grade measured from the time the leak was detected.

(h) *Extension of leak repair.* An operator may request an extension of the leak repair deadline requirements for an individual grade 3 leak with advance notification to and no objection from PHMSA pursuant to § 192.18. The operator's notification must show that the delayed repair timeline would not result in an increased risk to public safety, as well as that either the required repair deadline is impracticable, or that remediation within the specified time frame would result in the release of more gas to the environment than would occur with continued monitoring. The notification must include the following:

(1) A description of the leaking facility including the location, material properties, the type of equipment that is leaking, and the operating pressure;

(2) A description of the leak and the leak environment, including gas concentration readings, leak rate if known, class location, nearby buildings, weather conditions, soil conditions, and other conditions that could affect gas migration, such as pavement;

(3) A description of the alternative repair schedule and a justification for the same; and

(4) Proposed emissions mitigation methods, monitoring, and repair schedule.

(i) *Recordkeeping.* (1) Records of the complete history of the investigation

and grading of each leak must be retained for 5 years after the final post-repair inspection is completed under paragraph (e) of this section. These records include all records documenting leak grading, monitoring, inspections, upgrades, and downgrades.

(2) Records of the detection, remediation, and repair of the leak must be retained for the life of the pipeline. This must include the date, location, and description of each leak detected, and repair or remediation of the same, made on the pipeline.

■ 33. Add § 192.763 to read as follows:

§ 192.763 Advanced Leak Detection Program.

(a) *Advanced Leak Detection Program (ALDP) elements.* Each operator must have and follow a written ALDP that includes the following elements:

(1) *Leak detection equipment.* (i) The ALDP must include a list of leak detection equipment used in operator leakage surveys, pinpointing leak locations, and investigating leaks.

(ii) Leak detection equipment used for leakage surveys, pinpointing leak locations, investigating, and inspecting leaks must have a minimum sensitivity of 5 parts per million for each gas being surveyed. The operator must validate the sensitivity of this equipment before using the device in a leakage survey by testing with a known concentration of gas.

(iii) Leak detection equipment must be selected based on a documented analysis considering, at a minimum, the state of commercially available leak detection technologies and practices, the size and configuration of the pipeline system, and system operating parameters and environment. At a minimum, operators must analyze the effectiveness of the following technologies for their systems:

(A) The use of handheld leak detection equipment capable of detecting and locating all leaks of 5 parts per million or more when measured within 5 feet of the pipeline or within a wall-to-wall paved area, in conjunction with locating equipment to verify the tools are sampling the area within 5 feet of the buried pipeline. The procedure must include sampling the atmosphere near cracks, vaults, or any other surface feature where gas could migrate;

(B) Periodic surveys performed with leak detection equipment mounted on mobile, aerial, or satellite-based platforms that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more when measured within 5 feet of the

pipeline, or within a wall-to-wall paved area;

(C) Periodic surveys performed with optical, infrared, or laser-based leak detection equipment that can sample or inspect the area within 5 feet of the pipeline, or within a wall-to-wall paved area, capable of detecting and pinpointing all leaks of 5 parts per million or more;

(D) Continuous monitoring for leaks via stationary sensors, pressure monitoring, or other means that provide alarms or alerts and that, in conjunction with confirmation by hand-held equipment, is capable of detecting and pinpointing all leaks of 5 parts per million or more when measured within 5 feet of the pipeline, or within a wall-to-wall paved area; and

(E) Systematic use of other commercially available technology capable of detecting and pinpointing all leaks producing a reading of 5 parts per million or more within 5 feet of the pipeline, or within a wall-to-wall paved area.

(2) *Leak detection practices.* At a minimum, an operator must have and follow written procedures for:

(i) *Performing leakage surveys.* Operators must have procedures for performing leakage surveys required for §§ 192.706 and 192.723 using each selected leak detection technology as described in paragraph § 192.763(a)(1). The procedures must define environmental and operational conditions for which each leak detection technology is and is not permissible. The operator's procedures must follow the leak detection equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters.

(ii) *Pinpointing and investigating leaks.* The location of the source of each leak indication on an onshore pipeline or any portion of an offshore pipeline above the waterline must be pinpointed and investigated with handheld leak detection equipment. Leak indications on offshore pipelines below the waterline may be pinpointed with human senses.

(iii) *Validating performance.* Operators must have procedures validating that leak detection equipment meets the requirement of paragraph (a)(1)(ii) of this section. The operator must have procedures for validating the sensitivity of the equipment before initial use by testing with a known concentration of gas and at the required offset conditions of 5 feet. Records validating equipment performance must be maintained for five years after the

date the device is no longer used by the operator.

(iv) *Maintaining and calibrating leak detection equipment.* At a minimum, procedures must follow the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction. Records validating equipment calibration and failures indicating recalibration is necessary must be maintained for 5 years after the date the individual device is retired by the operator.

(3) *Leakage survey frequency.* Leakage survey frequency must be sufficient to detect all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall-to-wall paved area, but may be no less frequent than required in §§ 192.706 and 192.723. Less sensitive equipment, challenging survey conditions, or facilities known to leak based on their material, design, or past operating and maintenance history may require more frequent surveys to detect leaks consistent with paragraph (b) of this section.

(4) *Periodic evaluation and improvement.* The ALDP must include procedures and records showing the operator is meeting all of the program requirements.

(i) The operator must evaluate the ALDP at least once each calendar year but with a maximum interval not to exceed 15 months.

(ii) The operator must make changes to any program elements necessary to locate and eliminate leaks and minimize releases of gas.

(iii) When considering changes to program elements, operators must analyze, at a minimum, the performance of the leak detection equipment used, the adequacy of the leakage survey procedures, advances in leak detection technologies and practices, the number of leaks that are initially detected by the public, the number of leaks and incidents, and estimated emissions from leaks detected pursuant to this section.

(iv) The operator must document any improvements needed to the program.

(b) *Advanced leak detection performance standard.* Each operator's ALDP described in paragraph (a) of this section must be capable of detecting all leaks that have a sufficient release rate to produce a reading of 5 parts per million or more of gas when measured from a distance of 5 feet or less from the pipeline, or within a wall-to-wall paved area.

(1) The performance of the ALDP must be validated and documented with engineering tests and analyses.

(2) Records validating that the ALDP meets the performance standard must be maintained for at least 5 years after the date that ALDP is no longer used by the operator.

(c) *Alternative advanced leak detection performance standard.* For gas pipelines other than natural gas pipelines, and for natural gas transmission, offshore gathering, and Types A, B, and C gathering pipelines located in Class 1 or Class 2 locations, an operator may use an alternative ALDP performance standard (and supporting leak detection equipment) with prior notification to, and with no objection from, PHMSA in accordance with § 192.18. PHMSA will only approve a notification if operator, in the notification, demonstrates that the alternative performance standard is consistent with pipeline safety and equivalent to the standard in paragraph (b) of this section for reducing greenhouse gas emissions and other environmental hazards. The notification must include:

(1) Mileage by system type;

(2) Known material properties, location, HCAs, operating parameters, environmental conditions, leak history, and design specifications, including coating, cathodic protection status, and pipe welding or joining method;

(3) The proposed performance standard;

(4) Any safety conditions, such as increased survey frequency;

(5) The leak detection equipment, procedures, and leakage survey frequencies the operator proposes to employ;

(6) Data on the sensitivity and the leak detection performance of the proposed alternative ALDP standard; and

(7) The gas transported by the pipeline.

■ 34. Add § 192.769 to read as follows:

§ 192.769 Qualification of leakage survey, investigation, grading, and repair personnel.

Only individuals qualified under subpart N of this part may conduct leakage survey, investigation, grading, and repair. Individuals qualified under subpart N must also possess training, experience, and knowledge in the field of leakage survey, leak investigation, and leak grading, including documented work history or training associated with those activities.

■ 35. Add § 192.770 to read as follows:

§ 192.770 Minimizing emissions from gas transmission pipeline blowdowns.

(a) Except as provided in paragraph (b) of this section, when an operator performs any intentional release of gas (including blowdowns or venting for scheduled repairs, construction, operations, or maintenance) from a gas transmission pipeline, the operator must prevent or minimize the release of gas to the environment through one or more of the following methods:

(1) Isolating the smallest section of the pipeline necessary to complete the task by use of valves or the installation of control fittings;

(2) Routing gas released from the pipeline from the nearest isolation valves or control fittings to a flare or to other equipment as fuel gas;

(3) Reducing pressure by use of in-line compression;

(4) Reducing pressure by use of mobile compression to a segment or storage vessel adjacent to the nearest isolation valves;

(5) Transferring the gas to a segment of a lower pressure pipeline system adjacent to the nearest isolation valves; or

(6) Employing an alternative method demonstrated to result in a release volume reduction of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an event that activates its emergency plan under § 192.615(a)(3) when such minimization would delay emergency response or result in a safety risk during pipeline assessments or maintenance. Each emergency release conducted without mitigation must be documented, including the justification for release without mitigation.

(c) Operators must document the methodologies used in paragraph (a) of this section and describe how the methodologies minimize the release of gas to the environment.

■ 36. Add § 192.773 to read as follows:

§ 192.773 Pressure relief device maintenance and adjustment of configuration.

(a) Each operator must develop, maintain, and follow written operations and maintenance procedures to assess the proper function of pressure limiting or relief device and to repair or replace each failed pressure limiting or relief device. When a pressure limiting or relief device fails to operate or allows gas to release to the atmosphere at an operating pressure above or below the set actuation pressure range defined for the device in the operator's operations

and maintenance procedure, the operator must:

(1) Assess the pilot, springs, seats, pressure gauges, and other components to ensure proper functioning, sensing, and set/reset actuation pressures are within actuation pressure tolerances;

(2) Assess the inlet and outlet piping for piping that restricts the inlet or outlet gas flow, piping that restricts the sensing pressure, debris, and other restrictions that could impede the operation or restrict the capacity to relieve overpressure conditions;

(3) Repair or replace the device to eliminate the malfunction as follows:

(i) If a pressure relief device activates above its set pressure and above the pressure limits in § 192.201(a) or 192.739 as applicable, fails to operate, or otherwise fails to provide overpressure protection, the operator must repair or replace the device or pressure sensing equipment immediately.

(ii) If a pressure relief device allows gas to release to the atmosphere at an operating pressure below the set actuation pressure range, the operator must take immediate and continuous action with on-site personnel to stop the release until the device is repaired or replaced. The relief device or pressure sensing equipment must be repaired or replaced as soon as practicable but within 30 days.

(b) Each operator must develop, maintain, and follow written operations and maintenance procedures to ensure that a pressure relief device configuration, as demonstrated by a documented engineering analysis, employs set and reset actuation pressures ensuring minimization of release volumes while providing adequate overpressure protection.

(c) Records under this section must be maintained as follows:

(1) Records of relief devices malfunctions must be maintained for 5 years after repair or replacement.

(2) Records pertaining to repair, replacement, or reconfiguration (including any engineering analyses) of a pressure relief device must be maintained for the life of the pipeline.

■ 37. In § 192.1007, revise paragraphs (e)(1)(i) and (v) as follows:

§ 192.1007 What are the required elements of an integrity management plan?

* * * * *

(e) * * *

(1) * * *

(i) Number of hazardous leaks either eliminated or repaired (or total number

of leaks if all leaks are repaired when found), categorized by cause;

* * * * *

(v) Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by material; and

* * * * *

PART 193—LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

■ 38. The authority citation for part 193 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60103, 60104, 60108, 60109, 60110, 60113, 60118; and 49 CFR 1.53.

■ 39. In § 193.2503, add paragraph (h) to read as follows:

§ 193.2503 Operating procedures.

* * * * *

(h) Eliminating leaks and minimizing releases of gas.

■ 40. Add § 193.2523 to read as follows:

§ 193.2523 Minimizing emissions from blowdowns and boiloff.

(a) Except as provided in paragraph (b) of this section, an operator of an LNG facility must minimize intentional emissions of natural gas from LNG facilities, including tank boiloff or blowdowns for repairs, construction, operations, or maintenance. The operator must minimize the release of natural gas to the environment by use of one or more of the following methods:

(1) Isolating a smaller section of the piping segments by use of valves or the installation of control fittings;

(2) Routing gas released from the facility to a flare, or to other equipment for use as fuel gas;

(3) Transferring gas or LNG to a storage tank or local pressure vessel; or

(4) Employing an alternative method demonstrated to result in release volume reductions of at least 50% compared to venting gas directly to the atmosphere without mitigative action.

(b) An operator is not required to comply with the provisions of paragraph (a) of this section during an emergency resulting in the activation of their emergency procedures under § 193.2509. An operator must document each emergency release without mitigation described in paragraph (b) of this section, including the justification for release without mitigation.

(c) The operator must document the method or methods used and describe how those methods minimize the release of natural gas to the environment.

■ 41. In § 193.2605, add paragraph (b)(3) to read as follows:

§ 193.2605 Maintenance procedures.

* * * * *

(b) * * *

(3) Procedures for eliminating leaks and minimizing releases of gas.

* * * * *

■ 42. Add § 193.2624 to read as follows:

§ 193.2624 Leakage surveys.

(a) Each operator of an LNG facility, including mobile, temporary, and satellite facilities must conduct periodic methane leakage surveys, on equipment and components within their facilities containing methane or LNG, at least four times each calendar year, with a maximum interval between surveys not exceeding 4½ months, using leak detection equipment. Leak detection equipment must be capable of detecting and locating all methane leaks producing a reading of 5 parts per million or more of within 5 feet of the component or equipment surveyed.

(b) Operators must have written procedures providing for each of the following:

(1) Validating the leakage survey equipment and performing leakage surveys consistent with the equipment manufacturer's instructions for survey methods and allowable environmental and operational parameters;

(2) Validating the sensitivity of this equipment by the operator before initial use by testing with a known concentration of gas at a required offset condition of 5 feet; and

(3) Calibrating the equipment consistent with the equipment manufacturer's instructions for calibration and maintenance. Leak detection equipment must be recalibrated or replaced following any indication of malfunction.

(c) Each operator must maintain records of the leak survey and equipment sensitivity validation and calibration for five years after the leakage survey.

(d) Operators must review the results of the methane leakage surveys and address any methane leaks and abnormal operating conditions in accordance with their written maintenance procedures or abnormal operating procedures.

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Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

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Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 257

[EPA-HQ-OLEM-2020-0107; FRL-7814-02-OLEM]

RIN 2050-AH14

Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On April 17, 2015, the Environmental Protection Agency (EPA or the Agency) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. On August 21, 2018, the United States Court of Appeals for the District of Columbia Circuit vacated the exemption for inactive surface impoundments at inactive facilities and remanded the issue back to EPA to take further action consistent with the opinion in *Utility Solid Waste Activities Group, et al. v. EPA*. The Agency is proposing to establish regulatory requirements for inactive surface impoundments at inactive facilities (legacy CCR surface impoundments). EPA is also proposing to establish groundwater monitoring, corrective action, closure, and post-closure care requirements for all CCR management units (regardless of how or when that CCR was placed) at regulated CCR facilities. EPA is also proposing several technical corrections to the existing regulations, such as correcting certain citations and harmonizing definitions.

DATES:

Comments due: Comments must be received on or before July 17, 2023.

Public Hearing: EPA will hold an in-person public hearing on June 28, 2023 and a virtual public hearing on July 12, 2023. Please refer to the **SUPPLEMENTARY INFORMATION** section for additional information on the public hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA-HQ-OLEM-2020-0107, by any of the following methods:

- *Federal eRulemaking Portal:* <https://www.regulations.gov/> (our preferred method). Follow the online instructions for submitting comments.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Office of Land and Emergency

Management (OLEM) Docket, Mail Code 28221T, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

• *Hand Delivery or Courier (by scheduled appointment only):* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations 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 detailed instructions on sending comments and additional information on the rulemaking process, see the “Public Participation” heading of the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For questions concerning this proposal, contact Michelle Lloyd, Office of Resource Conservation and Recovery, Materials Recovery and Waste Management Division, Environmental Protection Agency, 1200 Pennsylvania Avenue NW, MC: 5304T, Washington, DC 20460; telephone number: (202) 566–0560; email address: Lloyd.Michelle@epa.gov. For more information on this rulemaking please visit <https://www.epa.gov/coalash>.

SUPPLEMENTARY INFORMATION:

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List of Acronyms

ACM Assessment of Corrective Measures
ANPRM Advance Notice of Proposed Rulemaking

ASD alternative source demonstration
CAA Clean Air Act
CBI Confidential Business Information
CCR coal combustion residuals
CCRMU coal combustion residuals management unit
CERCLA Comprehensive Environmental Response, Compensation, and Liability Act
CFR Code of Federal Regulations
CWA Clean Water Act
EAP Emergency Action Plan
EJ environmental justice
ELG Effluent Limitation Guidelines
EPA Environmental Protection Agency
EPRI Electric Power Research Institute
FR Federal Register
GWMCA groundwater monitoring and corrective action
GWPS groundwater protection standard
HQ hazard quotient
HSWA Hazardous and Solid Waste Amendments
ICR Information Collection Request
LEAF Leaching Environmental Assessment Framework
MCL maximum contaminant level
NAICS North American Industry Classification System
NPDES National Pollution Discharge Elimination System
NPL National Priorities List
NTTAA National Technology Transfer and Advancement Act
OMB Office of Management and Budget
OSHA Occupational Safety and Health Administration
PM particulate matter
PRA Paperwork Reduction Act
PUC Public Utility Commission
QA/QC quality assurance/quality control
RCRA Resource Conservation and Recovery Act
RIA Regulatory Impact Analysis
SSI statistically significant increase
SSL statistically significant level
TDS total dissolved solids
TSCA Toxic Substances Control Act
TSDF Transportation Storage and Disposal Facility
USGS U.S. Geological Survey
USWAG Utility Solid Waste Activities Group
WIIN Water Infrastructure Improvements for the Nation

I. Public Participation

A. Written Comments

Submit your comments, identified by Docket ID No. EPA-HQ-OLEM-2020-0107, at <https://www.regulations.gov> (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. EPA may publish any comment received to its public docket. Do not submit to EPA's docket at <https://www.regulations.gov> 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, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit <https://www.epa.gov/dockets/commenting-epa-dockets>.

B. Participation in In-Person Public Hearing

EPA will begin pre-registering speakers for the hearing upon publication of this document in the **Federal Register**. To register to speak at the hearing, please use the online registration form available on EPA's CCR website (<https://www.epa.gov/coalash>) or contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to register to speak at the hearing. The last day to pre-register to speak at the hearing will be June 26, 2023. On June 27, 2023, EPA will post a general agenda for the hearing on EPA's CCR website (<https://www.epa.gov/coalash>).

EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule. Additionally, requests to speak will be taken the day of the hearing at the hearing registration desk. EPA will make every effort to accommodate all speakers who arrive and register, although preferences on speaking times may not be able to be fulfilled.

Each commenter will have five (5) minutes to provide oral testimony. EPA encourages commenters to provide EPA with a copy of their oral testimony electronically by emailing it to the person listed in the **FOR FURTHER INFORMATION CONTACT** section. EPA also recommends submitting the text of your oral comments as written comments to the rulemaking docket. If EPA is anticipating a high attendance, the time allotment per testimony may be shortened to no shorter than three (3) minutes per person to accommodate all those wishing to provide testimony and who have pre-registered. While EPA will make every effort to accommodate all speakers who do not preregister, opportunities to speak may be limited based upon the number of pre-registered speakers. Therefore, EPA strongly encourages anyone wishing to speak to preregister. Participation in the public

hearing does not preclude any entity or individual from submitting a written comment.

EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing are posted online at EPA's CCR website at <https://www.epa.gov/coalash>. While EPA expects the hearing to go forward as set forth above, please monitor our website or contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to determine if there are any updates. EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of an interpreter or special accommodations such as audio transcription, please pre-register for the hearing with the person listed in the **FOR FURTHER INFORMATION CONTACT** section and describe your needs by June 14, 2023. EPA may not be able to arrange accommodations without advance notice.

C. Participation in Virtual Public Hearing

EPA will begin pre-registering speakers for the hearing upon publication of this document in the **Federal Register**. To register to speak at the hearing, please use the online registration form available on EPA's CCR website (<https://www.epa.gov/coalash>) or contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to register to speak at the virtual hearing. The last day to pre-register to speak at the hearing will be July 10, 2023. On July 11, 2023, EPA will post a general agenda for the hearing on EPA's CCR website at: <https://www.epa.gov/coalash>.

EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule. Additionally, requests to speak will be taken the day of the hearing according to the procedures specified on EPA's CCR website (<https://www.epa.gov/coalash>) for this hearing. The Agency will make every effort to accommodate all speakers who arrive and register, although preferences on speaking times may not be able to be fulfilled.

Each commenter will have five (5) minutes to provide oral testimony. EPA encourages commenters to provide the

EPA with a copy of their oral testimony electronically (via email) by emailing it to person listed in the **FOR FURTHER INFORMATION CONTACT** section. If EPA is anticipating a high attendance, the time allotment per testimony may be shortened to no shorter than three (3) minutes per person to accommodate all those who wish to provide testimony and have pre-registered. While EPA will make every effort to accommodate all speakers who do not preregister, opportunities to speak may be limited based upon the number of preregistered speakers. Therefore, EPA strongly encourages anyone wishing to speak to preregister. Participation in the virtual public hearing does not preclude any entity or individual from submitting a written comment.

EPA may ask clarifying questions during the oral presentations but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing. Verbatim transcripts of the hearings and written statements will be included in the docket for the rulemaking.

Please note that any updates made to any aspect of the hearing is posted online on EPA's CCR website at <https://www.epa.gov/coalash>. While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to determine if there are any updates. EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the service of a translator, please pre-register for the hearing and describe your needs by June 28, 2023. If you require special accommodations such as audio transcription or closed captioning, please pre-register for the hearing and describe your needs by June 28, 2023. We may not be able to arrange accommodations without advance notice. Registrants should notify the person listed in the **FOR FURTHER INFORMATION CONTACT** section and indicate on the registration form any such needs when they pre-register to speak.

II. General Information

A. Does this action apply to me?

This rule applies to and may affect all CCR generated by electric utilities and independent power producers that fall within the North American Industry Classification System (NAICS) code

221112. The reference to NAICS code 221112 is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This discussion lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not described here could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in 40 CFR 257.50 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the Agency taking?

EPA is proposing to amend the regulations governing the disposal of CCR in landfills and surface impoundments, codified in subpart D of part 257 of Title 40 of the Code of Federal Regulations (CFR) (CCR regulations). Specifically, the Agency is proposing to establish regulatory requirements for inactive CCR surface impoundments at inactive utilities (“legacy CCR surface impoundment” or “legacy impoundment”). This action is being proposed in response to the August 21, 2018, opinion by the U.S. Court of Appeals for the District of Columbia Circuit in *Utility Solid Waste Activities Group v. EPA*, 901 F.3d 414 (D.C. 2018) (“USWAG decision” or “USWAG”) that vacated and remanded the provision exempting legacy impoundments from the CCR regulations. This action includes adding a definition for legacy CCR surface impoundments and other terms relevant to this rulemaking. It also proposes to require that legacy CCR surface impoundments comply with certain existing CCR regulations with tailored compliance deadlines.

While this action is responsive to the D.C. Circuit’s order, it is also driven by the record, which clearly demonstrates that regulating legacy CCR surface impoundments will have significant quantified and unquantified public health and environmental benefits. As EPA concluded in 2015, the risks posed by unlined CCR surface impoundments are substantial, and the risks from legacy impoundments are at least as significant. EPA’s 2014 Risk Assessment concluded that the cancer risks from unlined surface impoundments ranged from 3×10^{-4} for trivalent arsenic to 4×10^{-5} for pentavalent arsenic. Non-cancer risks from these same units also significantly exceeded EPA’s level of concern, with estimated Hazard

Quotients (HQ) of two for thallium, three for lithium, four for molybdenum and eight for trivalent arsenic. In addition, as described in Unit IV.B.1 of this preamble, information obtained since 2015 indicates that the risks for legacy CCR surface impoundments are likely to be greater than EPA originally estimated. Finally, based on the demographic composition and environmental conditions of communities within one and three miles of legacy CCR surface impoundments, these proposals will reduce existing disproportionate and adverse effects on economically vulnerable communities, as well as those that currently face environmental burdens. For example, in Illinois the population living within 1 mile of legacy CCR surface impoundment sites is over three times as likely compared to the state average to have less than a high school education (35.66% compared to 10.10%, see RIA exhibit ES.14), and that population already experiences higher than average exposures to particulate matter, ozone, diesel emissions, lifetime air toxics cancer risks, and proximity to traffic, Superfund sites, Risk Management Plan sites, and hazardous waste facilities (see RIA exhibit ES.15). Following on the significant progress EPA has made over many decades to reduce dangerous pollution from coal-fired electric utilities’ stack emissions and effluents, this proposed rule will help EPA further ensure that the communities and ecosystems closest to coal facilities are sufficiently protected from harm from groundwater contamination, surface water contamination, fugitive dust, floods and impoundment overflows, and threats to wildlife.

EPA is also proposing to establish requirements to address the risks from currently exempt solid waste management that involves the direct placement of CCR on the land.¹ EPA is proposing to extend a subset of the existing requirements in part 257, subpart D to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR Rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. In this proposal, EPA refers to these as CCR management units, or CCRMU. This proposal would apply to all existing CCR facilities and all inactive facilities with legacy CCR

¹ Regulated CCR units consist of new and existing landfills and surface impoundments, including any lateral expansion of these units, as well as inactive CCR surface impoundments and legacy CCR surface impoundments.

surface impoundments subject to this proposed rule.

Finally, EPA is proposing a number of technical corrections to the existing regulations, such as correcting certain citations and harmonizing definitions.

EPA intends that the provisions of the rule be severable. In the event that any individual provision or part of the rule is invalidated, EPA intends that this would not render the entire rule invalid, and that any individual provisions that can continue to operate will be left in place.

In this proposal, EPA is not reconsidering, proposing to reopen, or otherwise soliciting comment on any other provisions of the existing CCR regulations beyond those specifically identified in this proposal. For the reader’s convenience, EPA has provided a background description of existing requirements in several places throughout this preamble. In the absence of a specific request for comment and proposed change to the identified provisions, these descriptions do not reopen any of the described provisions. EPA will not respond to comments submitted on any issues other than those specifically identified in this proposal, and such comments will not be considered part of the rulemaking record.

C. What is the Agency’s authority for taking this action?

EPA is publishing this notice under the authority of sections 1008(a), 2002(a), 4004, and 4005(a) and (d) of the Solid Waste Disposal Act of 1970, as amended by the Resource Conservation and Recovery Act of 1976 (RCRA), as amended by the Hazardous and Solid Waste Amendments of 1984 (HSWA) and the Water Infrastructure Improvements for the Nation (WIIN) Act of 2016, 42 U.S.C. 6907(a), 6912(a), 6944, 6945(a) and (d).

RCRA section 1008(a) authorizes EPA to publish “suggested guidelines for solid waste management.” 42 U.S.C. 6907(a). RCRA defines solid waste management as “the systematic administration of activities which provide for the collection, source separation, storage, transportation, transfer, processing, treatment, and disposal of solid waste.” 42 U.S.C. 6903(28).

Pursuant to section 1008(a)(3), the guidelines are to include the minimum criteria to be used by the states to define the solid waste management practices that constitute the open dumping of solid waste or hazardous waste and are prohibited as “open dumping” under section 4005. Only those requirements promulgated under the authority of

section 1008(a)(3) are enforceable under section 7002 of RCRA.

RCRA section 4004(a) generally requires EPA to promulgate regulations containing criteria distinguishing “sanitary landfills,” which may continue to operate, from “open dumps,” which are prohibited. 42 U.S.C. 6944(a); *see id.* 6903(14), (26); 6945(a). The statute directs that, “at a minimum, the criteria are to ensure that units are classified as sanitary landfills only if there is no reasonable probability of adverse effects on health or the environment from disposal of solid wastes at such facility.” 42 U.S.C. 6944(a).

RCRA section 4005(a), entitled “Closing or upgrading of existing open dumps,” prohibits any solid waste management practices or disposal of solid waste that does not comply with EPA regulations issued under RCRA section 1008(a) and 4004(a). 42 U.S.C. 6945(a). *See also* 42 U.S.C. 6903(14) (definition of “open dump”). This prohibition takes effect “upon promulgation” of any rules issued under section 1008(a)(3) and is enforceable either through a citizen suit brought pursuant to section 7002, or through an EPA enforcement action brought pursuant to section 4005(d)(4)(A). *See* 42 U.S.C. 6945(a), (d)(4)(A) (authorizing EPA to use the authority under RCRA section 3008(a) to enforce the open dumping prohibition for CCR). RCRA section 4005 also directs that open dumps (*i.e.*, facilities out of compliance with EPA’s criteria), must be “closed or upgraded.” *Id.*

RCRA section 4005(d)(3) specifies that the regulations in 40 CFR part 257, subpart D “(or successor regulations promulgated pursuant to sections 6907(a)(3) and 6944(a) of this title), shall apply to each CCR unit” unless a permit issued by an approved state or by EPA is in effect. Similarly, section 4005(d)(6)² provides that:

a CCR unit shall be considered to be a sanitary landfill for purposes of this chapter, including subsection (a), only if the coal combustion residuals unit is operating in accordance with [a permit issued by EPA or an approved State] or the applicable criteria for coal combustion residuals units under part 257 of title 40, Code of Federal Regulations (or successor regulations promulgated pursuant to sections 6907(a)(3) and 6944(a) of this title).

1. Regulation of Solid Wastes Under RCRA Subtitle D

Solid wastes that are neither a listed or characteristic hazardous waste are subject to the requirements of RCRA subtitle D. Subtitle D of RCRA

establishes a framework for federal, state, and local government cooperation in controlling the management of nonhazardous solid waste. The federal role is to establish the overall regulatory direction by providing minimum nationwide standards that will protect human health and the environment. States may, but are not required to, adopt these requirements into their state programs.

Under RCRA section 4005(a), upon promulgation of criteria under section 1008(a)(3), any solid waste management practice or disposal of solid waste that constitutes the “open dumping” of solid waste is prohibited. The federal standards apply directly to the facility (are self-implementing) and facilities are directly responsible for ensuring that their operations comply with these requirements.

RCRA section 4005(d) establishes an additional regulatory structure, applicable exclusively to the solid waste management of CCR, that builds on the provisions in sections 1008(a)(3), 4004, and 4005(a), without restricting the scope of EPA’s authority under those sections. *See*, 42 U.S.C. 6945 (d)(7). Under 4005(d), states may seek EPA approval of a state permitting program under which individualized facility permits would “operate in lieu of [EPA] regulation of coal combustion residuals units in the State.” 42 U.S.C. 6945(d)(1)(A). EPA is also directed to “implement a permit program,” which would operate in absence of an approved state program. 42 U.S.C. 6945(d)(2). However, the statute makes clear that facilities must continue to comply with the federal regulations until a permit issued by either EPA or an approved state is in effect. 42 U.S.C. 6945(d)(3), (6).

RCRA sections 1008(a)(3) and 4004(a) delegate broad authority to EPA to establish regulations governing the management of solid waste. Under section 4004(a) EPA is charged with establishing requirements to ensure that facilities will be classified as sanitary landfills and not an open dump “only if there is no reasonable probability of adverse effects on health or the environment from the disposal of solid waste” at the facility. Or in other words, under section 4004(a) EPA is charged with issuing regulations to address all “reasonable probabilities of adverse effects” (*i.e.*, all reasonably anticipated risks) to health and the environment from the disposal of solid waste. Section 1008(a)(3) expands EPA’s authority to address the risks from any of the listed activities. Specifically, EPA is authorized to establish requirements applicable to “storage, transportation,

transfer, processing, treatment, and disposal of solid waste.” (42 U.S.C. 6907(a), 6903(28)). Under RCRA, EPA sets these requirements without taking cost into account as a factor. *See USWAG et al. v. EPA*, 901 F.3d 414, 448–49 (D.C. Cir. 2018) (citing RCRA Section 4004(a)).

The statute is clear that EPA is authorized to issue regulations to address the current risks from previous solid waste management activities. EPA explained at length the basis for this conclusion as part of the Agency’s rationale for regulating inactive impoundments. *See*, 80 FR 21344–21345. *See also USWAG, et al. v. EPA*, 901 F.3d 414 (D.C. Cir. 2018). Among other provisions, the statutory definition of an “open dump” conclusively resolves the question. RCRA defines an “open dump” as “any facility or site where solid waste is disposed of” 42 U.S.C. 6903(14). As the D.C. Circuit explained,

Importantly, while the “is” retains its active present tense, the “disposal” takes the form of a past participle (“disposed”). In this way, the disposal itself can exist (it “is”), even if the act of disposal took place at some prior time Properly translated then, an open dump includes any facility (other than a sanitary landfill or hazardous waste disposal facility), where solid waste still “is deposited,” “is dumped,” “is spilled,” “is leaked,” or “is placed,” regardless of when it might have originally been dropped off. *See* 42 U.S.C. 6903(3), (14). In other words, the waste in inactive impoundments “is disposed of” at a site no longer receiving new waste in just the same way that it “is disposed of” in at a site that is still operating. 901 F.3d at 440. *See also In re Consolidated Consol. Land Disposal Regulation Litig.*, 938 F.2d 1386, 1389 (D.C. Cir. 1991) (EPA’s reading of the term “disposal” in RCRA’s Subtitle C, 42 U.S.C. 6924, to include “the continuing presence of waste” was reasonable); *USWAG*, 901 F.3d at 453–54 (Henderson, J., concurring) (same). By the same logic, these provisions would authorize EPA to regulate closed units that continue to pose risks to health or the environment, for example by requiring the owners and operators of such units to remediate any contamination from these units, or to take action to prevent such contamination.

The 2016 amendments further confirm EPA’s authority over these activities. In section 4005, Congress incorporated the 2015 regulations into the statute, and expressly stated that the amendments in 4005(d) were not intended to limit or restrict the authority already provided under sections 1008(a)(3) and 4004(a). *See*, 42

² 42 U.S.C. 6945(d)(6).

U.S.C. 6945(d)(3), (6), (7). EPA also considers that with these amendments, Congress has affirmed the Agency's authority to impose the kind of requirements established in part 257 (e.g., corrective action to remediate groundwater contamination). Moreover, Congress made clear that EPA retains the authority to modify or expand these requirements as necessary to ensure that the standard in section 4004(a) will continue to be met. See, e.g., 42 U.S.C. 6945(d)(1)(A)(i), (3), (6) (referencing "or successor regulations promulgated pursuant to sections 6907(a)(3) and 6944(a) of this title").

EPA interprets the standard in section 4004(a) to apply equally to criteria issued under sections 1008(a)(3) and 4004(a); namely that the criteria must ensure that a facility is to be classified as a sanitary landfill, and thus allowed to continue to operate, "only if there is no reasonable probability of adverse effects on health or the environment" from either the disposal or other solid waste management practices at the facility. Thus, under the combined authority conferred by sections 1008(a)(3) and 4004(a), a facility is an "open dump" if it engages in any activity involving the management of solid waste that does not meet the standard in section 4004(a); or in other words, any activity involved with the management of solid waste that presents a reasonable probability of causing adverse effects on health or the environment. EPA also interprets these provisions to authorize the establishment of criteria that define the manner in which facilities upgrade or close, consistent with the standard in section 4004(a), to ensure there will be no reasonable probability of adverse effects on health or the environment.

D. What are the incremental costs and benefits of this action?

As noted previously, EPA establishes the requirements under RCRA sections 1008(a)(3) and 4004(a) without taking cost into account. See, *USWAG*, 901 F.3d at 448–49. This action is expected to result in costs amounting to between \$356 million and \$413 million per year when discounting at 3% and 7% respectively.

Of the \$413 million per year estimated at a 7% discount rate, \$237 million is attributable to the requirements for legacy CCR surface impoundments, which are subject to the D.C. Circuit's order in *USWAG*, \$170 million is attributable to the requirements for CCRMU, and \$6 million is attributable to requirements for landfills. Of the \$356 million per year estimated at a 3% rate, \$204

million is attributable to the requirements for legacy CCR surface impoundments, \$146 million is attributable to the requirements for CCRMU, and \$6 million is attributable to requirements for landfills. The costs of this proposed rule are discussed further in the RIA, and include the costs of unit closure, corrective action, fugitive dust controls, structural integrity inspections, and recordkeeping and reporting. These cost estimates are subject to a number of limitations and uncertainties, and EPA has, for example, made the conservative assumption that all closures will be by removal, which is a simplified but higher-cost compliance option.

This action is expected to result in monetized benefits amounting to between \$77 million and \$49 million per year when discounting at 3% and 7% respectively, as well as a variety of unquantified benefits of unknown magnitude. Of the \$49 million in annualized monetized benefits estimated at a 7% discount rate, \$30 million is attributable to the requirements for legacy CCR surface impoundments, \$16 million is attributable to the requirements for CCRMU, and \$3 million is attributable to requirements for landfills. Of the \$77 million in annualized monetized benefits estimated at a 3% discount rate, \$47 million is attributable to the requirements for legacy CCR surface impoundments, \$25 million is attributable to the requirements for CCRMU, and \$5 million is attributable to requirements for landfills. The monetized benefits of this proposed rule are discussed further in the RIA, and includes partial estimates of the benefits from reduced incidents of cancer, avoided intelligence quotient (IQ) losses from mercury and lead exposure and the subsequent reduced need for specialized education, non-market benefits of water quality improvements, and the protection of threatened and endangered species. EPA also monetized the benefits of avoided impoundment failures, including both "catastrophic" failures and smaller-volume releases. One example of a severe impoundment failure is the Dan River Steam Station failure which occurred in 2014, when a stormwater drainage pipe under the inactive surface impoundments at the Dan River Steam Station caused the inadvertent release of 39,000 tons of CCR directly into the nearby Dan River. The result high-end estimate of the costs of this impoundment failure is \$300 million. EPA requests comment and data on other examples of CCR releases from inactive CCR impoundments.

EPA's benefits estimates are subject to a number of limitations and uncertainties, and many key categories of benefits could not be quantified or monetized. Unquantified benefits may be of equal or greater magnitude than quantified benefits but are difficult to quantify because sufficient data or adequate methodologies are not available. For example, EPA was only able to quantify the subset of human health effects for which established dose-response relationships have been studied and accepted for economic analyses. Consequently, EPA was unable to quantify most of the human health and ecological benefits associated with the proposed rule. Specifically, EPA was only able to quantify the benefits associated with: (1) Reduced incidence of two kinds of skin cancer³ from exposure to arsenic III and V in drinking water from private wells, and (2) With reduced neurologic and cognitive damages from exposure to lead and mercury from fish consumption. However, arsenic is also correlated with liver, lung, bladder, and kidney cancer,⁴ all of which are associated with higher costs and higher rates of mortality than the skin cancers used in the quantified benefits assessments. Similarly, toxins such as thallium, molybdenum, and lithium are commonly present in CCR,⁵ and as discussed in Unit IV.B.2 of this preamble, have been detected at statistically significant levels at several utilities, but because EPA lacks the data to create dose-response relationships between ingestion rates and specific health endpoints, EPA could not quantify the associated benefits in the RIA. A broad overview of specific contaminants and their likely health effects can be found in Chapter 4 of the RIA and in Appendix B.

Another unquantified benefit arises from the expected increase in severe weather events due to climate change. Many legacy impoundments and CCRMU are located along rivers or the coast, where they are at risk of leaking waste and possibly failing when severe weather causes the units to flood and overtop. The proposed rule will address this baseline risk by requiring closure

³ EPA evaluated basal cell carcinoma and squamous cell carcinoma, but was unable to quantify costs associated with Bowen's disease (or carcinoma in situ), another of the most common forms of skin cancer.

⁴ U.S. Environmental Protection Agency (2014, December). Human and ecological risk assessment of coal combustion residuals. Regulation Identifier Number: 2050-AE81, citing U.S. EPA. IRIS Chemical Assessment Summary for arsenic, inorganic; CASRN 7440-38-2. Last updated December 3, 2002.

⁵ Id.

and corrective action at legacy units and CCRMU. This reduction in risk yields potentially significant benefits, however the data and methodology to quantify the base rate and post-rule rate of unit leakage and failure due to weather related flooding and overtopping are not available. Thus, this benefit category is unquantified.

Finally, another significant source of unquantified benefits comes from the protection and remediation of the groundwater contaminated by a legacy CCR surface impoundment or CCRMU as at many sites this groundwater is a potential future source of drinking water or other uses. This is distinct from the benefits associated with reducing the risks from contaminants migrating into drinking water wells or surface waters, reduced risks that rely on the presence of a receptor. As EPA explained in the preamble to the original 1979 regulations, sources of drinking water are finite, and future users' interests must also be protected. See, 44 FR 53445–53448.

In the United States, groundwater is the source of drinking water for about half the total population; it is about 33% of the water that County and city water departments supply to households and businesses. It provides drinking water for more than 90% of the rural population who do not get their water delivered to them from a county/city water department or private water company.⁶ It also provides over 50 billion gallons per day for agricultural needs. The volume of available and useable groundwater is decreasing in many areas of the United States.⁷ A significant number of legacy CCR surface impoundments and CCRMU are located in areas that, according to the U.S. Geological Survey (USGS), are experiencing significant groundwater decline and depletion.⁸ For example, EPA estimates that 8 potential legacy CCR surface impoundments are located in Iowa, and 20 potential CCRMU are located in Illinois (12) and Minnesota (8); USGS has estimated that these areas experienced 10–25 cubic kilometers of cumulative annual groundwater depletion between 1900 and 2008.⁹ Simply stated, the resource is becoming more scarce. Commensurately, the value

of groundwater as a resource for agriculture, drinking water, and other purposes is increasing. In the context of such widespread declines in the overall availability of this critical resource, this proposed rule—which will increase the supply of potable water by requiring the remediation of groundwater contaminated by CCRMU and legacy CCR surface impoundments, and by preventing further reductions in the supply of useable groundwater from degradation and contamination from CCRMU or legacy CCR surface impoundments—is expected to provide significant and substantial benefits.

Neighborhoods located near legacy CCR surface impoundments and CCRMU are disproportionately occupied by people already vulnerable to elevated environmental risks. These vulnerable communities face risks of impoundment failure, groundwater contamination, and fugitive air emissions. EPA expects these communities would be afforded substantial protection from the proposed rule. In addition, CCR units, built without liners and other precautionary measures, may depress property values in nearby neighborhoods. Improvements in home values resulting from the proposed rule has the potential to bestow welfare gains to homeowners located near legacy CCR surface impoundments and CCRMU. Although EPA has designed its proposal based on its statutory factors and court precedent and has not relied on this benefit-cost analysis in the selection of its proposed alternative, EPA believes that after considering all unquantified and distributional effects, the public health and welfare gains that will result from the proposed alternative would justify the rule's costs.

Further information on the economic effects of this action can be found in Unit VII of this preamble.

III. Background

A. 2015 CCR Rule

On April 17, 2015, EPA finalized national minimum criteria for the disposal of CCR as solid waste under Subtitle D of RCRA titled, “Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities” (80 FR 21302) (2015 CCR Rule). The 2015 CCR Rule, codified in 40 CFR part 257, subpart D, established regulations for existing and new CCR landfills, as well as existing and new CCR surface impoundments (including all lateral expansions of CCR units). The criteria consist of location restrictions, design and operating criteria, groundwater monitoring and

corrective action requirements, closure and post-closure care requirements, recordkeeping, notification, and internet posting requirements.

The 2015 CCR Rule also imposed requirements on inactive surface impoundments at active facilities. A CCR surface impoundment is a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of CCR and liquids, and treats, stores, or disposes of CCR. The 2015 CCR Rule defined an “inactive CCR surface impoundment” as “a CCR surface impoundment that no longer receives CCR on or after October 19, 2015, and still contains both CCR and liquids on or after October 19, 2015.” 40 CFR 257.53. The rule defined “active facility or active electric utilities or independent power producers” as “any facility subject to the requirements of this subpart that is in operation on October 19, 2015. An electric utility or independent power producer is in operation if it is generating electricity that is provided to electric power transmission systems or to electric power distribution systems on or after October 19, 2015. An off-site disposal facility is in operation if it is accepting or managing CCR on or after October 19, 2015.” 40 CFR 257.53.

The 2015 CCR Rule did not impose any requirements on inactive facilities. EPA explained that this was consistent with past decisions under subtitle C, in which EPA declined to extend permitting obligations to closed and inactive disposal facilities in light of specific language in RCRA sections 3004 and 3005, and the practical difficulties in applying those requirements to inactive facilities (e.g., the difficulty in identifying owners or other responsible parties, and in implementing requirements in the absence of an entity currently engaged in disposal). 80 FR 21344 (April 17, 2015). EPA further raised concerns that the present owner of the land on which an inactive site was located might have no connection (other than present ownership of the land) with the prior disposal activities. *Id.* Consequently, EPA exempted those units at § 257.50(e).

B. 2018 USWAG Decision

The 2015 CCR Rule was challenged by several parties, including coalitions of regulated entities and environmental organizations (“Environmental Petitioners”). Environmental Petitioners raised two challenges that are relevant to this proposal. First, they challenged the provision that allowed existing, unlined surface impoundments to continue to operate until they exceeded

⁶ U.S. Department of the Interior, U.S. Geological Survey, <https://www.usgs.gov/special-topics/water-science-school/science/groundwater-decline-and-depletion>.

⁷ *Id.* at <https://www.usgs.gov/special-topics/water-science-school/science/groundwater-decline-and-depletion>.

⁸ U.S. Department of the Interior, U.S. Geological Survey, Groundwater Depletion in the United States (1900–2008), available at <https://pubs.usgs.gov/sir/2013/5079/SIR2013-5079.pdf>.

⁹ *Id.* at 12.

the groundwater protection standard. *See* § 257.101(a)(1). They contended that EPA failed to show how continued operation of unlined impoundments met RCRA's baseline requirement that any solid waste disposal site pose, "no reasonable probability of adverse effects on health or the environment." 42 U.S.C. 6944(a). Second, Environmental Petitioners challenged the exemption for inactive surface impoundments at inactive power plants (*i.e.*, "legacy ponds"). Environmental Petitioners argued that legacy ponds are at risk of unmonitored leaks and catastrophic structural failures.

On August 21, 2018, the U.S. Court of Appeals for the D.C. Circuit upheld most of the 2015 CCR Rule but decided in favor of Environmental Petitioners on these two claims. The Court held that EPA acted "arbitrarily and capriciously and contrary to RCRA" in failing to require the closure of unlined surface impoundments¹⁰ and in exempting inactive surface impoundments at inactive power plants from regulation. The Court vacated these provisions and remanded the matter back to the Agency for further action consistent with its opinion. *USWAG et al. v. EPA*, 901 F.3d 414 (D.C. Cir. 2018).

In overturning the exemption for legacy ponds, the Court evaluated the evidence in the rulemaking record and reached specific conclusions about the risks that legacy ponds pose. The Court pointed to evidence that legacy ponds are most likely to be unlined and unmonitored and that such units have been shown to be more likely to leak than units at utilities still in operation. 901 F.3d at 432. The Court also determined that legacy ponds:

. . . pose the same substantial threats to human health and the environment as the riskiest Coal Residuals disposal methods, compounded by diminished preventative and remediation oversight due to the absence of an onsite owner and daily monitoring. *See* 80 FR at 21343 through 21344 (finding that the greatest disposal risks are "primarily driven by the older existing units, which are generally unlined"). Notably, this very Rule was prompted by a catastrophic legacy pond failure that resulted in a "massive" spill of 39,000 tons of coal ash and 27 million gallons of wastewater into North Carolina's Dan River.

[T]here is no gainsaying the dangers that unregulated legacy ponds present. The EPA itself acknowledges the vital importance of regulating inactive impoundments at active facilities. That is because, if not properly closed, those impoundments will

"significant[ly]" threaten "human health and the environment through catastrophic failure" for many years to come. 75 FR at 35,177; *see also* 80 FR at 21,344 n. 40.

The risks posed by legacy ponds are at least as substantial as inactive impoundments at active facilities. *See* 80 FR at 21,343–21,344 (finding "no [] measurabl[e] differen[ce]" in risk of catastrophic events between active and inactive impoundments). And the threat is very real. Legacy ponds caused multiple human and environmental disasters in the years leading up to the Rule's promulgation. *See* 75 FR at 35,147 (proposed rule discusses multiple serious incidents). For example, a pipe break at a legacy pond at the Widows Creek plant in Alabama caused 6.1 million gallons of toxic slurry to deluge local waterways. *Id.* Another legacy pond in Gambrills, Maryland caused the heavy metal contamination of local drinking water. *Id.* And the preamble to the Rule itself specifically points to the catastrophic spill at the Dan River legacy pond in North Carolina. 80 FR at 21,393–21,394.

Id. at 432–433. Relying on this evidence, the Court concluded there was no logical basis for distinguishing between the inactive impoundments at active facilities that were regulated and the legacy impoundments that were exempt. *Id.* at 434. Consequently, the Court vacated the provision of the 2015 CCR Rule that specifically exempted inactive impoundments at inactive facilities from regulation and remanded the matter back to EPA for further action consistent with its opinion. *See* § 257.50(e). Notwithstanding the vacatur of § 257.50(e), until EPA amends the regulations to effectuate the Court's order, facilities are not legally obliged to take any action to comply with the federal CCR regulations. This is because, as currently drafted, § 257.50 of the federal CCR regulations is not applicable to inactive surface impoundments at inactive facilities.

C. 2020 Advance Notice of Proposed Rulemaking

On October 14, 2020, EPA published an Advance Notice of Proposed Rulemaking (ANPRM) (85 FR 65015). In that action, EPA requested information related to "legacy" CCR surface impoundments to inform a future rulemaking. The Agency requested input on its regulatory authority, input on a potential definition of a legacy CCR surface impoundment and specific information on the types of inactive surface impoundments at inactive facilities that might be considered legacy CCR surface impoundments. Specifically, EPA requested information on how many of these units exist, the current status of these units (*e.g.*, capped, dry, closed according to state requirements, still holding water), and

the names, locations, and closure dates of former power plants that may have these units. Finally, the Agency took comment on which CCR regulations should apply to legacy CCR surface impoundments and on suggestions for compliance deadlines.

During the 60-day public comment period, the Agency received over 15,000 comments from environmental groups, four states, one tribe, individual utilities, and industry trade associations. The topics raised in comments included a potential definition of a legacy CCR surface impoundment, EPA's regulatory authority, the scope and applicability of the legacy impoundment rule, and regulatory requirements to propose. Moreover, the comments generally agreed that EPA must prescribe timeframes for coming into compliance with the regulations and they recommended timeframes that are shorter than compliance timeframes in the 2015 CCR Rule. The remaining comments received are discussed in subsequent units of this preamble.

As noted, EPA took comment on whether, in light of the Court's opinion in *USWAG*, the Agency could reconsider whether it has the authority to regulate inactive impoundments under RCRA subtitle D. 85 FR 65017–65018 (Oct 14, 2020). The general consensus from commenters on the ANPRM was that, because the Court resolved the question based on the plain meaning of the statute, EPA does not have the discretion to reinterpret its authority. In addition, no commenter identified a factual basis for not regulating legacy CCR surface impoundments that addressed the Court's concern about the risks these units pose. *Id.* at 65018. Consequently, EPA is not revisiting the question of whether it may regulate inactive or legacy CCR surface impoundments.

IV. What is EPA Proposing?

In response to the *USWAG* decision, EPA is proposing to include a provision at § 257.50(e), specifying that inactive surface impoundments at inactive facilities ("legacy CCR surface impoundments") are subject to 40 CFR part 257, subpart D. EPA is also proposing that owners and operators of legacy CCR surface impoundments comply with all the appropriate requirements applicable to inactive CCR surface impoundments at active facilities. Specifically, EPA is proposing that owners and operators of legacy CCR surface impoundments comply with the following existing requirements in the CCR regulations: structural stability assessments, air criteria, inspections,

¹⁰ The closure of unlined CCR surface impoundments was addressed in a separate regulatory action that was published on August 28, 2020 (85 FR 53516).

groundwater monitoring and corrective action, closure and post-closure care, recordkeeping, and notification and publicly accessible internet site requirements. EPA is further proposing to establish different compliance deadlines for these newly applicable regulatory requirements to ensure the owners and operators of these units have time to come into compliance.

In addition to the revisions EPA is proposing to address the *USWAG* decision, EPA is proposing to establish requirements to address the risks from currently exempt solid waste management that involves the direct placement of CCR on the land.¹¹ EPA is proposing to extend a subset of the existing requirements in part 257, subpart D to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR Rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. In this proposal, EPA refers to these as CCR management units, or CCRMU. This proposal would apply to all existing CCR facilities and all inactive facilities with legacy CCR surface impoundments subject to this proposed rule.

Lastly, EPA is proposing to make several technical corrections to the CCR regulations. These are (1) to clarify the definitions of “feasible” and “technically feasible”; (2) to correct the CFR reference in the definition of wetlands at § 257.61(a); (3) to correct a reference in the groundwater monitoring scope section; (4) to standardize the references to CCR websites throughout the CCR regulations; and (5) EPA is taking comment on extending the period for document retention and posting.

A. Legacy CCR Surface Impoundment Requirements

The Agency is proposing that the existing requirements of the CCR regulations in 40 CFR part 257, subpart D that apply to inactive CCR impoundments at active facilities would apply to legacy CCR surface impoundments, except for the location restrictions and liner design criteria. EPA is also proposing to establish new requirements to address issues specific to legacy CCR surface impoundments. Finally, EPA is proposing to establish new compliance deadlines for legacy CCR surface impoundments.

1. Scope—Definition of Legacy CCR Surface Impoundments

EPA received numerous comments on three options for defining legacy CCR surface impoundments in the ANPRM. The Agency considered those comments, as well as the other information available to EPA in the record and the *USWAG* decision in developing this proposal. Based on EPA’s review, the Agency is proposing to define a *legacy CCR surface impoundment* as “a surface impoundment that is located at a power plant that ceased generating power prior to October 19, 2015, and the surface impoundment contained both CCR and liquids on or after the effective date of the 2015 CCR Rule (*i.e.*, October 19, 2015).” This Unit of the preamble also responds to comments questioning how EPA intends to interpret “contains liquids and CCR” and “inactive facility.”

a. Legacy CCR Surface Impoundment—Date for Determining Applicability.

As previously explained, the 2015 CCR Rule exempted “inactive surface impoundments at an inactive facility” and provided definitions of an “inactive CCR surface impoundment” and an “active facility or active electric utility.” See 80 FR 21469–21471. Thus, in developing a definition of a *legacy CCR surface impoundment* two separate components need to be addressed: (1) The definition of an “inactive CCR surface impoundment,” and (2) The definition of an “inactive facility or electric utility.” EPA relied on the existing definitions of an inactive CCR surface impoundment and an active facility or active electric utility, as well as the *USWAG* decision to inform the options provided in the ANPRM. See 80 FR 21469–21471. Specifically, both terms establish applicability based in part on the effective date of the 2015 CCR Rule—a unit is an “inactive CCR surface impoundment” if it does not receive CCR on or after October 19, 2015, and still contains both CCR and liquids on October 19, 2015, and an “active facility or active electric utilities or independent power producers” is only active if it was in operation on October 19, 2015. 40 CFR 257.53. Thus, the ANPRM sought comment on whether to define a legacy CCR surface impoundment as: A surface impoundment that is located at a power plant that ceased generating power prior to October 19, 2015, and

• Option 1—the surface impoundment contained both CCR and liquids on the effective date of the 2015 CCR Rule (*i.e.*, October 19, 2015); or

• Option 2—the surface impoundment contained both CCR and liquids on the date the Court issued its mandate for the August 21, 2018, court decision (*i.e.*, October 15, 2018); or

• Option 3—the surface impoundment contains both CCR and liquids on the date EPA issues a final rule bringing legacy CCR surface impoundments under the federal regulations.

i. Description of the ANPRM Options

Option 1 was based on October 19, 2015, which is the effective date of the 2015 CCR Rule. Under this approach a CCR surface impoundment at an inactive facility or electric utility that contained both CCR and liquids on October 19, 2015, would be regulated as a legacy CCR surface impoundment. Impoundments that contained both CCR and liquids prior to October 19, 2015, but not after this date, would not be subject to the new requirements under this option (*e.g.*, the facility took actions prior to October 19, 2015, to permanently remove liquids from the unit).

The first option is based on the Court’s finding in the *USWAG* decision that there was no basis in the record on which to differentiate between legacy CCR surface impoundments and inactive CCR surface impoundments at active facilities in the 2015 CCR Rule. In the decision, the Court concluded there was no logical basis for distinguishing between inactive impoundments at active facilities that were regulated and inactive impoundments at inactive facilities that were exempt, and therefore vacated the exemption for legacy CCR surface impoundments in § 257.50(e). In the regulations, an inactive CCR surface impoundment at an active facility is defined as a “CCR surface impoundment that no longer receives CCR on or after October 19, 2015, and still contains both CCR and liquids on or after October 19, 2015.” Thus, under Option 1 the date the unit contained both CCR and liquids used in the definition of a legacy CCR surface impoundment would be identical to that used for inactive impoundments at active facilities, that is, October 19, 2015.

Option 2 was based on October 15, 2018, which is the date the Court issued the mandate for the *USWAG* decision that vacated and remanded the regulatory provision exempting legacy CCR surface impoundments from the CCR regulations. Under this approach a CCR surface impoundment at an inactive facility or electric utility that contained both CCR and liquids on October 15, 2018, would be regulated as

¹¹ Regulated CCR units consist of new and existing landfills and surface impoundments, including any lateral expansion of these units, as well as inactive CCR surface impoundments and legacy CCR surface impoundments.

a legacy CCR surface impoundment. Impoundments that contained both CCR and liquids prior to October 15, 2018, but not after this date, would not be subject to the new requirements under this option (e.g., the facility took actions prior to October 15, 2018, to permanently remove liquids from the unit).

Option 3 was based on the effective date of a final rule bringing legacy CCR surface impoundments under the federal CCR regulations. Under this approach a CCR surface impoundment at an inactive facility or electric utility that contained both CCR and liquids on the effective date of the final rule would be regulated as a legacy CCR surface impoundment. Impoundments that contained both CCR and liquids prior to the effective date of the final rule, but not after this date, would not be subject to the new requirements.

Underpinning *Option 3* is the concept that it may be difficult for some owners and operators of inactive facilities to determine whether a legacy CCR surface impoundment at its facility previously contained both CCR and liquids at a specific point in the past. For example, under *Options 1* and *2*, the demarcation date in the definition will be approximately nine and six years in the past, respectively, at the time the final rule is anticipated to be published and effective. Furthermore, the third option could eliminate possible regulatory confusion for legacy CCR surface impoundments that contained liquids and CCR on the demarcation date specified in the definition (e.g., October 19, 2015, under *Option 1*) but are subsequently closed by the effective date of the final rule. An example of this situation using a cutoff date based on *Option 1* would be a legacy CCR surface impoundment that was closed by removal of CCR in 2020. Under *Option 3* the legacy CCR surface impoundment in this example would not be subject to the new rulemaking requirements because it did not contain both CCR and liquids on or after the effective date of the legacy CCR surface impoundment final rule.

Of the three options discussed in the ANPRM, EPA believes that *Option 1* is arguably the most consistent with the *USWAG* decision and the most protective option. As discussed in the preceding Unit, the Court expressly found that EPA's record for the 2015 CCR Rule demonstrated that legacy ponds "pose the same substantial threats to human health and the environment as the riskiest Coal Residuals disposal methods, compounded by diminished preventative and remediation oversight

due to the absence of an on-site owner and daily monitoring." 901 F.3d at 432. Under *Option 1* there would be no distinction between legacy CCR surface impoundments and the currently regulated inactive impoundments at active facilities. In addition, the intended effect of a vacatur is to restore the status quo, to what it would have been if the vacated provision had never existed. Here, that means legacy CCR surface impoundments would have been regulated by the 2015 CCR Rule. By choosing to vacate the provision, rather than remanding it back to the Agency, the Court made clear that its intent was for these units to immediately be subject to regulation. The fact that the vacatur did not achieve that does not change the court's intent.

ii. What comments did EPA receive on the options?

Summary of Comments on Option 1. Some commenters stated that inactive surface impoundments at inactive facilities should be treated no differently than active and inactive surface impoundments at active facilities. These commenters therefore supported *Option 1* and explained that the regulations should similarly apply to inactive impoundments at inactive facilities containing CCR and liquids on October 19, 2015. Other commenters opposed *Option 1* because they considered that it would represent the retroactive application of regulations and, in some cases, the application of fundamentally inapplicable requirements to units that are no longer surface impoundments because they no longer contain CCR and/or liquids. These commenters identified impoundments that have been dewatered, excavated, and closed pursuant to state oversight as an example of impoundments that would not be appropriate candidates for subsequent regulatory requirements because these units are no longer functioning as impoundments based on actions taken by facilities since October 19, 2015.

Other commenters stated that the definition for *Option 1* (as well as *Options 2* and *3*) was too narrow and fails to address the universe of inactive impoundments at inactive facilities that pose a reasonable probability of adverse effects on health or the environment from the disposal of CCR. According to the comments, this is because *Option 1* conditions regulation of legacy CCR surface impoundments on arbitrary dates on which the impoundments contained both CCR and liquids. These commenters stated that the definition must include high-risk impoundments

(such as impoundments located in floodplains and unstable areas and units with bases inundated by groundwater), regardless of age or condition, because of the likelihood that they are causing or will cause adverse effects to health and the environment, including impoundments located in floodplains and unstable areas and units with bases inundated by groundwater. In addition, the commenters state that the definition of a legacy CCR surface impoundment must include units that were not closed in a manner consistent with the regulations because a unit without a sufficient final cover system will allow precipitation into the unit and will produce leachate.

Summary of Comments on Option 2. No commenters exclusively supported *Option 2* over the other two options discussed in the ANPRM. Commenters disfavoring *Option 2* did so for the same reasons as summarized for *Option 1*, largely stating that *Option 2* ignores the current status of legacy CCR surface impoundments, inaccurately assesses current risks from these units, and disregards work and actions taken by facilities since August 21, 2018 (e.g., removal of waste from the units, closure of the units). In addition, other commenters stated that *Option 2* fails to meet the RCRA protectiveness standard for reasons discussed under *Option 1*.

Summary of Comments on Option 3. Several commenters supporting *Option 3* stated that the definition of legacy CCR surface impoundments should be based on the scope of units identified in the 2018 *USWAG* decision. These commenters explained that the Court was concerned with the risks associated with lack of regulatory oversight over inactive CCR surface impoundments that contain impounded water, and therefore EPA's definition of a legacy CCR surface impoundment should similarly be those impoundments containing CCR and liquids on the effective date of the legacy CCR surface impoundment final rule. Finally, commenters stated that it is both impractical and unnecessary to look backwards to determine the historic regulatory status of a unit (e.g., to determine whether the impoundment contained CCR and liquids at a particular time), or to require impoundments that have already closed to re-close under this rulemaking.

Some commenters said that *Option 3* would avoid inclusion of effectively dry impoundments that are similar to inactive CCR landfills, which are not regulated under the 2015 CCR Rule. Another commenter stated that units maintained by its members provide good examples of units that it believed

would not be appropriate candidates for new federal CCR regulation as legacy CCR surface impoundments. For instance, the commenter pointed to the units at the Riverbend Steam Station in Mount Holly, North Carolina, which the commenter stated underwent dewatering from 2014 through 2019 as part of the excavation process. In accordance with the facility's NPDES permit, the water was pumped to the on-site wastewater treatment facility for eventual discharge to the adjacent waterbody. Ash removal began in 2015 and was completed in 2019. The two ash basins at the Riverbend Steam Station have been excavated, and the dams for the facility's primary and secondary ash basins have been removed. According to the commenter, groundwater monitoring subject to state regulations and state-approved closure plans is ongoing. Finally, the commenter stated that the site has been regraded and seeded with grass. The commenter also pointed to Scholz Electric Generating Plant in Sneads, Florida, which has a 40-acre unit that was retired in April 2015 and ceased receipt of waste in 2015. According to the commenter, the facility is currently in its third year of closure construction and is subject to a June 2015 court-approved settlement agreement for closure as well as an August 2016 closure plan approved by the Florida Department of Environmental Protection.

The commenter also referenced the ash slurry settling ponds at the active Coronado Generating Station located in Saint Johns, Arizona. According to the commenter, the ponds, which are approximately 87 acres in size, were constructed in the mid-2000s and operated until early 2010 when the facility ceased placement of CCR material in the ponds. When in use, the ponds were utilized for CCR and non-CCR waste disposal, non-recyclable plant wastewater, scrubber sludge, and fly ash, all of which were wet sluiced to the ponds. The commenter stated that closure of the ponds was completed in April 2019 in accordance with all applicable State of Arizona Aquifer Protection Permitting (APP) rules, and all required CCR and APP documentation have been posted to the CCR public website and submitted to the Arizona Department of Environmental Quality (ADEQ). The commenter also stated that the ponds are currently in post-closure care in accordance with ADEQ APP regulations, including groundwater monitoring and reporting that will continue for 30 years from the date of closure. According to

the commenter, none of these units are currently functioning as ponds, and therefore regulating these types of units at inactive plants would represent a retroactive application of inapplicable and redundant requirements. The commenter further stated that many utilities are in the process of dewatering and closing additional legacy CCR surface impoundments as part of a comprehensive, fleetwide ash basin closure program.

iii. Response to Comments and Proposed Option

As noted above, the Agency is proposing to define a legacy CCR surface impoundment, in part, as a surface impoundment that contained both CCR and liquids on or after October 19, 2015. Of the three options discussed in the ANPRM, EPA believes that Option 1 is the most consistent with the *USWAG* decision. As discussed in the preceding Unit, the Court expressly found that EPA's record for the 2015 CCR Rule demonstrated that legacy ponds "pose the same substantial threats to human health and the environment as the riskiest Coal Residuals disposal methods, compounded by diminished preventative and remediation oversight due to the absence of an on-site owner and daily monitoring." 901 F.3d at 432. Under Option 1 there would be no distinction between legacy CCR surface impoundments and the currently regulated inactive impoundments at active facilities. In addition, the intended effect of a vacatur is to restore the status quo, to what it would have been if the vacated provision had never existed. Here, that means legacy CCR surface impoundments would have been regulated by the 2015 CCR Rule. By choosing to vacate the provision, rather than remanding it back to the Agency, the Court made clear that its intent was for these units to immediately be subject regulation. The fact that the vacatur did not achieve that does not change the Court's intent.

In addition, EPA is not persuaded by the commenters' objections to this option. EPA disagrees that reliance on the effective date of the 2015 CCR Rule would constitute a retroactive application of law. For a regulation to be retroactive, it must change the prior legal status or consequences of past behavior. See *Landgraf v. USI Film Products*, 511 U.S. 244, 269, n.4 (1994) (A rule "is not made retroactive merely because it draws upon antecedent facts for its operation."); *Treasure State Resource Industry Ass'n v. E.P.A.*, 805 F.3d 300, 305 (D.C. Cir. 2015). By contrast, here EPA is merely proposing

to rely on a past fact to support the future application of regulations. And because EPA is proposing to establish future compliance dates, no facility would be subject to penalties solely because one of its legacy CCR surface impoundments was out of compliance with the regulatory requirements prior to the effective date of a rule finalizing this proposal.

EPA also disagrees that the proposed requirements fail to account for the current characteristics of some of these units. The fact that some utilities have begun to close, or even completed closure does not necessarily resolve the risks these units can pose to groundwater. The record shows that significant numbers of CCR surface impoundments were constructed such that the base of the unit intersects with groundwater, and that many "closed" impoundments, even those closed in accordance with state permits, continue to impound water below the water table (*i.e.*, contain liquid). The risks associated with such closures can be substantial (see Unit IV.B.1.b of this preamble for more information). Also, as discussed below in further detail, EPA is proposing that units that can demonstrate that they have met the performance standards for closure by removal in § 257.102(c) would be subject to no further requirements.

Finally, EPA recognizes that in some instances it may take some work to determine whether a surface impoundment previously contained both CCR and liquids on or after October 19, 2015. However, owners and operators of inactive power plants will be able to rely on operating records from when the power plant was operational, such as aerial photography, construction or inspection reports, groundwater monitoring data and employee testimonials to determine whether the impoundment contained both CCR and liquids on October 19, 2015.

Nevertheless, EPA also continues to consider, as an alternative, defining a legacy CCR surface impoundment as a CCR surface impoundment that no longer receives CCR but contains both CCR and liquids on or after the effective date of the final rule. This option would be the easiest to implement. Based on the Agency's interpretation of what it means "to contain liquid" this option would at most only exclude the 29 units¹² that may have completed clean closure in accordance with the performance standards in § 257.102(c) or have taken steps to remove all free

¹² This information can be found in the document titled "Potential Legacy CCR Surface Impoundments" in the docket for this action.

liquids, including groundwater, and address infiltration, and would therefore be equivalent to inactive landfills. While the latter category could still present the risk of contaminating groundwater, it is possible those risks could potentially be addressed by the proposed expansion of groundwater monitoring, corrective action, and closure obligations applicable to CCR management units. EPA therefore requests further comment on this option.

b. Legacy CCR Surface Impoundment—Contains Both Liquid and CCR

In response to EPA's ANPRM, some commenters stated that the phrase "contain[ing] both CCR and liquids" is impermissibly vague. These commenters believe that while it is clear that impoundments that currently contain visible, standing water would fit this definition, they are concerned that arguments can be made that the definition does not include those units whose bases are in contact with groundwater or that no longer have standing water at the surface. Other commenters stated that more clarity is required regarding the definition of a legacy CCR surface impoundment. Finally, several commenters argued that EPA should not limit its regulation to units that contain water, but should expand the regulation to apply to all CCR units.

i. What does it mean to contain liquid?

The ANPRM suggested that EPA would only revisit the date on which the determination would be made as to whether the impoundment contains both CCR and liquids. EPA did not indicate that the Agency intended to propose to limit or revise the existing requirement that in order to be considered an inactive CCR surface impoundment, the unit must contain both liquid and CCR. 40 CFR 257.53. However, as noted above, commenters have raised concerns that the existing definition is ambiguous and have raised questions about how these existing regulations apply to a number of factual scenarios. Specifically, commenters questioned whether the term "liquids" includes free water, porewater, standing water, and groundwater in CCR units.

The part 257 regulations do not include a definition of the term "liquids." 40 CFR 257.53. Neither does RCRA define the term. *See*, 42 U.S.C. 6903. EPA therefore relies upon dictionary definitions to interpret the regulation. For example, Merriam-Webster defines it as "a fluid (such as water) that has no independent shape but has a definite volume and does not

expand indefinitely and that is only slightly compressible." Similarly, liquid (in physics) can be defined as one of the three principal states of matter, intermediate between gas and solid. The most obvious physical properties of a liquid are its retention of volume and its conformity to the shape of its container. Liquid can flow, and when a liquid substance is poured into a container or vessel, it takes the shape of that vessel, and will remain that way if conditions are unchanged (*e.g.*, the substance stays in the liquid state). Furthermore, when a liquid is poured from one vessel to another, it retains its volume (if there is no vaporization or change in temperature) but not its shape. These properties serve as useful criteria for distinguishing the liquid state from the solid and gaseous states.

In the realm of CCR surface impoundments, several types of liquids may be present in a CCR unit. For example, among others, this may include water that was sluiced into the impoundment along with the CCR, which may be found as free water ponded above the CCR or porewater intermingled with the CCR, or surface water and groundwater that has migrated into the impoundment due to the construction of the unit. Based on the regulatory terms, the structure, and context in which the terms are employed, as well as the dictionary definitions of "liquid," above, and the fact that nothing in the regulatory definition limits the source of the liquid, EPA considers free water, porewater, standing water, and groundwater to be liquids under the existing regulation. Moreover, the source of the liquid is not important with respect to its basic and fundamental designation as a liquid. It therefore does not matter whether the liquid in the surface impoundment comes from the rain, waters the facility deliberately places in the unit, floodwaters from an adjacent river, or from groundwater—all are liquids, and once present in the unit, they have the same potential to create leachate (another type of liquid), as well as to contribute to hydraulic head and drive flows driven by hydraulic gradients.

Commenters questioned whether the existing definition of an inactive CCR surface impoundment would cover a surface impoundment where, prior to October 19, 2015, the facility has decanted the surface water, but, because the base of the impoundment intersects with the aquifer, water continues to flow through the impoundment and permeate the waste in the base of the unit. Commenters also questioned whether any of the following would also

be covered: (a) Impoundments that contained CCR and liquids in the past but are now closed, (b) Impoundments that contained CCR and liquids in the past but will be in the process of closing by the effective date of the legacy rulemaking, and (c) Impoundments that once contained CCR and liquids but have been fully dewatered and are now maintained so as to not contain liquid.

The critical issue in these questions is whether on or after the relevant date in the regulation these units "contain" liquid. "Contains" means "to have or hold (someone or something) within" (*e.g.*, Oxford English Dictionary, Merriam-Webster). Accordingly, an impoundment "contains" liquid if there is liquid in the impoundment, even if the impoundment does not prevent the liquid from migrating out of the impoundment. In other words, it "contains" water if it *has* water within, even if it does not completely restrain the water within the unit.

A surface impoundment that, on or after October 19, 2015, has only decanted the surface water would normally still contain liquid if waste is saturated with water. To the extent the unit still contains liquids, it would be covered by the existing definition of an inactive impoundment. Under this proposed rule, such units would also be considered legacy CCR surface impoundments when located at inactive facilities. This would apply whether the unit is considered "closed" under state law, is in the process of closing, or whether at some subsequent point, the unit is fully dewatered and no longer contains liquid.

To determine whether an impoundment has only been partially dewatered, EPA relies on the dewatering requirement found in the closure performance standard at § 257.102(d)(2)(i) ("Free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues"). Both the definition of an inactive CCR surface impoundment and the closure performance standard are designed to address the same issues (the presence or removal of liquid wastes) and are designed for the same purpose (to ensure the risks from the co-management of CCR and liquid are adequately addressed). Under the closure performance standard, a facility must eliminate both the standing liquid in the surface of the impoundment and the separable porewater in any sediment located in the base of the impoundment. Free liquids are defined at § 257.53 to mean "liquids that readily separate from the solid portion of a waste under ambient temperature and pressure." This definition encompasses both

standing liquids in the impoundment as well as porewater in any sediment or CCR. The regulation does not differentiate between the sources of the liquid in the impoundment (*e.g.*, surface water infiltration, sluice water intentionally added, groundwater intrusion). This is further supported by the fact that the performance standard at § 257.102(d)(2)(i) was modeled on the regulations that apply to interim status hazardous waste surface impoundments, which are codified at § 265.228(a)(2)(i). Available guidance on these interim status regulations clarifies that these regulations require both the removal of standing liquids in the impoundment as well as sediment dewatering. See “Closure of Hazardous Waste Surface Impoundments,” publication number SW-873, September 1982. See also, Final Decision on Request For Extension of Closure Date Submitted by Gavin Power, LLC, 87 FR 72989 (November 15, 2022).

Accordingly, units that contain both CCR and liquids from any source, including those specifically identified above, after the relevant date would be considered inactive CCR impoundments, consistent with the existing regulations. Although EPA considers that the term “liquids” is sufficiently clear that a definition is not necessary, EPA requests comment on whether it would be useful to include a regulatory definition of liquids.

Under the existing regulations, an impoundment that did not contain liquids prior to the effective date of the 2015 CCR Rule, whether because it was closed in accordance with existing state requirements or for other reasons, is not an inactive impoundment. Similarly, a unit that still contains CCR and liquid after the relevant effective date would still be considered an inactive unit even if it was closed in accordance with the requirements in effect at the time (*e.g.*, has a cover). EPA is not proposing to revise this for inactive impoundments, and for consistency, EPA is proposing that the same would hold true for legacy CCR surface impoundments, whatever date EPA ultimately selects for the definition.

However, EPA also received comments in response to the ANPRM stating that available groundwater monitoring data demonstrates that CCR landfills (whether active or inactive) are just as likely to contaminate groundwater as CCR surface impoundments (legacy or otherwise). Accordingly, the commenters argue that EPA should regulate all CCR units, without regard to whether they contain liquid.

EPA is not proposing to expand the definition of a legacy CCR surface impoundment to include units that contain no liquid. Units that contain liquid present different risks than those that do not, and the applicable requirements should differentiate among them accordingly on that basis. While EPA acknowledges that inactive landfills can still present the risk of contaminating groundwater, it is possible those risks could potentially be addressed by this rule’s proposed expansion of groundwater monitoring, corrective action, and closure obligations to CCR management units. EPA acknowledges that its current proposal would not regulate every inactive CCR landfill, *e.g.*, it would not address any inactive landfill located at an inactive utility that did not also have an inactive CCR surface impoundment, but it is unclear how many of such units exist, and whether there are any reasons that the risks from these units may differ from those that EPA is proposing to regulate. EPA therefore requests comment on these issues.

i. What does it mean to “contain” CCR?

Under the existing regulation, an inactive CCR surface impoundment must contain CCR to be subject to the rule. 40 CFR 257.53. EPA is not proposing to revise that aspect of the term’s definition. Consequently, EPA is proposing that a legacy impoundment that has closed by removal in accordance with the performance standards in § 257.102(c) before the relevant date would not be considered an inactive CCR surface impoundment. EPA is proposing that facilities with such a unit would only be required to post documentation that they have met the existing standard for closure by removal in § 257.102(c) on their CCR website. EPA is also proposing, however, that an impoundment at an inactive facility still undergoing closure by removal on the relevant date would be considered a legacy CCR surface impoundment subject to the final rule requirements. Depending on when the impoundment completes closure, some individual requirements may no longer be applicable to the legacy CCR surface impoundment (*i.e.*, when the compliance date in the final rule falls after the date closure is completed for the impoundment); but EPA has no basis for concluding that a legacy CCR surface impoundment that is still in the process of closing poses no risk.

A commenter asserted that EPA’s authority under RCRA only extends to those impoundments where solid waste is still being “disposed of” at such inactive sites. According to the

commenter, EPA’s authority ends once the solid waste is removed from the inactive impoundment. The commenter cites the *USWAG* decision to support this interpretation, noting that the Court states that an impoundment regulated under RCRA includes:

any facility . . . where solid waste still “is deposited,” “is dumped,” “is spilled,” “is leaked,” or “is placed,” regardless of when it might have originally been dropped off.” See 42 U.S.C. 6903(3), (14). . . . A site where garbage “is disposed of” is the place where garbage is dumped and left. The status of the site does not depend on whether or not more garbage is later piled on top. A garbage dump is a garbage dump until the deposited garbage is gone.

The commenter concludes that, following the Court’s logic, a legacy CCR surface impoundment is regulated under RCRA because CCR is currently deposited and stored at the site, but it remains an impoundment regulated under RCRA only during the time CCR is actually being stored at the site. According to the commenter, once all the CCR is removed from the impoundment and the impoundment site has achieved clean closure status according to state regulators, no CCR is being disposed as a solid waste at the site and consequently the impoundment is no longer subject to federal CCR regulation under Subtitle D of RCRA. By contrast, another commenter relied on the *USWAG* decision to conclude that EPA must regulate all legacy CCR surface impoundments unless the facility demonstrates that the unit has complied with the requirements in § 257.102(c). According to the commenter, the Court explained that “the statute creates a binary world: A facility is a permissible sanitary landfill, or it is an impermissible open dump. The EPA regulates both. The timing or continuation of disposal is irrelevant.”

EPA agrees that it no longer has jurisdiction over a former unit that has closed by removal in accordance with § 257.102(c). Once those standards have been met, no CCR “‘still ‘is deposited,’ ‘is dumped,’ ‘is spilled,’ ‘is leaked,’ or ‘is placed.’” This is consistent with EPA’s proposal to require the owner or operator to document that the unit has closed in accordance with § 257.102(c), but to impose no requirements on such units.

Nevertheless, EPA is unable to accept the suggestion that EPA exempt legacy CCR surface impoundments that have met state requirements for clean closure. The commenter did not provide any information about any of the state requirements they reference, or otherwise provide information that would allow EPA to evaluate how the

individual state requirements compare to § 257.102(c). Based on the current record EPA can only support a determination that units that have clean closed since 2015 under a state CCR permit program meet the closure requirements in § 257.102(c) for those facilities operating under a permit issued pursuant to one of the three approved state CCR permit programs (Oklahoma, Georgia, and Texas). Moreover, in RCRA section 4005(d)(1) Congress established specific standards and mandated the process for EPA to determine that state requirements should operate in lieu of the federal. Under those provisions, a state can apply to obtain authorization from EPA to operate its program (either in whole or in part) in lieu of the federal requirement by demonstrating that either of the standards in RCRA section 4005(d)(1)(B) has been met. Relying on that congressionally mandated process, rather than this rulemaking, is the appropriate route to address the commenters' concerns about duplication between federal and state requirements.

EPA acknowledges that since the 2015 CCR Rule and the *USWAG* decision some units have closed or have begun to close in accordance with state permits. The Agency is also aware of units that closed on their own initiative in response to the D.C. Circuit's ruling. In response to the ANPRM, EPA received information that since October 19, 2015, 22 surface impoundments at inactive facilities have closed by removal, and 27 surface impoundments have closed with waste in place, either with oversight from a state agency or on their own initiative in response to the *USWAG* decision. A number of commenters claimed that their units are heavily vegetated or developed and that reopening or other removal/remediation activities may disrupt current use of the land. It may well be that some old units are heavily vegetated. However, no commenter submitted any data or analysis to demonstrate that, over the long term, removal or remediation activities would be more detrimental to health and the environment than either cleaning up the contaminated groundwater or taking measures to prevent the legacy CCR surface impoundment from contaminating groundwater.

Moreover, the fact that some impoundments have become heavily vegetated or redeveloped does not resolve the risks these unlined legacy CCR surface impoundments continue to pose. At a minimum, the record shows that significant numbers of CCR surface impoundments were constructed such

that the base of the unit intersects with groundwater, and that many inactive, or even "closed," impoundments continue to impound water below the water table (*i.e.*, contain liquid). The risks associated with such closures can be substantial. See Unit IV.B.1.b of this preamble for more information. Consequently, based on the current record, EPA could not support an exemption for units that still contain both liquid and CCR even if the closure or remediation may disrupt the current use of the land.

c. Inactive Facility

Consistent with *USWAG*, EPA is proposing to regulate all inactive CCR surface impoundments at inactive utilities. To support this decision, EPA is proposing to define an inactive utility (or inactive facility) as one that ceased producing electricity prior to October 19, 2015. This date is the effective date of the 2015 CCR Rule. This is also the same date currently used in the regulation to define "active facility," and that EPA originally used to define the exempted units. Use of this date would mean that the same universe of units that were subject to the original exemption would be regulated. This is consistent with the Court's vacatur, as vacatur is intended to restore the status quo ante, as though the vacated provision never existed.

This definition is important to identify which facilities have legacy CCR surface impoundments and therefore are subject to these proposed regulations. EPA is relying on the existing rulemaking record and provisions in § 257.50(b) to draw conclusions about the production of power such that an inactive facility contains "units that dispose or otherwise engage in solid waste management of CCR generated from the combustion of coal at electric utilities and independent power producers," and from § 257.50(c), which says "electric utilities or independent power producers, regardless of the fuel currently used at the facility to produce electricity." EPA is also relying on the existing definition of "facility" which means "all contiguous land, and structures, other appurtenances, and improvements on the land, used for treating, storing, disposing, or otherwise conducting solid waste management of CCR. A facility may consist of several treatment, storage, or disposal operational units (*e.g.*, one or more landfills, surface impoundments, or combinations of them)."

Ownership and the ability to identify those responsible for complying with these regulations is a key consideration

for the proposed definition of an inactive facility. EPA analyzed the list of inactive CCR facilities provided in the ANPRM comments and conducted additional research to determine the owner of those facilities. To identify the owners of legacy CCR surface impoundments, EPA conducted a two-tiered research process. First, EPA conducted a general search that included desktop research, with a focus on news articles and trade publications regarding plant closures and ownership transfers, to identify the most recent identified owner of each former plant. Where possible, EPA confirmed the findings with utility websites, which often contain information on retired or converted plants, and often have corporate timelines that identify transfer of properties to other parties. In addition, where possible, when EPA identified an owner, the Agency attempted to confirm that the property or plant was listed on the owner's website. If information could not be confirmed, EPA continued researching until all other entities that could potentially currently own the plant could be ruled out. Second, EPA ran these identified owners through the Dun & Bradstreet Hoover's database to identify the ultimate corporate parent of the identified owner. The 156 legacy CCR surface impoundments on the list are associated with 37 different unique corporate parents. Of the 156, the vast majority, 126, are owned by a set of 23 companies the Agency knows own facilities regulated by the CCR regulations. The remaining 30 units are owned by 14 different companies, with each company generally having just one location/site with legacy CCR surface impoundments (with one exception, that owns two sites). Therefore, it appears that most of the inactive facilities are owned by companies that are already regulated by the CCR regulations. Some of them are owned by a company that is not currently regulated by the CCR regulations, but the company has at least one facility with potential legacy CCR surface impoundments. EPA has not identified any facilities where the owner cannot be determined.

In the ANPRM, EPA solicited comments about innocent owners of inactive facilities, but several commenters said that unlike the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), RCRA does not contain an "innocent owner" concept, and there is therefore no statutory basis for uniformly excluding these owners from any RCRA regulations applicable to

legacy CCR surface impoundments. The same commenter said the owner should be the owner at the time of rule promulgation and that owner would be in a position to make decisions and act in response to new regulatory requirements applicable to the legacy CCR surface impoundments. Based on EPA's analysis of inactive facility ownership, EPA has no factual basis to establish an innocent owner provision and therefore is not proposing one.

A commenter suggested that EPA should use the phrase "permanently ceased generating," because plants can exist in various stages of generation, including seasonal mothball status, depending on the market conditions and the needs of the independent system operators. EPA disagrees that this is necessary or appropriate, as any facility that generates power after October 19, 2015, is considered an "active facility," that is covered under the existing regulations. See, 40 CFR 257.53 (defining Active facility). Under § 257.50(c), the regulations apply to "inactive CCR surface impoundments at active electric utilities or independent power producers, regardless of the fuel currently used at the facility to produce electricity." 40 CFR 257.50(c).

The question has been raised whether the phrase "regardless of the fuel currently used to produce electricity" in § 257.50(c) indicates that EPA meant to limit the rule to facilities that combust fossil fuels; but the provision does not state or even imply that limitation. The definition of an active facility does not include any limitation related to how the facility generates electricity, including fuel use. Nor does the clause, "regardless of the fuel currently used to produce electricity" in § 257.50(c) add a fuel use limitation into that definition, or otherwise create a fuel use limitation in the scope of the rule. The plain language of the clause states the opposite; that coverage applies without regard to the fuel used to produce electricity. Or in other words, without regard to the type of fuel used or indeed whether any fuel is used to produce electricity. Nevertheless, to avoid any further confusion, EPA is proposing to amend the provision to specify that the subpart also applies to inactive CCR surface impoundments at active electric utilities or independent power producers, regardless of how electricity is currently being produced at the facility.

Finally, EPA requested comment as to whether the Agency's regulation of inactive CCR surface impoundments should be limited to only units at former power plants that sold electric power to the grid or whether it should also reach

units at former power plants that provided power to a single site or facility. In response, some commenters said that EPA should regulate all inactive impoundments without regard to whether those impoundments are located at power plants that once sold electric power to the grid or supplied it only to a single site or facility. They said it is not the location of the impoundment, but rather the presence of coal ash, that controls. Other commenters said this could also prove to be a thorny factual issue, as, in many cases, the same power plant might have served a single site or facility for some period of time as well as served the grid at other times.

For the same reasons that EPA did not include CCR generated by non-utility boilers in the 2015 CCR Rule, EPA is not proposing to regulate units at former power plants that provided power to a single site or facility. See, 80 FR 21340. EPA lacks critical data about such facilities needed to determine whether and how to regulate such facilities. These facilities are primarily engaged in business activities, such as agriculture, mining, manufacturing, transportation, and education. These industries, and the manufacturing industries in particular, generate other types of wastes that are often mixed or co-managed with the CCR at least at some facilities. As a result, the chemical composition of the co-managed waste is likely to be fundamentally different from the chemical composition of CCR generated by electric utilities or independent power producers. EPA requests comment on the likely chemical composition of other types of wastes generated by these industries that were co-managed with any CCR generated at such facilities. Insufficient information is also available on such facilities to determine whether a regulatory flexibility analysis will be required under the Regulatory Flexibility Act, and to conduct one if it is necessary. EPA therefore requests comment on whether the Agency should continue to pursue this issue by seeking to obtain the information necessary to determine whether regulation of such facilities is warranted.

d. Conclusions Related to Scope of Coverage

After considering all of this information, EPA is proposing to define a legacy CCR surface impoundment as: A surface impoundment that is located at a power plant that ceased generating power prior to October 19, 2015, and the surface impoundment contained both CCR and liquids on or after October 19, 2015. EPA considers this definition to

be the most protective of human health and the environment for the reasons provided herein.

Alternatively, EPA solicits comments on defining a "legacy CCR surface impoundment" as: A CCR surface impoundment at a power plant that ceased generating power prior to October 19, 2015, and the surface impoundment contains both CCR and liquids on or after the effective date of the legacy CCR surface impoundment final rule.

2. Applicable Requirements for Legacy CCR Surface Impoundments and Compliance Deadlines

This Unit of the preamble first provides a general overview of how EPA determined the applicable requirements and compliance deadlines for legacy CCR surface impoundments. Then, EPA will walk through each of the existing requirements for CCR surface impoundments and explain (1) Why EPA is proposing to apply them (or not) to legacy CCR surface impoundments, and (2) The rationale for the compliance deadline EPA is proposing for each requirement.

a. General Overview

i. Applicable Requirements

Based on the record compiled for the 2015 CCR Rule, EPA concluded that "there is little difference between the potential risks of an active and inactive surface impoundment; both can leak into groundwater, and both are subject to structural failures that release the wastes into the environment, including catastrophic failures leading to massive releases that threaten both human health and the environment." (80 FR 21343). As discussed in Unit III.B of this preamble, the D.C. Circuit concurred, and on that basis, vacated the exemption for legacy CCR surface impoundments. See, *USWAG* at 901 F.3d at 434. EPA received no information in response to the ANPRM that would support a conclusion that legacy CCR surface impoundments present fewer risks than other inactive CCR impoundments. Based on this record and on the specificity of the D.C. Circuit's findings in *USWAG*, EPA considers that it has limited discretion to establish requirements for legacy CCR surface impoundments that are significantly different than those currently applicable to inactive CCR impoundments. Accordingly, EPA is proposing that, in most cases the existing requirements in 40 CFR part 257, subpart D applicable to inactive CCR surface impoundments would apply to legacy CCR surface

impoundments. EPA is proposing to make one revision to the existing groundwater monitoring requirements. In addition, EPA is proposing to establish two new requirements specific to legacy CCR surface impoundments: a reporting requirement and a new security requirement to restrict public access to these sites. Finally, EPA is proposing that legacy CCR surface impoundments would not be subject to either the location restrictions at §§ 257.60 through 257.64, or the liner design criteria at § 257.71. EPA is proposing to exclude these requirements because EPA believes they will not be necessary if EPA takes final action on the proposed requirement that all legacy CCR surface impoundments initiate closure no later than 12 months after the effective date of the final rule.

Some commenters on the ANPRM said that all provisions currently required for CCR surface impoundments at active power plants (or those that were operating as of the effective date of the rule), are just as necessary—if not more so—at legacy CCR surface impoundments to ensure satisfaction of the RCRA section 4004(a) protectiveness standard. Other commenters said the only applicable requirements should be groundwater monitoring, closure, post-closure care, and related recordkeeping requirements. Several of these commenters also said that the 2015 CCR rulemaking record is not directly applicable to the universe of units that are located at inactive power plants and still contain CCR and liquids. They said the 2014 CCR Risk Assessment used to develop the 2015 CCR Rule was limited to current disposal practices and did not consider units that had stopped receiving waste or historically disposed of CCR by facilities that no longer operate. According to these commenters, the Agency must first accurately identify the universe of legacy CCR surface impoundments, the

specific characteristics of risk for those impoundments, and then analyze whether other authorities are sufficient to address any risk from these legacy CCR surface impoundments.

Finally, some commenters requested that EPA include a mechanism for legacy CCR surface impoundment owner(s) and/or operator(s) to demonstrate that, in such cases, additional CCR requirements would be unnecessary. The commenters stated that this would be similar to the case-by-case determinations established under the Holistic Approach to Closure Parts A and B final rules (85 FR 53516 and 85 FR 72506) that provided a mechanism for the Agency to issue variances for plants that could successfully make the required demonstration.

ii. Compliance Deadlines

EPA is proposing to establish new compliance dates for legacy CCR surface impoundments. The compliance deadlines in the 2015 CCR Rule were generally based on the amount of time determined to be necessary to implement the requirements. To determine what was feasible, EPA accounted for the fact that some of the new requirements involved numerous activities, many of which must occur sequentially (e.g., the groundwater monitoring requirements in §§ 257.90 through 257.95), as well as concerns about shortages of contractor and lab resources resulting from the fact that those numerous facilities would need to come into compliance at the same time. EPA also accounted for other Agency rulemakings that could have affected the owners or operators of CCR units, namely the 2015 Effluent Limitation Guidelines (ELG) and Standards for the Steam Electric Power Generating Point Source Category and the Carbon Pollution Commission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. In establishing

the proposed deadlines for legacy CCR surface impoundments, EPA adopted the same approach, and is proposing deadlines based on the amount of time determined to be necessary to implement the requirements. But some of the factors considered in the 2015 rulemaking are not relevant for legacy CCR surface impoundments; for example, there is no longer a need to coordinate with the ELG compliance deadlines. In addition, most facilities are already familiar with these requirements as they have already implemented them for other units at their active sites, so the timeframes need not account for the time that would be needed for a facility to understand the regulations and develop strategies for compliance. Finally, there will be fewer facilities and units that will need to come into compliance, and EPA no longer has concerns about shortages of contractors and lab resources. Consequently, EPA is generally proposing expedited timeframes for legacy CCR surface impoundments to comply with the regulations, based on the shortest average amount of time needed to complete the activities involved in meeting the requirements. Overall, comments submitted in response to the ANPRM acknowledged these differences and most supported the establishment of shorter deadlines than were established in the 2015 CCR Rule.

Note that all deadlines herein are framed by reference to the effective date of the rule and have been proposed based on an effective date that is six months from publication of the final rule. The Agency has included a document in the docket¹³ for this rule that summarizes the proposed compliance deadlines. EPA requests comment on the compliance deadlines and the feasibility to meet the proposed compliance timeframes for legacy CCR surface impoundments.

TABLE 1—PROPOSED COMPLIANCE TIMEFRAMES FOR LEGACY CCR SURFACE IMPOUNDMENTS IN MONTHS AFTER EFFECTIVE DATE OF THE FINAL RULE

40 CFR part 257, subpart D requirement	Description of requirement to be completed	Proposed deadline (months after effective date of the final rule)	Notes
Applicability Documentation (§ 257.100).	Applicability Documentation for the legacy CCR surface impoundment.	0	Prerequisite requirements: Establish CCR website. Subsequent requirements: History of construction; Initial structural stability assessment; Initial safety factor assessment.
Design Criteria (§ 257.73) Site Security (§ 257.100(f)(3)(iii))	Install permanent marker Implement site security measures.	0. 0.	

¹³ This information can be found in the document titled “Proposed Compliance Deadlines for Legacy

CCR Surface Impoundments and CCR Management Units” in the docket for this action.

TABLE 1—PROPOSED COMPLIANCE TIMEFRAMES FOR LEGACY CCR SURFACE IMPOUNDMENTS IN MONTHS AFTER EFFECTIVE DATE OF THE FINAL RULE—Continued

40 CFR part 257, subpart D requirement	Description of requirement to be completed	Proposed deadline (months after effective date of the final rule)	Notes
Operating Criteria (§ 257.80)	Prepare fugitive dust control plan.	0	Subsequent requirements: Initial annual fugitive dust report.
Operating Criteria (§ 257.80, 257.82, 257.83).	Initiate weekly inspections of the CCR unit.	0	Subsequent requirements: Initial annual inspection of the CCR unit.
Operating Criteria (§ 257.80, 257.82, 257.83).	Initiate monthly monitoring of CCR unit instrumentation.	0	Subsequent requirements: Initial annual inspection of the CCR unit.
Internet Posting (§ 257.107)	Establish CCR website	0	Subsequent requirements: Applicability report; all recordkeeping.
Design Criteria (§ 257.73)	Compile a history of construction	3	Prerequisite requirements: Applicability report. Subsequent requirements: Hazard potential classification; Emergency Action Plan; Initial hazard classification assessment; Initial structural stability assessment; Initial safety factor assessment; Initial annual inspection; Groundwater monitoring system.
Design Criteria (§ 257.73)	Complete initial hazard potential classification assessment.	3	Prerequisite requirements: Applicability report; History of construction. Subsequent requirements: Emergency Action Plan.
Design Criteria (§ 257.73)	Complete initial structural stability assessment.	3	Prerequisite requirements: Applicability report; History of construction. Subsequent requirements: Emergency Action Plan.
Design Criteria (§ 257.73)	Complete initial safety factor assessment.	3	Prerequisite requirements: Applicability report; History of construction. Subsequent requirements: Emergency Action Plan.
Operating Criteria (§ 257.80, 257.82, 257.83).	Complete the initial annual inspection of the CCR unit.	3	Prerequisite requirements: History of construction; Weekly inspections of the CCR unit; Monthly monitoring of CCR unit instrumentation.
GWMCA (§ 257.91)	Install the groundwater monitoring system.	6	Prerequisite requirements: Applicability report; History of construction. Subsequent requirements: Groundwater sampling and analysis program; Initiate detection and assessment monitoring; Annual GWMCA report; Written closure plan; Initiate closure.
GWMCA (§ 257.93)	Develop the groundwater sampling and analysis program.	6	Prerequisite requirements: Install the groundwater monitoring system. Subsequent requirements: Initiate detection monitoring and assessment monitoring.
GWMCA (§ 257.90(e))	Annual GWMCA report	January 31 of the year following GWM system install.	Prerequisite requirements: Groundwater monitoring system; Groundwater sampling and analysis plan.
Design Criteria (§ 257.73)	Prepare Emergency Action Plan	9	Prerequisite requirements: History of construction; Hazard potential classification; Initial structural stability assessment; Initial safety factor assessment.
Operating Criteria (§ 257.82)	Prepare initial inflow design flood control system plan.	9	Prerequisite requirements: History of construction; Hazard potential classification.
Operating Criteria (§ 257.80)	Prepare initial annual fugitive dust report.	12	Prerequisite requirements: Fugitive dust plan.
Closure (§§ 257.100–257.101) ...	Prepare written closure plan	12	Subsequent requirements: Initiate closure.
Post-Closure Care (§ 257.104) ...	Prepare written post-closure care plan.	12	Prerequisite requirements: Written closure plan.
Closure and Post-Closure Care (§ 257.101).	Initiate closure	12	Prerequisite requirements: Written closure plan.
GWMCA (§§ 257.90–257.95)	Initiate the detection monitoring and assessment monitoring. Begin evaluating the groundwater monitoring data for SSI over background levels and SSL over GWPS.	24	Prerequisite requirements: Groundwater monitoring system; Groundwater sampling and analysis plan.

b. New Requirements Specific to Legacy CCR Surface Impoundments

i. Legacy CCR Surface Impoundment Applicability Documentation

EPA is proposing to require the owner and operator of a legacy CCR surface impoundment to prepare an applicability documentation for any legacy CCR surface impoundment at that facility no later than the effective date of the final rule. This requirement would apply to all legacy CCR surface impoundments, including incised impoundments and impoundments that do not meet the height and storage volume cutoffs specified in § 257.73(b). See, proposed regulatory text at § 257.100(f)(1)(i). EPA is proposing that this applicability documentation would include information to identify the unit, delineate the unit boundaries, include a figure of the facility and where the unit is located at the facility, the size of the unit, its proximity to surface water bodies, and the current site conditions. For impoundments that are incised or for those not meeting the height and storage volume thresholds specified in § 257.73(b), the applicability report must document these conditions so that stakeholders can understand what structural integrity requirements will apply to the legacy CCR surface impoundment. EPA is also proposing that the applicability report include the facility address, latitude and longitude, and contact information of the owner and/or operator of the legacy CCR surface impoundment with their phone number and email address. EPA is also proposing that the owner or operator of the legacy CCR surface impoundment notify the Agency of the establishment of the facility's CCR website and the applicability of the rule, using the procedures currently in § 257.107(a) via the "contact us" form on EPA's CCR website.

ii. Site Security for Legacy CCR Surface Impoundments

Active facilities generally have guards and fencing to control access to the facility, but inactive CCR facilities may not have such security controls in place at the facility. To minimize that risk, EPA is proposing that owners and operators establish security controls to restrict access to legacy CCR surface impoundments. The proposed security requirements are written in terms of a performance standard, as opposed to a prescriptive set of technical standards, such as specific signage, barriers and fencing, or surveillance techniques. EPA chose this approach because it would allow the owner or operator to identify the most appropriate means for

providing site security for the impoundment based on site-specific circumstances.

Some commenters on the ANPRM agreed that such requirements are necessary because legacy CCR impoundments are located at inactive power plants, unlike impoundments at operating power plants, they almost certainly lack the oversight and protection afforded by significant numbers of on-site personnel. Consequently, the integrity of impoundments and berms and the safety of nearby residents depend on robust security measures to ensure that people are not—whether intentionally or unknowingly—entering the site and taking actions (such as ATV driving, dirt biking, or similar activities) that endanger the integrity of the impoundment or expose trespassers to health risks.

The proposed site security performance standard would require the owner or operator to prevent the unknowing entry of people onto the legacy CCR surface impoundment and to minimize the potential for the unauthorized entry of people or livestock onto the impoundment. See proposed regulatory text in § 257.100(f)(3)(iii). The Agency generally modeled the proposed requirements on existing regulations that apply to interim status hazardous waste surface impoundments, which are codified at § 265.14(a). EPA recognizes that some facilities may have facility-wide access controls in place, and in this case, the facility-wide controls would satisfy the proposed requirement to limit public access to the legacy CCR surface impoundment. The Agency is proposing to require the facility to restrict access to the area containing the legacy CCR surface impoundment no later than the effective date of the final rule. See, proposed regulatory text at § 257.100(f)(3)(iii).

iii. Certification of Closure by Removal for Legacy CCR Surface Impoundments

As discussed in Unit IV.A.1.b.ii of this preamble, where a legacy CCR surface impoundment has completed closure of the CCR unit by removal of waste in accordance with the performance standards in § 257.102(c) prior to the effective date of the final rule, EPA is proposing that the owner and operator of an inactive facility post documentation that they have met the existing standard for closure by removal in § 257.102(c) on their CCR website. If such a demonstration cannot be made, the CCR surface impoundment would be regulated as a legacy CCR surface impoundment. EPA is proposing to

require that the closure certification be certified by a qualified professional engineer (P.E.). EPA is proposing to require certification by a qualified professional engineer even though the Agency now has authority to enforce the part 257 regulations. This is because the certification is not intended as a substitute for EPA's oversight, but as a supplement to ensure that the regulated community properly understands and implements the regulations. As EPA explained in 2015, the purpose of requiring certification was to ensure that qualified individuals verify that the technical provisions of the rule have been properly applied and met, not to delegate regulatory oversight to the engineer, or to serve as a shield against judicial enforcement. See 80 FR 21335. Consistent with the original 2015 requirements, the performance standards that EPA is proposing to establish are independent requirements and would remain enforceable regardless of whether a P.E. certification has been obtained.

EPA is proposing to require that the certified demonstration be completed and posted on the facility website no later than the effective date of the final rule. See proposed regulatory text at § 257.100(f)(1)(ii). Because the closure of the unit will have been already completed, the information on which to base the demonstration should be readily available. Consequently, EPA believes that requiring completion of this requirement, if applicable, by the effective date of the final rule provides sufficient time for such a task.

c. Location Restrictions and Liner Design Criteria

The CCR regulations require existing CCR surface impoundments that cannot demonstrate compliance with the location restrictions for placement of CCR above the uppermost aquifer, in wetlands, within fault areas, in seismic impact zones, or in unstable areas (specified in §§ 257.60 through 257.64) to cease receipt of waste and retrofit or close. The purpose of these requirements is largely to ensure that units located in particularly problematic areas cease operation. By definition, legacy CCR surface impoundments are not operating, and because it appears that all legacy CCR surface impoundments are unlined and will therefore be required to close, EPA believes that requiring compliance with the location restrictions would be largely redundant. Commenters on the ANPRM largely supported not requiring location restrictions or liner demonstrations on the grounds that location restrictions and operating and

design criteria are not relevant to this class of units, as these requirements primarily sought to ensure active units operated safely. Other commenters raised concern that requiring compliance with one or more location restrictions would provide information that would be “critical” to designing unit closure and any necessary corrective action. EPA agrees that this information would be useful but believes the same information will be captured by compliance with the history of construction requirement, the closure plan, or in the development of the groundwater monitoring system.

EPA is also proposing that the requirement to document whether the impoundment was constructed with a composite liner or alternative composite liner under § 257.71(a)(1) is not warranted for legacy CCR surface impoundments. The original purpose of this provision was to determine whether the unit was unlined, and consequently subject to closure. However, the available information indicates that legacy CCR surface impoundments were largely constructed well before composite liners systems were typically installed. For this reason, EPA expects legacy CCR surface impoundment to be unlined and, therefore, EPA is proposing to require all legacy CCR surface impoundments to close. As a consequence, EPA believes that requiring facilities to compile the information required by § 257.71(a)(1) would not provide useful information or otherwise be necessary.

d. Design Criteria for Structural Integrity for Legacy CCR Surface Impoundments

To help prevent damages associated with structural failures of CCR surface impoundments, existing surface impoundments must meet specified structural integrity criteria in § 257.73 as part of the design criteria. EPA is proposing that all existing structural integrity requirements be applicable to legacy CCR surface impoundments without revision.

i. Installation of a Permanent Marker for Legacy CCR Surface Impoundments

Consistent with the existing requirements for CCR surface impoundments, EPA is proposing that owners or operators of legacy CCR surface impoundments, except for “incised CCR surface impoundments” as defined in § 257.53, comply with § 257.73(a)(1), which requires the placement of a permanent identification marker, at least six feet high on or immediately adjacent to the CCR unit with the name associated with the CCR unit and the name of the owner or

operator. See, proposed regulatory text at § 257.100(f)(2)(i).

EPA is proposing that placement of the permanent marker must be completed by the owner or operator of the legacy CCR surface impoundment by the effective date of the final rule. By comparison, installation of a permanent marker was required two months after the effective date of the 2015 CCR Rule. The proposed deadline is expedited for the reasons described in Unit IV.A.2.a.ii of this preamble and accounts for sufficient time for survey work, and review of records in facility deeds or other records.

ii. History of Construction for the Legacy CCR Surface Impoundments

Under the existing regulations, CCR surface impoundments that either have: (1) A height of five feet or more and a storage volume of 20 acre-feet or more; or (2) Have a height of 20 feet or more, must document the design and construction of the CCR surface impoundment. 40 CFR 257.73(b) and (c). See also 80 FR 21379–21380, April 17, 2015. EPA is proposing that owners or operators of legacy CCR surface impoundments that meet this size threshold would be required to comply with the existing requirements to compile the construction history of the legacy CCR surface impoundment. See proposed regulatory text in § 257.100(f)(2)(ii).

Some commenters on the ANPRM agreed that the history of construction is critical to an evaluation of the long-term stability of legacy CCR surface impoundments, which must be considered to determine if the closure performance standards for closure in place can be met at the impoundment and whether a given corrective action meets the requirement to select a safe, protective remedy. The history of construction is also critical in the event of any failure of the impoundment: emergency response personnel must have access to that information to determine how to halt further failure, and further release of CCR, as quickly as possible.

For legacy CCR surface impoundments, EPA acknowledges that much of the construction history of the surface impoundment may be unknown or lost to time. The Agency conducted assessments of impoundments across the country starting in 2009 (herein referred to as 2009–2014 Assessment Program). For information about these assessments and how the results impacted the 2015 CCR Rule, see 80 FR 21313–21318 (April 17, 2015). The results from the 2009–2014 Assessment Program confirmed that many owners or

operators of CCR units did not possess documentation on the construction history or operation of the CCR unit. 80 FR 21380. Information regarding construction materials, expansions or contractions of units, operational history, and history of events was frequently difficult for the owners or operators to obtain. Therefore, consistent with the existing regulations, the owner or operator would only need to provide information on the history of construction to the extent that such information is reasonably and readily available.

To complete the history of construction report, typically, the owner and operator first enlist a contractor to generate the history of construction report. Contracting typically involves the owner and operator issuing a request for proposal, contractors responding to the request, and the owner and operator evaluating the bids and selecting a contractor (estimate 1–2 weeks). Following selection and onboarding of a contractor, a data inventory, compilation, and review of existing documents is completed by the owner and operator and contractor to meet the requirements in § 257.73(c)(1)(i) through (xi) (estimate 4–6 weeks). Examples of documents compiled may include the CCR unit’s design drawings and construction documents, such as construction reports, quality assurance, as-built records, and historic boring log reviews (e.g., subsurface investigation used for original CCR unit design, post-construction subsurface investigations, geotechnical studies). Data from external sources may also be needed such as the U.S. Geological Survey (USGS) 7.5-minute or 15-minute topographic quadrangle maps (§ 257.73(c)(1)(ii)) or National Hydrography Datasets (§ 257.73(c)(1)(iv)). The compiled data must then be reviewed, analyzed, and documented in reports (estimate 3–4 weeks). Examples of analyses may include maximum CCR depths, area-capacity curves, spillway capacities, and the maximum pool surface elevation following peak discharge from the inflow design flood. This estimate assumes that no new extensive analyses are needed, and that all necessary information can be derived from existing reports (e.g., hydraulic and hydrologic reports). If new analyses are needed (e.g., maximum CCR depth), they are assumed to be minor with data inputs for performing these analyses existing and readily available such as field surveys (e.g., historic site preparation surveys, post-construction/as-built surveys, periodic surveys,

bathymetric surveys). Based on these assumptions, the time required to generate a history of construction report is 8–12 weeks or 2–3 months. Therefore, EPA is proposing to require the history of construction report to be compiled no later than 3 months after the effective date of the final rule.

Expediting this timeframe compared to the 2015 CCR Rule timeframe is important for the reasons described above in Unit IV.A.2.a.ii of this preamble and because several additional requirements depend on the information that would be obtained by compliance with these requirements. For example, available geologic subsurface information from history of construction is typically necessary to determine the number, spacing and location of monitoring wells for the installation of a groundwater monitoring system that meets the criteria of § 257.91. Another example is that § 257.73(c)(1)(xi) requires reporting any record or knowledge of structural instability of the CCR unit; this information is also needed for the initial and periodic structural stability assessments required under § 257.73(d).

iii. Initial Hazard Potential Classification for Legacy CCR Surface Impoundments

Consistent with the existing regulations, EPA is proposing that owners or operators of legacy CCR surface impoundments, except for incised CCR surface impoundments as defined in § 257.53, must complete the initial periodic hazard potential classification assessment required under § 257.73(a)(2). See, proposed regulatory text at § 257.100(f)(2)(iii).

Hazard potential classification assessments require activities that can be summarized as data/documentation review, a site visit, and report generation. As stated above, acquiring a contractor may take 1–2 weeks. The contractor would then perform a site visit and review available hazard documents such as existing state or federal dam hazard potential classification documents or any previous structural stability or safety factor documentation. The contractor then generates a P.E.-certified report stating the hazard classification determination and basis for the findings. The site visit is estimated to take 1 week. The data/documentation review and report generation are expected to take a total of 4–6 weeks. Based on these estimates, the total time needed to conduct the initial hazard potential classification assessment is 6–9 weeks. Accordingly, EPA is proposing the initial hazard potential classification

assessment be due no later than 3 months after the effective date of the final rule. The proposed deadline provides sufficient time to complete the activities necessary to satisfy this requirement, while allowing time (3–6 six weeks) for reasonable delays, such as weather delaying a site visit or difficulty obtaining pertinent documentation. This timeframe is expedited from the deadline in the 2015 CCR Rule by 9 months for the reasons described above in Unit IV.A.2.a.ii of this preamble.

iv. Initial Structural Stability Assessment and Initial Safety Factor Assessment for Legacy CCR Surface Impoundments

Under the existing regulations, CCR surface impoundments that meet the size thresholds in § 257.73(b) and (c), must conduct two different types of technical assessments: (1) A structural stability assessment; and (2) A safety factor assessment. See 40 CFR 257.73(b), (d), (e), and (f). See also 80 FR 21380–21386, April 17, 2015. EPA is proposing that owners or operators of legacy CCR surface impoundments that meet the same thresholds also comply with the requirements to conduct an initial structural stability assessment and an initial safety factor assessment. See, proposed regulatory text at § 257.100(f)(2)(iv).

Some commenters on the ANPRM said structural stability assessments and safety factor assessments must apply to legacy CCR surface impoundments since the risks from such units are likely greater at legacy CCR surface impoundments, given the age of such units; the higher percentage of legacy ponds (as compared to operating ash ponds) that were neither designed by, nor built under the supervision of, a P.E.; and the higher percentage of legacy CCR surface impoundments determined to be in “poor” or “fair” condition.

The Agency conducted assessments of impoundments across the country starting in 2009 in the 2009–2014 Assessment Program. For information about these assessments and how the results impacted the 2015 CCR Rule, see 80 FR 21313–21318 (April 17, 2015). EPA analyzed the results of the 2009–2014 Assessment Program and found that 97 impoundments¹⁴ assessed during the Program are located at inactive CCR facilities. Of those impoundments, EPA found that six impoundments are classified as high hazard potential, and 41 impoundments are classified as significant hazard

potential meaning that failure or misoperation of the dam will probably cause loss of human life or can cause economic or environmental losses. This further supports EPA’s conclusion that these requirements are needed for legacy CCR surface impoundments.

Activities required to conduct the initial structural stability assessment include reviewing historic documents, conducting a site investigation (if needed), and generating a P.E.-certified report. Typically, owners or operators hire a contractor who is a certified P.E., which, as detailed above, may take one to two weeks. The contractor would then compile and review historic documents to determine if the design, construction, operation, and maintenance of the CCR unit are consistent with good engineering practices, which may take 2–3 weeks. These documents likely overlap with those already compiled for the history of construction and may include the design drawings, construction reports, quality assurance documentation, as-built records, subsurface investigations, geotechnical studies, and site inspections. Stability of the CCR unit’s embankment and foundation may be demonstrated through slope stability analyses. Because slope stability analyses are typically required to satisfy safety factor assessments, no additional time is considered necessary to satisfy the requirements under § 257.73(d). Although site inspections would likely already have occurred by the effective date of the final rule pursuant to § 257.83(a) or § 257.83(b), it may be necessary for the qualified P.E. to perform a site inspection to certify the CCR unit meets the requirements as set forth in § 257.73(d). Therefore, 1 week for the site inspection is factored into the estimated time to complete these assessments. Finally, generating a P.E.-certified report may take 4–6 weeks. The total estimated time to meet this requirement is 8–12 weeks.

Activities required to complete the initial safety factor assessment may include hiring a contractor that is a qualified P.E., which may take 1–2 weeks and conducting slope stability analyses of critical cross sections, as defined in § 257.73(e)(1). For the initial assessment, it is anticipated that no new field work will be required to gather this data and that the input parameters required for the analysis (e.g., soil geotechnical properties, seasonal high-water table) are available in historic documents such as the subsurface investigation used for the original CCR unit design, post-construction subsurface investigations, and/or geotechnical studies. Compilation and

¹⁴ This information can be found in the document titled “Potential Legacy CCR Surface Impoundment Universe” in the docket for this action.

review of this data is estimated to take 2–3 weeks, followed by 5–7 weeks for data analysis and reporting. The total estimated time needed to meet requirements for completion of the safety factor assessment is 8–12 weeks.

The activities for the initial structural stability and initial safety factor assessments can be conducted concurrently and based on the estimates above, should take a total of 8–12 weeks (2–3 months). Therefore, as stated above, EPA is proposing both the initial structural stability assessment and the initial safety factors assessments be completed no later than 3 months after the effective date of the final rule. These timeframes are expedited by 15 months from the 2015 CCR Rule deadline. EPA believes the expedited timeframe is important to address the risks posed by legacy CCR surface impoundments, as described in this Unit and in Unit IV.A.2.a.ii of this preamble.

v. Preparation of an Emergency Action Plan for Legacy CCR Surface Impoundments

Section 257.73(a)(3) requires any CCR surface impoundment that is determined by the owner or operator, with the certification by a P.E., to be either a high hazard potential or a significant hazard potential CCR surface impoundment to prepare and maintain a written Emergency Action Plan (EAP). EPA is proposing that the owners or operators of legacy CCR surface impoundments that have been identified as having either a high hazard potential or a significant hazard potential would be required to comply with the same requirements to prepare and maintain an EAP that are currently required under § 257.73. See proposed regulatory text at § 257.100(f)(2)(v).

An EAP is a document that identifies potential emergency conditions at a CCR surface impoundment and specifies actions to be followed to minimize loss of life and property damage. To prepare an EAP, the owner or operator must accurately and comprehensively identify potential failure modes and at-risk developments. See also 80 FR 21377–21379, April 17, 2015. Satisfying EAP requirements is primarily a desktop exercise that requires information on site conditions, some analyses, and assessments that are proposed to be completed earlier. Typically, the owner and operator enlist a contractor to generate the EAP, which, as described above may take 1–2 weeks. Once onboard, it is assumed that the contractor would review site-specific documents, assessments, and analyses that were completed earlier and that may have an impact on development of

an EAP. These documents and assessments may include the history of construction, initial structural stability assessment, initial safety factor assessment, initial hazard potential classification, hydraulic and hydrologic analyses for inundation maps and potential impact areas, and the first annual inspection. Assuming all analyses discussed in the preceding sections are completed by the proposed deadlines of 3 months after the effective date of the final rule, the review of existing documents and assessments is estimated to take 4–6 weeks. Additional analyses, such as dam breach analyses or inundation evaluations, may be needed to define events or circumstances that may represent a safety emergency. If needed, these analyses may take 3–6 weeks). The contractor would then prepare the EAP including describing procedures to follow in an emergency, gathering emergency responder contact information and defining responsible persons, assigning responsibilities, and detailing notification procedures. This may take 6–8 weeks because the required coordination with community or government entities. Based on these assumptions, the time required to complete an EAP is 3–6 months. Therefore, EPA is proposing a deadline of 9 months after the effective date for this requirement. This timeline is sufficient to review previously prepared documents, complete additional analyses and prepare the EAP while accounting for the 3 months allotted for the prerequisite assessments.

e. Operating Criteria for Legacy CCR Surface Impoundments

The operating criteria in §§ 257.80, 257.82, and 257.84 include air criteria for all CCR units, hydrologic and hydraulic capacity requirements for CCR surface impoundments, and periodic inspection requirements for CCR surface impoundments. These criteria address the potential risks from the day-to-day operations of CCR units and are established to prevent health and environmental impacts from CCR units. CCR surface impoundments are subject to hydrologic and hydraulic capacity requirements to ensure the unit can safely handle flood flows, which will help prevent uncontrolled overtopping of the unit or erosion of the materials used to construct the surface impoundment. The CCR regulations also require periodic inspections of CCR units to identify any appearance of structural weakness or other conditions that are not consistent with recognized and generally accepted good engineering standards. EPA is proposing

that legacy CCR surface impoundments comply with these existing requirements without revision.

i. Fugitive Dust Control Plan for Legacy CCR Surface Impoundments

EPA is proposing that owners or operators of legacy CCR surface impoundments must complete a fugitive dust control plan. See, proposed regulatory text at § 257.100(f)(3)(i). The existing regulations require the owner or operator of a CCR unit to adopt measures that will effectively minimize CCR from becoming airborne at the facility, including CCR fugitive dust originating from CCR units, roads, and other CCR management and material handling activities. 40 CFR 257.80(b). To meet this requirement, the owner or operator of the CCR unit must prepare and operate in accordance with a fugitive dust control plan. *Id.* See also 80 FR 21386–21388, April 17, 2015. EPA considers that fugitive dust controls are warranted because closure activities can produce significant quantities of dust. For the same reason, most commenters on the ANPRM agreed that legacy CCR surface impoundments should be subject to these requirements.

The primary activities associated with this requirement are hiring a contractor who is a qualified P.E., having the contractor develop a plan based on daily operations at the unit and site conditions, and certification of the plan by a P.E. Little to no field-based activities are required to complete the fugitive dust control plan, so EPA is proposing that the owner or operator comply with the existing requirements by the effective date of the final rule. This timeline is commensurate with the timeline proposed in the 2015 CCR Rule for fugitive dust control plans.

ii. Initial Fugitive Dust Control Report for Legacy CCR Surface Impoundments

EPA is proposing to require the initial annual fugitive dust report to be due 12 months after the effective date of the final rule. See, proposed regulatory text at § 257.100(f)(3)(vi). Consistent with the existing regulations, the report must document all actions taken to control CCR fugitive dust, a record of all citizen complaints, and a summary of any corrective measures taken in the previous year. As this report is primarily a summary of owner or operator activities related to fugitive dust control and does not require a P.E. certification, the report may be completed by the owner or operator without the need for a contractor. Therefore, the deadline of 12 months after effective date of rule is sufficient for this requirement. This deadline is

expedited by 2 months from the 2015 CCR Rule deadline for the reasons described above in Unit IV.A.2.a.ii of this preamble. Because EPA is proposing that the fugitive dust control plan would be due on the effective date of the final rule, this would mean that the first annual report would be due one year after the plan is developed. The owner or operator has completed the annual CCR fugitive dust control report when the plan has been placed in the facility's operating record.

iii. Weekly Inspections of the Legacy CCR Surface Impoundment and Monthly Monitoring of the CCR Unit's Instrumentation

EPA is proposing that owners and operators of legacy CCR surface impoundments must initiate the inspection requirements set forth in § 257.83(a) no later than the effective date of the final rule. See, proposed regulatory text at § 257.100(f)(3)(ii). Under § 257.83(a), all CCR surface impoundments must be examined by a qualified person at least once every seven days for any appearance of actual or potential structural weakness or other conditions that are disrupting or that have the potential to disrupt the operation or safety of the CCR unit. The results of the inspection by a qualified person must be recorded in the facility's operating record. Weekly inspections are intended to detect, as early as practicable, signs of distress in a CCR surface impoundment that may result in larger more severe conditions. Inspections are also designed to identify potential issues with hydraulic structures that may affect the structural safety of the unit and impact its hydraulic and hydrologic capacity. Section 257.83(a) also requires the monitoring of all instrumentation supporting the operation of the CCR unit to be conducted by a qualified person no less than once per month. See also 80 FR 21394–21395 (April 17, 2015).

EPA recognizes that field work may be necessary prior to initiating weekly inspections, such as hiring a contractor to perform vegetative clearing and establishing inspection routes. If necessary, these activities may take 2–4 weeks. EPA also acknowledges that instrumentation may already be installed as part of dam safety or other programs under state regulations. However, if instrumentation is not currently installed, 4–6 weeks may be needed for the installation of piezometers or other equipment. Based on these estimates, EPA's proposed deadline for the initiation of weekly inspections and monthly monitoring of

no later than the effective date of the final rule is sufficient for the completion of these activities. The proposed timeframe is the same as the 2015 CCR Rule deadline.

iv. Initial Annual Inspection for Legacy CCR Surface Impoundments

EPA is proposing that owners and operators of legacy CCR surface impoundments must conduct the initial annual inspection no later than 3 months after the effective date of the final rule. See, proposed regulatory text at § 257.100(f)(3)(iv). Existing CCR surface impoundments exceeding the height and storage volume thresholds in § 257.73(b) and (c), are required to conduct annual inspections of the CCR unit throughout its operating life (§ 257.83(b)). These inspections are focused primarily on the structural stability of the unit and must ensure that the operation and maintenance of the unit is in accordance with recognized and generally accepted good engineering standards. Each inspection must be conducted and certified by a P.E. See also 80 FR 21395, April 17, 2015.

Annual inspections include documentation review, a visual inspection of the CCR unit, and a visual inspection of any hydraulic structures underlying the base of the CCR unit or passing through the CCR unit's dike. Documentation reviewed as part of the annual inspection include operating records, previous structural stability assessments, and the results of previous weekly, monthly, and annual inspections and can overlap with reviews needed to complete the initial structural stability assessment.

EPA is proposing that owners and operators must prepare the initial inspection report for legacy CCR surface impoundments within the same timeframe—no later than 3 months from the effective date of the final rule—as was required for existing CCR surface impoundments in the 2015 CCR Rule. The Agency believes this timeframe to prepare the initial annual inspection is similarly appropriate for legacy CCR surface impoundments as for existing impoundments. As discussed in the preamble to the 2015 CCR Rule, the 3-month timeframe was based on EPA's experience with its CCR Assessment Program to evaluate the structural stability and safety of existing impoundments throughout the nation. Specifically, EPA found that 3 months would be adequate to complete the tasks supporting an annual inspection, including retaining the services of a P.E., reviewing relevant information in the facility's operating record,

conducting the field inspection, and completing the inspection report. See 80 FR 21395 (April 17, 2015).

v. Initial Inflow Design Flood Control System Plan for Legacy CCR Surface Impoundments

EPA is proposing that owners and operators of legacy CCR surface impoundments must prepare the inflow design flood control system plan 9 months after the effective date of the final rule. See, proposed regulatory text at § 257.100(f)(3)(v). Owners or operators of all CCR surface impoundments are required to design, construct, operate, and maintain hydraulic and hydrologic capacity to adequately manage flow both into and from a CCR surface impoundment during and after the peak discharge resulting from the inflow design flood, which is based on the Hazard Potential Classification of the CCR surface impoundment (§ 257.82(a)). The regulation also requires the preparation of an initial inflow design flood control system plan (§ 257.82(c)). See also 80 FR 21390–21392, April 17, 2015.

The primary activities associated with developing an inflow design flow control system can be summarized as document review, a site visit, hydrologic and hydraulic analyses (as needed), and report generation. Typically, owners and operators hire a P.E.-certified contractor, which, as described above, may take 1–2 weeks. The contractor would then perform a site visit (estimated to take one week) and review available pertinent documentation, such as topographical maps, aerial images, areal hydrological data, the unit's design drawings, the unit's construction reports, as-builts for the unit, previous area-capacity curves, and surface elevation data. EPA anticipates that many of these documents overlap with documents necessary for the history of construction report, hazard potential classification assessment, structural stability assessment, safety factor assessment, and annual inspection requirements, all of which are due no later than 3 months after the effective date of the final rule. Assuming all preceding analyses required by this rule are completed by their deadlines of 3 months after the effective date of the final rule, the review is estimated to take 4–6 weeks. Additional analyses, such as site-specific flood modeling and hydrologic and hydraulic (H/H) capacity calculations, may be needed to determine site-specific hydrological conditions or determine if the current H/H capacity is sufficient. These additional analyses are estimated to take

4–6 weeks. Finally, the contractor would generate the P.E.-certified inflow design flood control system plan documenting the design and construction of the flood control system, which may take another 4–6 weeks. Based on these estimates, the total time needed to prepare an initial inflow design control system plan is 14 to 21 weeks. Therefore, EPA is proposing a deadline of 9 months after the effective date of the final rule for this requirement. EPA believes this timeline is sufficient to develop the plan while accounting for the three months allotted for the prerequisite assessments. This is expedited from the deadline in the 2015 CCR Rule by three months for reasons described here in Unit IV.A.2.a.ii of this preamble.

f. Groundwater Monitoring and Corrective Action Criteria for Legacy CCR Surface Impoundments

The existing groundwater monitoring criteria in §§ 257.90 through 257.95 require an owner or operator of a CCR unit to install a system of monitoring wells and specify procedures for sampling these wells. Further, it sets forth methods for analyzing the groundwater data collected to detect hazardous constituents (e.g., toxic metals) and other monitoring parameters (e.g., pH, total dissolved solids) released from the units. 40 CFR 257.93. Once a groundwater monitoring system and groundwater monitoring program have been established for a CCR unit the owner or operator must conduct groundwater monitoring and, if the monitoring demonstrates an exceedance of the groundwater protection standards for identified constituents in Appendix IV of part 257, corrective action is required. These requirements apply throughout the active life and post-closure care period of the CCR unit.

There was widespread agreement among the commenters on the ANPRM that groundwater monitoring requirements would be appropriate for legacy CCR surface impoundments. However, some commenters argued that federal requirements would be duplicative and unnecessary. They suggested that EPA should allow facilities to demonstrate (through EPA review and approval) that the federal groundwater monitoring requirements are not necessary because existing groundwater monitoring systems established under state requirements meet the RCRA subtitle D protectiveness standard. These commenters said that overlapping federal and state groundwater monitoring and corrective action requirements would create

regulatory uncertainty, potentially interfering with site-specific plans designed to protect the environment and would ultimately delay work.

EPA is proposing to require legacy CCR surface impoundments to comply with the existing groundwater monitoring and corrective action requirements with one revision, described below, to require sampling and analysis of constituents listed in Appendix IV at the same time as those listed in Appendix III. The existing groundwater monitoring and corrective action requirements are essentially the same requirements that have been applied to both hazardous waste and municipal solid waste disposal units for decades, and with the one exception discussed below, there is nothing about legacy units that makes them distinct enough to warrant separate requirements. EPA disagrees that it would be appropriate as part of this rulemaking to allow facilities to demonstrate (through EPA review and approval) that existing groundwater monitoring systems established under different state requirements could substitute for federal requirements. As EPA has previously explained, in RCRA section 4005(d), Congress established specific standards and mandated the process for EPA to determine that state requirements should operate in lieu of the federal. Under those provisions, a State can apply to obtain authorization from EPA to operate its program (either in whole or in part) in lieu of the federal requirement by demonstrating that either of the standards in RCRA section 4005(d)(1)(B) has been met. Relying on that congressionally mandated process, rather than a separate process created in this rulemaking, is the appropriate route to address the commenters concerns about duplication between federal and state requirements.

i. Design and Installation of the Groundwater Monitoring System for Legacy CCR Surface Impoundments

EPA is proposing that owners and operators of legacy CCR surface impoundments install the groundwater monitoring system as required by § 257.91 no later than six months from the effective date of the final rule. See, proposed regulatory text at § 257.100(f)(4)(i). Existing monitoring wells can be used as a part of that system provided that they meet the federal criteria. Commenters on the ANPRM explained that in some states, the state may require the owner or operator to receive state approval before they can install a groundwater monitoring system. Therefore, the commenters said that one year is

inadequate to conduct these activities and two years is a more reasonable timeframe in which to carry out these activities. EPA disagrees that 12 months from the publication date (*i.e.*, 6 months from the effective date) would provide an insufficient amount of time to install groundwater monitoring wells. In the 2015 CCR Rule, EPA allotted 36 months total (from publication) for facilities to both install the wells and complete their baseline sampling. Based on the amount of time most facilities needed to complete or to collect baseline sampling, EPA calculates that facilities were able to install wells within a single year.

To complete the installation of the groundwater monitoring system, the first activity to meet § 257.91(f) may include hiring a contractor that is a qualified P.E. (estimate 1–2 weeks). The next activity may be to develop a workplan that determines the number, location, and depths of monitoring wells, which assumed to be developed based on available historic site characterization information including hydrogeologic setting, engineering design of the CCR unit or other information that may already be compiled in the history of construction requirement (§ 257.73(c)(1)) (estimate 7–9 weeks). Note that any additional site characterization is assumed to occur concurrently with the monitoring well installation. Subsequently, site reconnaissance may be performed along with vegetative clearing and utility locating, and the workplan may be modified to adjust for field conditions as needed (estimate 2 weeks when considering the installation of 10 monitoring wells). The next activity is to drill to depth, install and develop the 10 monitoring wells. The time to drill to depth can vary widely based on the drilling technique, subsurface lithology, site-specific conditions, weather, and other factors. It is estimated that a 100 foot well can be drilled to depth in 5 days at the rate of 20 feet/day. For 10 monitoring wells, the time to drill to depth is assumed to take 10 weeks. The monitoring wells must then be properly installed and constructed in accordance with § 257.91(e) and other requirements. Monitoring well development is assumed to take 3 days per well or 30 days for all 10 wells. The last activity is to develop documentation that records the design, installation, and development of the monitoring wells, subject to P.E. certification and submit monitoring well construction records to the appropriate state and federal agencies (estimate 4–6 weeks). Based on these assumptions, the total time

estimated for installation of a groundwater monitoring system is approximately 27–32 weeks, or 7–8.5 months. This deadline includes an additional 3.5-month buffer to adjust for delays in the field, installation of new additional wells, additional site characterization of newly discovered pertinent subsurface features (e.g., faults, karst features) or other modifications to the workplan based on site-specific information gained during the monitoring well installation. Thus, EPA is proposing to require the installation of the groundwater monitoring system no later than 6 months after the effective date of the final rule.

ii. Development of the Groundwater Sampling and Analysis Program for Legacy CCR Surface Impoundments

EPA is proposing to require owners and operators of legacy CCR surface impoundments to comply with the existing groundwater sampling and analysis program requirements for CCR surface impoundments, including the selection of the statistical procedures that will be used for evaluating groundwater monitoring data. 40 CFR 257.93. See, proposed regulatory text at § 257.100(f)(4)(ii).

Recommendations and information on how to comply with many of the requirements for the groundwater sampling and analysis program (e.g., analytical procedures, QA/QC controls, sampling protocol) can be found in the following EPA guidance documents (e.g., *RCRA Groundwater Monitoring: Draft Technical Guidance*, 1992, EPA/530/R-93/001; *Low-Flow (Minimal Drawdown) Ground-Water Sampling Procedures*, 1996, EPA/540/S-95/504). To develop the groundwater sampling and analysis program, the first steps would be to hire a contractor (1 to 2 weeks), review the groundwater monitoring system installation and other pertinent records (2 to 4 weeks), and develop the groundwater sampling and analysis program (4 to 6 weeks). Sometimes in complex hydrogeological settings (e.g., groundwater flow reversals surrounding CCR units adjacent to a large river), additional information from synoptic groundwater elevations may be necessary to refine the sampling program (e.g., establish upgradient/downgradient wells) (estimate 2 weeks). Based on these assumptions, the total time estimated to develop a groundwater sampling and analysis program is 9 to 14 weeks. The groundwater sampling and analysis program must include the list of monitoring wells to be sampled (e.g., sampling network). However, the list of

monitoring wells to be sampled can only be determined after installation of the groundwater monitoring system which is estimated to take 7 to 8.5 months. If it is assumed that the sampling and analysis program is developed (~2 to 3.5 months) only after the installation of the monitoring network (7.5 to 8 months), the total time needed to meet this requirement is estimated at approximately 9.5 to 11.5 months. Therefore, building in some buffer time to account for any possible delays due to complex hydrogeological settings, EPA is proposing that the sampling and analysis program can be developed no later than 6 months after the effective date of the final rule.

iii. Detection Monitoring Program and Assessment Monitoring Program Combined

To expedite groundwater monitoring and the initiation of corrective measures, EPA is proposing to require sampling and analysis of constituents listed in Appendix IV at the same time as those listed in Appendix III. The combined sampling and analysis of all Appendices III and IV constituents will expedite the initiation of corrective measures, where needed, by at least 6 months.

The existing CCR regulations establish a phased groundwater monitoring program, consisting of a separate detection monitoring program, assessment monitoring program, and corrective action program. Groundwater monitoring begins with detection monitoring by conducting statistical comparisons between (1) the background level of a constituent measured in one or more upgradient wells and (2) the level of that same constituent in a downgradient well. The constituents monitored in detection monitoring are listed in Appendix III and are generally constituents that are designed to provide early evidence of a potential release (e.g., are highly mobile). If the concentration of the constituent in the downgradient well is higher than the background concentration by a statistically significant amount, (i.e., a statistically significant increase (SSI) over background has been detected), this provides evidence of a potential release from the unit.

If an SSI is detected, the owner or operator must proceed to the next step, assessment monitoring. Assessment monitoring requires sampling and analysis for the full list of constituents included in Appendix IV. In assessment monitoring, concentrations of each Appendix IV constituent at downgradient wells are compared to a

groundwater protection standard established for each constituent (either a background level or a regulatory limit). Whenever assessment monitoring results indicate a statistically significant level (SSL) exceeding the groundwater protection standard has been detected at a downgradient well for any of the Appendix IV constituents, the facility must start the process for cleaning up the contamination by characterizing the nature and extent of the release and of site conditions that may affect the cleanup, and by initiating an assessment of corrective measures.

EPA is proposing to require that facilities simultaneously initiate sampling and analysis of all Appendix III and IV constituents at legacy CCR surface impoundments to expedite the cleanup of contamination from these abandoned unlined impoundments. EPA is proposing no other revisions to the existing groundwater monitoring requirements in §§ 257.90 through 257.95.

Although in 2015 EPA applied the same groundwater monitoring requirements to both existing and new CCR units, the phased approach to groundwater monitoring is best suited to situations where there is little likelihood of pre-existing contamination, such as for new units. A phased approach provides for a graduated response over time to the problem of groundwater contamination as the evidence of such contamination increases. This allows for proper consideration of the transport characteristics of CCR constituents in groundwater, while protecting human health and the environment. In contrast, at sites where the unit has potentially been leaking for a long period of time, these advantages are outweighed by the need to protect human health and environment by quickly detecting the constituents of concern in Appendix IV to expedite any necessary corrective action. See, *USWAG* 901 F.3d at 427–30. Moreover, there is good reason to believe that many legacy CCR surface impoundments are contaminating groundwater, given the large number of presently regulated CCR surface impoundments that have been found to be leaking.

iv. Detection Monitoring Program and Assessment Monitoring Program—Deadline for Collection and Analyses of Eight Independent Samples for Legacy CCR Surface Impoundments

EPA is proposing that no later than 24 months after the effective date of the final rule, owners or operators of legacy CCR surface impoundments initiate the detection monitoring program by

completing sampling and analysis of a minimum of eight independent samples for each background and downgradient well, as required by § 257.94(b). See proposed regulatory text at § 257.100(f)(4)(iii). Within 90 days after that, they must identify any SSLs over background levels for the constituents listed in Appendix III, as required by § 257.94. To expedite the time to initiate any required corrective action, EPA is also proposing that by this same deadline they initiate the assessment monitoring program by establishing groundwater protection standards and beginning the evaluation of the groundwater monitoring data for an SSL over groundwater protection standards for the constituents listed in Appendix IV as required by § 257.95. Then, if an SSL over a groundwater protection standard (GWPS) for any of the constituents listed in Appendix IV is found, the owner or operator of the legacy CCR surface impoundment must perform any required corrective action in accordance with §§ 257.96 through 257.98.

Several commenters on the ANPRM stated that it would be appropriate to have a fully operational groundwater monitoring systems in place and begin detection monitoring two years from the rule's effective date and then to follow the same groundwater monitoring requirements as units subject to the 2015 CCR Rule. These commenters said that as important as it is to begin detecting and addressing releases to groundwater, it is equally important that these complex systems be designed and installed correctly. According to the commenters, the design and installation of a groundwater monitoring system generally entails a number of activities, many of which must occur sequentially, including determining the uppermost aquifer, deciding whether to install a single or multiunit monitoring system, collecting and evaluating hydrogeological information that can be used to model the site, characterizing the site geology, characterizing the groundwater flow beneath the site, determining the flow direction and hydraulic gradient, establishing horizontal and vertical flow direction, determining hydraulic conductivity, determining groundwater flow rate, determining the monitoring wells' placement, selecting the drilling method, designing the monitoring wells, developing sampling and analysis procedures, choosing a statistical method for evaluating the data, and beginning detection monitoring.

v. Initial Groundwater Monitoring and Corrective Action Report for Legacy CCR Surface Impoundments

EPA is proposing to apply the existing requirements in § 257.90(e) to legacy CCR surface impoundments and that owners and operators of legacy CCR surface impoundments comply no later than January 31 of the year following the calendar year a groundwater monitoring system has been established (and annually thereafter). See proposed regulatory text at § 257.100(f)(4)(iv). This requires the preparation of an annual groundwater monitoring and corrective action report. The report must contain specific information identified in the regulations, including but not limited to maps; aerial images or diagrams showing the CCR unit and all upgradient (background) and downgradient wells; identification of any monitoring wells installed or decommissioned in the previous year; monitoring data collected under §§ 257.90 through 257.98, and a narrative discussion of any transition between monitoring programs (*i.e.*, detection and assessment monitoring). Since EPA is proposing to expedite the baseline monitoring initiation of detection monitoring, and initiation of assessment monitoring, the requirement to prepare and post the first annual groundwater monitoring and corrective action report should also be expedited. This will allow the public to review the groundwater monitoring results.

g. Closure and Post-Closure Care Criteria for Legacy CCR Surface Impoundments

The existing closure and post-closure care criteria in §§ 257.101 through 257.104 establish specific performance standards relating to the closure and the subsequent monitoring and maintenance of CCR units. These criteria are essential to ensuring the long-term safety of closing CCR units. A brief overview of the existing requirements is presented in Unit IV.A.2.f.i of this preamble.

The regulations currently provide two options for closing a CCR unit: closure by removal and closure with waste in place. See § 257.102(a). Each option establishes specific performance standards that must be met in their entirety. See § 257.102(c) and (d). If the performance standards for each option can both be met, the regulations allow a facility to select either of the options. However, a facility must meet all of the performance standards for the closure option it has selected, and if it cannot meet all of the performance standards for one option, then it must select the other option and meet all of the

performance standards for that option. See § 257.102(a).

The existing CCR regulations also include timeframes to initiate and complete closure activities, as well as criteria under which owners or operators may obtain time extensions due to circumstances beyond the facility's control. See §§ 257.101 through 257.102. Finally, owners and operators are required to prepare closure and post-closure care plans describing these activities. See §§ 257.102(b), 257.104(d). EPA is proposing to make the existing regulations applicable to legacy CCR surface impoundments as discussed specifically below.

First, based on the data gathered since 2015 from the currently regulated CCR unit universe, the Agency considers it highly unlikely that any legacy CCR surface impoundment has a composite liner that meets the requirements of § 257.71. EPA analyzed the list of inactive CCR facilities provided in the ANPRM comments and knows that almost all these facilities were opened prior to 1990 (one facility opened in 1996) before composite liner systems were typically installed. Unless legacy CCR surface impoundments are very different than impoundments at active facilities, EPA expects units of this age to be unlined as defined by § 257.71. Consistent with the USWAG decision and the existing regulations in § 257.101(a) mandating that all unlined (including clay-lined) impoundments must close, EPA is proposing to explicitly require that all legacy CCR surface impoundments initiate closure within 12 months of the effective date of final rule, rather than simply relying on the existing provision in § 257.101(a). See, proposed regulatory text at § 257.101(e). Legacy CCR surface impoundments pose unacceptable risks because they continue to impound liquid, even if closure has been initiated or a cover system has been installed.

Second, EPA is proposing to explicitly state that the alternative closure demonstration provisions in § 257.103(f) would not be applicable to legacy CCR surface impoundments. As a legacy CCR surface impoundment, by definition, is an inactive impoundment at an inactive facility, EPA does not believe that any facility will need to continue to use the unit. Because a continued need to use the disposal unit is a critical component of the alternative closure demonstrations, it appears that no legacy CCR surface impoundment could qualify under the existing provisions. Accordingly, EPA does not believe these provisions are relevant to legacy CCR surface impoundments.

i. ANPRM Comments Regarding Closure

Commenters on the ANPRM generally agreed that closure requirements are appropriate for legacy CCR surface impoundments. However, they disagreed on the precise requirements that would be appropriate. Some commenters said a legacy CCR surface impoundment that has been closed in place must be required to re-close if not closed in a manner that meets or exceeds the 2015 CCR Rule's provisions for closure in place. They also said that EPA must not exempt legacy CCR surface impoundments from closure requirements unless the impoundment was closed in full compliance with either the closure mandate for removal set out at § 257.102(c), or the closure performance standards, drainage and stabilization directives, and cover system requirements set out at § 257.102(d).

Other commenters on the ANPRM agreed that closure and post-closure requirements would be appropriate for legacy CCR surface impoundments but stated that the requirements should account for distinctive elements of some legacy CCR surface impoundments. According to these commenters, over decades, some legacy CCR surface impoundments have become ecosystems that support protected species or feature wetlands. These commenters raised concern that closure activities could compromise these ecosystems or species whereas leaving the environment undisturbed is preferable. These commenters stated that if EPA requires closure of these units, owners should not be required to obtain necessary approvals or mitigate impacts to aquatic resources or protected species under other laws. One commenter on the ANPRM said EPA should not require legacy CCR surface impoundments completing closure by removal to meet the groundwater performance standards.

Some commenters said EPA should rely on RCRA section 1006(b) to include a provision in any final rule addressing legacy CCR surface impoundments that any closure plan for a legacy CCR surface impoundment approved by a state or federal agency prior to the effective date of any new regulations would be considered compliant with the new regulations. According to these commenters, many units are or will be in the process of closing impoundments pursuant to consent orders, agreements, and/or state regulatory programs, and forcing units that are in active closure or that have completed closure to comply with a new set of requirements risks undoing the careful planning that has already occurred with state or

federal agencies. These commenters further stated that “such redundant and retroactive regulation also risks delaying the closure process and requiring closure work to be redone.” According to these commenters, confirming that units implementing closure plans approved by a state or federal agency would be deemed compliant with the final legacy CCR surface impoundment regulations (or that the underlying units are otherwise exempt from the final regulations) would avoid duplicative, retroactive regulation of such units, and would allow the regulated community and impacted states to rely on the closure plans already in place, and would prevent any delay in completion of closure activities that could be attributed to uncertainty of the application of requirements for the final rule.

Although several commenters alleged that the closure of legacy CCR surface impoundments would itself present greater risks than leaving the disposal unit in its existing state, no commenter presented any data or analysis to support their claims. EPA also lacks a factual basis to exempt legacy CCR surface impoundments in the process of completing closure by removal from the requirement to meet the groundwater performance standards. In the absence of any record to support a conclusion that these suggestions meet the statutory standard in RCRA section 4004(a), EPA cannot adopt them. EPA invites comments from those with concrete data or analysis, if any, about any specific legacy CCR surface impoundments as it relates to these questions.

EPA also disagrees that it would be appropriate to establish an exemption for facilities that are currently in the process of closing under state requirements. The commenters provided no factual record of the various state information regarding particular state requirements, but merely generically reference the existence of state requirements. This is insufficient information for the Agency to evaluate how the state requirements compared to the federal requirements. Such a factual record would be necessary to support any kind of exemption or other action pursuant to RCRA section 1006(b). More to the point, as discussed previously, the appropriate mechanism to address concerns about potentially duplicative state and federal requirements is through Congressionally-mandated process in RCRA section 4005(d), under which a state seeks approval to operate its permit program in lieu of the federal program, rather than this rulemaking.

ii. Preparation of a Written Closure Plan for Legacy CCR Surface Impoundments

EPA is proposing that owners and operators of legacy CCR surface impoundments comply with the existing requirements of § 257.102(b) requiring the preparation of a written closure plan. See proposed regulatory text at § 257.100(f)(5)(i). The closure plan describes the steps necessary to close a CCR unit at any point during the active life of the unit based on recognized and generally accepted good engineering practices. 40 CFR 257.102(b)(1). The plan must set out whether the closure of the CCR unit will be accomplished by leaving CCR in place or through closure by removal and include a written narrative describing how the unit will be closed in accordance with the section, or in other words, how the closure will meet all the performance standards in the regulations. 40 CFR 257.102(b)(1)(i). If the CCR is left in place, the closure plan must include a description of the final cover system and how the final cover system will achieve the regulatory performance standards. If the base of the impoundment intersects with groundwater, the closure plan would need to discuss the engineering measures taken to ensure that the groundwater had been removed from the unit prior to the start of installing the final cover system, as required by § 257.102(d)(2)(i). The closure plan would also need to describe how the facility plans to meet the requirements in § 257.102(d)(1) to “control, minimize or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste and releases of CCR, leachate, or contaminated run-off to the ground or surface waters.” This could include for example, the installation of engineering controls that would address the post-closure infiltration of liquids into the waste from all directions, as well as any post-closure releases to the groundwater from the sides and bottom of the unit. The written closure plan must also provide a schedule for completing all activities necessary to satisfy the closure criteria of the rule. *See also* 80 FR 21410–21425, April 17, 2015.

Some commenters said EPA should provide phased and reasonable compliance deadlines for the development of closure plans prior to initiation of any groundwater monitoring or closure work. Other commenters acknowledged the Agency provided 18 months from promulgation of the 2015 CCR Rule for plants to develop their closure and post-closure plans and that the amount of time was

partly dictated by the Agency's commitment to harmonizing the 2015 CCR Rule with the ELG Rule. Commenters shared that consideration of new ELG requirements would not be an issue for legacy CCR surface impoundments; therefore, a shorter planning horizon is reasonable for legacy CCR surface impoundments such as 6 months from the effective date of a legacy CCR surface impoundment rule. The commenters further said that planning is only the first step while unit closure itself can take years depending on factors such as the size and type of unit. Legacy CCR surface impoundments would likely require similar closure timeframes, and possibly additional time if site-specific accommodations are required such as the presence of a listed or endangered species. Some commenters agreed that the closure timeframe provided in the 2015 CCR Rule may be reasonable for legacy CCR surface impoundments. Other commenters said six months should be the bare minimum for owners to develop any closure and post-closure care plans for legacy CCR surface impoundments as closure activities cannot begin until the closure plan is in place.

When preparing the closure plan, the owner or operator would first need to hire a contractor to complete the report (1–2 weeks). Next, it is assumed that the contractor will need to review site-specific documents, assessments, and analyses that were completed earlier to meet requirements for other parts of the rule that may impact the closure plan. Examples of existing documents and assessments reviewed may include history of construction, initial structural stability assessment, initial safety factor assessment, initial hazard potential classification, hydraulic and hydrologic analyses for inundation maps and potential impact area, annual inspections, groundwater monitoring system, and groundwater sampling and analysis reports. Assuming all preceding analyses are completed by their deadlines of 6 months after the effective date of the final rule, the next step is to review existing documents and assessments (estimate 4–6 weeks). The next step is to prepare the written closure plan with the requirements in § 257.102(b) through (j). Since the listed activities are primarily desktop-related and depend on predecessor requirements, EPA is proposing a deadline of 12 months after the effective date of the rule to complete the closure plan. EPA is expediting this deadline for the reasons described above in Unit IV.A.2.a.ii of this preamble.

iii. Preparation of a Written Post-Closure Care Plan for Legacy CCR Surface Impoundments

EPA is proposing that owners and operators of legacy CCR surface impoundments would be required to comply with the existing requirement in § 257.104(d) regarding the preparation of a written post-closure. See, proposed regulatory text at § 257.100(f)(5)(ii). Section 257.104(d) requires that an owner or operator of a CCR unit prepare a written post-closure plan. The content of the plan includes among other things, a description of the monitoring and maintenance activities required for the unit and the frequency that these activities will be performed.

When developing the post-closure care plan, EPA assumes the contents of the P.E.-certified plan are stated in the rule § 257.104(d)(1)(i) through (iii) and can be summarized as planned monitoring and maintenance activities, contact information during post-closure care period and planned uses of the property. The steps to prepare the post-closure care plan are assumed to be the same as the closure plan, with different analysis needed for the post-closure care period. Since the listed activities are primarily desktop-related and depend on a number of predecessor requirements, described in Unit IV.A.2.g.i of this preamble, related to the closure plan, EPA is proposing to require the post-closure care plan no later than 12 months after the effective date of the final rule. EPA is expediting this deadline for the reasons described above in Unit IV.A.2.a.ii of this preamble.

iv. Initiation of Closure for Legacy CCR Surface Impoundments

As discussed above, the current record indicates that legacy CCR surface impoundments are largely, if not entirely, unlined, and therefore, EPA is proposing that they be subject to the existing requirement to initiate closure that are applicable to other unlined CCR surface impoundments. See 40 CFR 257.101. Specifically, EPA is proposing that owners and operators of legacy CCR surface impoundments initiate closure no later than 12 months after the effective date of the final rule. See proposed regulatory text at § 257.101(e)(1). This is 30 months sooner than the earliest date under the 2015 CCR Rule that owners or operators of CCR units were required to initiate closure and is expedited for the reasons described above in Unit IV.A.2.a.ii of this preamble. EPA considered requiring initiation of closure sooner but believes that 12 months is the minimum amount

of time necessary to collect the information needed to determine whether to close the unit in place or close by removal. Such information would include the identification and delineation of the legacy CCR surface impoundment, the structural stability of the unit, the hydrogeology of the site, and other site characteristics of the site, and whether any of the uppermost aquifer has been contaminated, as well as any other relevant engineering information needed to design the closure. Because many of the legacy CCR surface impoundments have not been monitored for some time, this information may not be currently available. However, most of this information can be obtained through compliance with the groundwater monitoring and corrective action requirements that EPA is proposing to establish, as discussed above. Twelve months will provide sufficient time to complete the steps necessary to obtain this information. Once the owner and/or operator has the necessary information, they can develop a closure plan and initiate closure.

One commenter said there should be no mechanism to extend the time to initiate closure. EPA agrees and, consistent with the existing requirements for inactive unlined impoundments in § 257.101(a), the Agency is not proposing to establish a mechanism to extend the deadline to initiate closure.

Finally, as an alternative to requiring the closure of a legacy CCR surface impoundment, the Agency solicits comment on whether the regulations should provide owners and operators the option to retrofit a legacy CCR surface impoundment in accordance with the retrofit requirements in § 257.102(k).

v. Deadline To Complete Closure for Legacy CCR Surface Impoundments

The existing CCR regulations currently require (at § 257.102(f)) an owner or operator of existing and new CCR surface impoundments generally to complete closure activities within five years from initiating closure. The regulations also establish the conditions for extending this deadline, as necessary, including documentation requirements. EPA is proposing that owners and operators of legacy CCR surface impoundment comply with the existing closure completion timeframes in § 257.102(f). Most commenters agreed that units should be provided the same amount of time to complete closure as in the existing provisions.

vi. Post-Closure Care for Legacy CCR Surface Impoundments

The existing post-closure care criteria require the monitoring and maintenance of units that have closed in place for at least 30 years after closure has been completed. 40 CFR 257.104. During this post-closure period, the facility would be required to continue groundwater monitoring and corrective action, where necessary. EPA is proposing to apply these existing requirements to legacy CCR surface impoundments without revision. These criteria are essential to ensuring the long-term safety of legacy CCR surface impoundments.

h. Recordkeeping, Notification, and Internet Posting Criteria for Legacy CCR Surface Impoundments

The 2015 CCR Rule required at §§ 257.105 through 257.107 for owner or operators of CCR units to record certain information in the facility's operating record. In addition, owners and operators are required to provide notification to states and/or appropriate Tribal authorities when the owner or operator places information in the operating record, as well as to maintain a CCR website for this information. Commenters on the ANPRM agreed that recordkeeping, notification and website reporting requirements are appropriate for legacy CCR surface impoundments.

EPA is proposing that owners and operators of legacy CCR surface impoundments be subject to the existing recordkeeping, notification and website reporting requirements in the CCR regulations. The CCR regulations require the owner or operator of a CCR unit(s) to maintain files of all required information (e.g., demonstrations, plans, notifications, and reports) that supports implementation and compliance with the rule. Each file must be maintained in the operating record for a period of at least five years following submittal of the file into the operating record. Submittal into the operating record is required at the time the documentation becomes available or by the specific compliance deadline. Section 257.105 contains a comprehensive listing of each recordkeeping requirement.

Owners or operators are also required to notify State Directors and/or the appropriate Tribal authority when specific documents have been placed in the operating record and on the owner's or operator's CCR website. In most instances, these reports must be certified by a P.E. and may, in certain instances, be accompanied by additional information or data supporting the notification. Notification requirements can be found at § 257.106, and are

required for location criteria, design criteria, operating criteria, groundwater monitoring, corrective action, closure, and post-closure care.

Commenters on the ANPRM agreed that owners or operators of CCR facilities should be required to establish a publicly accessible website where facilities are required to post relevant information demonstrating compliance with all applicable requirements. They agreed the website should not be hosted by the state or EPA. They also said the website should be required to be activated by the effective date of the final rule.

EPA is proposing that owners and operators of legacy CCR surface impoundments are also required to establish and maintain a website titled, "CCR Rule Compliance Data and Information." Unless provided otherwise in the rule, information posted to the publicly accessible internet site must be available for a period no less than 5 years from the initial posting date for each submission. Posting of information must be completed no later than 30 days from the submittal of the information to the operating record. EPA is proposing that owners and operators of legacy CCR surface impoundments have 30 days from the effective date of the final rule to post applicable information on their CCR website.

B. CCR Management Unit Requirements

EPA is proposing to establish requirements to address the risks from currently exempt solid waste management of CCR that involves the direct placement of CCR on the land. Information obtained since 2015 demonstrates that these exempt solid waste management practices are currently contaminating groundwater at many sites, and at others, have the potential to pose risks commensurate with the risks associated with currently regulated activities. The specific solid waste management activities at issue are: CCR disposal in surface impoundments and landfills that closed prior to the effective date of the 2015 CCR Rule, disposal in inactive CCR landfills, and any solid waste management that involves the placement or receipt of CCR directly on the land.

As discussed in more detail below, EPA estimates that these solid waste management practices could pose lifetime cancer risks from arsenic as high as 2×10^{-5} to 1×10^{-3} (i.e., 2 to 100 cases of cancer for every 100,000 individuals exposed), depending on the specific management practice. In addition, EPA has identified recent

damage cases, described in Unit IV.B.2 of this preamble, indicating that these management practices have contaminated groundwater at currently regulated facilities,¹⁵ through releases of constituents commonly found in CCR, such as arsenic, lithium and molybdenum.

Based on these data, EPA is proposing to establish a new category of units that would be subject to a set of requirements tailored to the characteristics of such units and the risks that they present. These requirements would include the existing criteria in the CCR regulations for groundwater monitoring, corrective action, closure, and post-closure care.

1. Risk Analysis of CCR Management Units

a. Summary of 2014 Risk Record

EPA conducted a national-scale, probabilistic analysis in 2014 titled, Human and Ecological Risk Assessment of Coal Combustion Residuals (2014 Risk Assessment),¹⁶ that characterized potential risks to human and ecological receptors associated with leakage from CCR surface impoundments and landfills in operation at that time. A combination of models was used to predict fate and transport of contaminants through the environment, receptor exposures, and the resulting risks to human and ecological receptors. The specific exposure routes evaluated were: (1) Human inhalation of particulate matter blown from open management units, (2) Human ingestion of crops and livestock raised on nearby fields, (3) Human ingestion of groundwater used as a source of drinking water, (4) Human ingestion of fish caught from freshwater streams, and (5) Ecological contact with and ingestion of surface water and sediment. Site-specific data were used where available, supplemented by regional and national data to fill data gaps, to capture the variability of waste management practices, environmental conditions, and receptor behavior. EPA reported risks for both highly exposed individuals and more moderately exposed individuals. Risks to highly exposed individuals represent a reasonable maximum estimate that members of the general population might be exposed to, which were

¹⁵ Under part 257, subpart D, new and existing CCR landfills and surface impoundments, including any lateral expansions of these units, as well as inactive CCR surface impoundments are currently regulated.

¹⁶ U.S. EPA. 2014. "Human and Ecological Risk Assessment of Coal Combustion Residuals." RIN 2050-AE81. Office of Solid Waste and Emergency Response. Washington, DC. December.

calculated as the 90th percentiles of all probabilistic model results. Risks to moderately exposed individuals represent a more typical estimate that members of the general population might be exposed to, which were calculated as the 50th percentiles of all probabilistic model results.

Under RCRA, EPA typically relies on a risk range to determine the point at which regulation is appropriate. EPA uses as an initial cancer risk “level of concern” a calculated risk level of 1×10^{-5} (one in one hundred thousand) or a hazard quotient (HQ) above 1.0 for any noncarcinogenic risks. For example, wastestreams for which the calculated high end individual cancer-risk level is 1×10^{-5} or higher generally are considered candidates for regulation. Wastestreams whose risks are calculated to be 1×10^{-4} (one in ten thousand) or higher generally will be considered to pose a substantial present or potential hazard to human health and the environment and generally will be regulated. Wastestreams for which these risks are calculated to be 1×10^{-6} (one in one million) or lower, and lower than 1.0 HQ or environmental risk quotients for any noncarcinogens, generally will be considered not to pose a substantial present or potential hazard to human health and the environment and generally will not be regulated. See 80 FR 21449; 59 FR 66075–66077, December 22, 1994.

EPA first evaluated national-scale risks, as documented in the 2014 Risk Assessment, which provide a snapshot in time of potential risks across the country. This was accomplished by weighting risks from individual management practices in proportion to the anticipated prevalence of those practices. National-scale risks provide important context as to whether risks are a systemic issue that warrant national regulations or are limited in scope and better addressed through more targeted actions. The Agency’s evaluation found that the management practices that EPA believed were generally in current use at surface impoundments and landfills were likely to pose risks to human health through groundwater exposure within the range that EPA typically considers warranting regulation. For highly exposed individuals, the cancer risks from arsenic due to the operation of surface impoundments were as high as 2×10^{-4} and noncancer risks from both lithium and molybdenum were as high as an HQ of 2, while the cancer risks associated with the operation of landfills were estimated to be as high as 5×10^{-6} from the ingestion of arsenic-contaminated drinking water. In contrast, all risks for

moderately exposed individuals fell below EPA’s risk range. This was largely attributed to the fact that many facilities are located next to major water bodies and so contaminant plumes were frequently intercepted by these water bodies before they could reach private wells.

EPA next evaluated the risks associated with individual management practices at surface impoundments and landfills. This was accomplished by filtering the national-scale model runs to focus only on those that included the practice of interest and using the filtered set of runs to calculate risks associated with that specific practice. These individual risks provide important context about the range of contaminants and practices that could pose risk at individual sites. The Agency’s evaluation identified two specific management practices that could lead to risks higher than those identified in the national risk estimates.

The first practice EPA evaluated was the disposal of CCR in unlined and clay-lined units. Management in unlined surface impoundments resulted in cancer risks for arsenic up to 3×10^{-4} , as well as noncancer risks for lithium up to an HQ of 3, molybdenum up to an HQ of 4, and thallium up to an HQ of 2. Management in unlined landfills resulted in cancer risks for arsenic up to 2×10^{-5} . The larger increase in arsenic risks identified for unlined landfills above those for national-scale landfills (2×10^{-5} vs. 5×10^{-6}) compared to unlined and national-scale impoundments (3×10^{-4} vs. 2×10^{-4}) is because a larger proportion of landfills nationwide were initially modeled as having a liner. Since promulgation of the 2015 CCR Rule, it has become clear that more landfills are unlined than originally estimated. Thus, it is anticipated that national-scale risks for landfills would actually be closer to those for unlined units (2×10^{-5}), rather than the lower estimates reported in the 2014 Risk Assessment.

Although clay-lined units tended to have lower risks than unlined units, they still had potential to result in risks within the range that EPA considers for regulation under RCRA. Management in clay-lined impoundments with a liner thickness of three feet resulted in cancer risks for arsenic of up to 7×10^{-6} and noncancer risks for lithium up to an HQ of 2, while management in similarly lined landfills resulted in cancer risks for arsenic up to the 1×10^{-5} . The larger increase in arsenic risks for unlined impoundments above those for clay-lined impoundments (1×10^{-5} vs. 7×10^{-6}) compared to unlined and clay-lined landfills (2×10^{-5} vs. 1×10^{-5})

is because the layer of low conductivity clay counteracts the hydraulic head in impoundments that would otherwise freely drive greater volumes of leachate into the subsurface.¹⁷ In contrast, leachate generation in both types of landfills is limited far more by the rate of precipitation. As a result, EPA further considered how reducing the modeled clay liner thickness of impoundments to the minimum allowable standard of two feet would affect arsenic risk and found it would increase to as high as 2×10^{-5} .

The second practice evaluated was the management of wastes with an extreme pH. In particular, empirical porewater data revealed that co-management of CCR with other wastes in surface impoundments had the potential to result in a highly acidic pH, cancer risks for arsenic up to 1×10^{-3} , and noncancer risks for cobalt and mercury up to an HQ of 13 and 5, respectively. Laboratory leaching test data also indicated that highly acidic and basic CCR wastes have the potential to leach similarly high arsenic concentrations, up to an order of magnitude higher than under more neutral conditions. Only a small number of previous landfill model runs considered acidic conditions based on the information available about conditions in active units; identified risks for these units were driven by more basic conditions. Thus, to the extent that at conditions at either extreme of the pH scale are more prevalent than previously estimated, it is likely that overall risks from disposal in both surface impoundments and landfills would be even higher than modeled.

EPA acknowledged in the 2014 Risk Assessment that there were some additional management practices that may result in higher risk at individual sites, but that could not be quantitatively modeled with the data available at the time. One specific example provided was of CCR disposal below the water table. EPA was unable to quantitatively model the associated risks as there was little data on how common this practice was or the extent to which it could affect groundwater chemistry. Because EPA could not quantitatively model these management practices (and because the Agency had no information to indicate that it was a current, widespread management practice), EPA noted only that, based on its review of damage cases, the damage from the placement of CCR in sand and

¹⁷ The somewhat higher risks identified for clay-lined landfills compared to similarly lined impoundments are likely related to site-specific conditions, such as where in the country these units are located.

gravel pits was almost always associated with CCR being placed in contact with water, which indicated that the placement of CCR in contact with water can lead to higher risks than from dry disposal. 80 FR 21352, April 17, 2015. EPA further explained that “in this situation, the sorption that occurs in the unsaturated zone of the risk assessment model does not occur in the field. This and other site-specific risk factors could lead to additional contamination beyond what was modeled nationwide.” 2014 Risk Assessment at pages 5–48. As a consequence, EPA specifically included sand and gravel pits that received CCR in the definition of CCR landfills covered by the regulations. 80 FR 21354.

EPA believes the groundwater data that have since been collected from monitoring systems installed around surface impoundments and landfills generally validates the findings of the 2014 Risk Assessment. For example, one limited analysis from 2019 of the groundwater data collected as part of the required facility monitoring programs found arsenic, molybdenum, and lithium are the constituents most likely to be found at concentrations above GWPS in compliance wells.¹⁸ These data broadly confirm that these three constituents, which were identified as the primary risk drivers by national-scale modeling, are among those found most frequently at elevated levels in site groundwater monitoring wells.

b. Risks From Historical Disposal Units

The 2014 Risk Assessment could not directly model risks associated with disposal units that had previously closed or become inactive, as there was little to no information available about the numbers, locations, and characteristics of these historical units. However, based on information obtained since 2015, EPA now expects that risks posed by the management of CCR in inactive or closed landfills and closed surface impoundments at electric utilities could pose risks to nearby receptors that are, at a minimum, similar to the levels and kinds of risks posed by the currently regulated universe of CCR landfills and surface impoundments.

The unregulated units contain similar types of ash and are located on the same facilities, often in close proximity to and sometimes underneath the currently regulated units. Therefore, the risks associated with historical

impoundments and landfills are expected to be similar to those modeled for the currently regulated units. Even if the historical impoundments have subsequently been at least partially dewatered or have undergone some kind of closure, the current absence of impounded water does not negate the releases that occurred during operation of the unit. In addition, if precipitation can continue to freely migrate into the unit, (e.g., because it lacks an effective cover system), any leachate generated as a result would be a potential ongoing source of contamination, particularly where the unit is already leaking or in contact with groundwater. In general, it is expected that these historical units have been present for longer than the currently operating units at the same sites and so would have had more time to leak. As a result, previous and ongoing releases from these historical units could potentially be greater and have migrated further from the unit than releases from the currently regulated universe of units. Furthermore, as described below, there are a number of additional reasons to believe that the potential magnitude of releases from historical disposal is even greater than EPA modeled in 2014 for the currently regulated units.

First, many facilities have historically disposed of CCR in landfills and surface impoundments that lack adequate liner systems. Based on surveys conducted by EPA between 2009 and 2010 (hereafter “EPA surveys”), EPA estimated in the 2014 Risk Assessment that 33% of landfills and 17% of impoundments had composite liners.¹⁹ It has since become clear that even fewer units are lined. EPA’s review of liner demonstration documents posted on facilities’ CCR websites found that only 8% of landfills and 6% of impoundments in operation attest to having a standard or alternative composite liner. It is unlikely that historical units were lined at higher rates, particularly those constructed prior to the promulgation of minimum standards for disposal in RCRA subtitle D landfills in 1991. See, 40 CFR part 257, subpart A and part 258. Most of the coal-fired utilities in the United States were constructed before 1990.²⁰ Therefore, the risks associated with historical disposal units are likely to be at least as high as 2×10^{-5} based on the

estimates of the risks associated with the management of CCR in unlined landfills in the 2014 Risk Assessment. This risk estimate for historical landfills would be almost an order of magnitude higher than the national-scale risks associated with the management of CCR in landfills modeled in the 2014 Risk Assessment. This risk estimate would also be twice the level of risk that EPA typically considers for regulation and is the same level of risk as those associated with the clay-lined CCR surface impoundments that the D.C. Circuit required to close.

Second, some facilities conduct coal preparation activities prior to combustion. These activities may include coal handling by conveyor systems, coal washing for removing mineral matter, and coal “sizing” to reduce the average particle size of coal. The wastes generated from coal preparation activities are collectively referred to as “coal refuse.” Some facilities have been known to dispose of coal refuse together with CCR. Such co-disposal can have a pronounced effect on the leaching behavior of CCR because of the potential for the refuse to make the overall waste pH far more acidic. Available Leaching Environmental Assessment Framework (LEAF) leaching data considered in the 2014 Risk Assessment show that multiple Appendix IV constituents are most soluble at an acidic pH and thus able to leak at higher rates. As a result, EPA found modeled risks were often highest when CCR was disposed with coal refuse. For example, the modeled cancer risks for the co-disposal of ash and coal refuse (pH 1.7–8.2) in surface impoundments ranged between 1×10^{-3} for trivalent arsenic to 4×10^{-4} for pentavalent arsenic. Non-cancer risks were similarly high, ranging between and an HQ of 13 for cobalt and HQ of 14 for pentavalent arsenic to 26 for trivalent arsenic, based on the ingestion of contaminated drinking water.

The practice has declined over time. A survey conducted by Electric Power Research Institute (EPRI) in 1995 showed 34 percent of unlined landfills and 68 percent of unlined surface impoundments actively managed CCR with coal refuse.²¹ In contrast, EPA surveys indicated that, by 2014 this management practice had declined to around 5% of all operating units. EPA’s 2014 national-scale modeling was based on the 5% reported in the EPA surveys, and as a consequence, this practice had minimal influence on the overall

¹⁹ U.S. EPA. 2014. “Human and Ecological Risk Assessment of Coal Combustion Residuals.” RIN 2050–AE81. Office of Solid Waste and Emergency Response. Washington, DC. December.

²⁰ United States Energy Information Administration. 2017. “Most Coal Plants in the United States were Built Before 1990.” Accessed online at: <https://www.eia.gov/todayinenergy/detail.php?id=30812>.

¹⁸ Environmental Integrity Project. 2019. “Coal’s Poisonous Legacy: Groundwater Contaminated by Coal Ash Across the U.S.”

²¹ EPRI. 1997. “Coal Combustion By-Products and Low-Volume Wastes Comanagement Survey.” Palo Alto, CA. June.

nationwide risk estimates in the 2014 Risk Assessment. However, it is clear from the EPRI data that management of CCR with coal refuse used to be far more common. Therefore, the risks associated with historical disposal units, such as closed units or inactive landfills, are likely to be higher than the national-scale risks reported in the 2014 Risk Assessment.

Finally, it is known that facilities have disposed of CCR in units that either have been constructed beneath the water table or have since become inundated with groundwater. EPA's review of the location restriction demonstrations posted on facilities' CCR websites found that approximately 31% of operating impoundments have waste below the water table; similar data are not available for landfills. EPA previously identified disposal below the water table as a management practice that could result in higher risks than those modeled in the 2014 Risk Assessment. Since promulgation of the 2015 CCR Rule, it has become apparent that the practice of disposing of CCR below the water table is more common than previously understood. Given that most historical landfills and impoundments are located on the same sites as the currently operating units, and are therefore located in the same hydrogeologic environments, there is good reason to believe that such units at some of these sites were constructed in contact with the water table or have since become inundated with groundwater.

The greater prevalence of this management practice has significant implications for the risks associated with CCRMU. First, a CCR landfill saturated with water during operation, either continuously or intermittently, would have behaved more like an operating CCR surface impoundment, even though such a unit would not have the hydraulic head from ponded water present in an operating impoundment. The hydraulic head from the ponded water in an operating impoundment unit allows for continual leaching of contaminants from the CCR and drives the resulting leachate into underlying soils and potentially into the underlying aquifer. However, where any part of the unit is actually constructed below the water table, the conditions caused by the continuous saturation of the CCR by the groundwater flowing in and out of the unit allow the contaminants in the unit to continuously leach directly into the nearby ground and surface waters, even without any downward pressure from hydraulic head pushing leachate out of the unit. Second, for the same reasons, closed units and inactive

landfills that continue to be saturated by groundwater will continue to present these same risks, even though no additional CCR will have been added to the unit.

Further there are several ways in which disposal below the water table can result in higher risks than EPA originally estimated in 2014. One of these is that it has the potential to alter groundwater chemistry in ways that increase either the solubility or mobility of CCR contaminants. This is due to the residual, unburnt organic matter in CCR serving as a carbon source (*i.e.*, substrate, electron donor) for bacteria in the soil. Bacteria preferentially use any dissolved oxygen (O_2) for oxidation of organic matter (*i.e.*, electron transfer from the organic matter to oxygen) because this yields the greatest energy returns for the bacteria. With a sufficient source of biodegradable organic matter, bacterial consumption of oxygen can outpace replenishment of dissolved oxygen that occurs through diffusion from the atmosphere and infiltration of precipitation. Depletion of oxygen is more likely to occur in saturated soils because the constant presence of water allows biological activity to proceed unimpeded by periods of drying, the relatively slow flow rate of groundwater does not transport dissolved oxygen from the upgradient side of the unit fast enough to outpace consumption across the footprint of the unit, and sustained saturation of the soil limits oxygen exchange with the atmosphere. In the absence of oxygen, bacteria will instead use nitrate, manganese, iron, sulfate, and other compounds for reduction of organic matter (*i.e.*, electron transfer to organic matter from other compounds). Such reducing conditions will not affect all constituents equally, serving to mobilize some and immobilize others. However, reducing conditions can mobilize arsenic, the primary source of risks identified in the 2014 Risk Assessment, in two primary ways. First, the transformation of iron, sulfur, and other minerals in the ash and soil can free arsenic that was either complexed with or sorbed onto these minerals. Second, reducing conditions can change the dominant oxidation state of arsenic (*i.e.*, how many electrons the atom has gained or lost in its present state), resulting in a more mobile form that is not retained as well on the soil surface.

Research conducted since the 2014 Risk Assessment has better documented the potential effects of disposal below the water table on leakage from CCR units. Studies published in 2022 examined, among other things, the degree to which environmental conditions can differ within the same

closed impoundment, both above and below the water table.^{22 23} Specifically, arsenic concentrations measured in the water intermingled with CCR collected from beneath the water table were as high as 4,100 $\mu\text{g/L}$ due to the presence of reducing conditions and a near neutral pH of 8. That concentration is substantially higher than 20 $\mu\text{g/L}$, measured from the same ash with LEAF Method 1313 at a similar pH, or 780 $\mu\text{g/L}$, which is the 90th percentile of all impoundment porewater measurements previously compiled by EPA. Altogether this indicates that the 2014 Risk Assessment, which relied on data from these two sources, may have underestimated the potential magnitude of leakage from CCR units under reducing conditions. Data collected using LEAF methods, like all standardized leaching tests, tend to reflect oxidizing conditions due to contact between the sample and the atmosphere during sample collection and laboratory analysis. It has since been recognized that further analysis of leachate data with geochemical speciation models may be warranted when field conditions diverge from those present in the laboratory setting (*e.g.*, reducing conditions).²⁴ Data from the Agency's empirical porewater dataset may reflect reducing conditions to some degree because the ash in these units remains saturated. Yet, there are reasons to believe that reducing conditions would not be as common or extreme in operating impoundments. Operating impoundments are open to the air, frequently have new water sluiced into them, and may be periodically dredged. These conditions introduce oxygen into the impoundment far faster and more frequently than a closed and capped impoundment. For all these reasons, it is likely that long-term disposal of CCR below the groundwater table, whether in a closed or partially dewatered impoundment, a closed or inactive landfill, or other method of management, can pose risks

²² Wang, X., A.C. Garrabrants, Z. Chen, H.A. van der Sloot, K.G. Brown, Q. Qiu, R.C. Delapp, B. Hensel, and D.S. Kosson. 2022. "The Influence of Redox Conditions on Aqueous-Solid Partitioning of Arsenic and Selenium in a Closed Coal Ash Impoundment." *Journal of Hazardous Materials*. 428:128255.

²³ Wang, X, H.A. van der Sloot, K.G. Brown, A.C. Garrabrants, Z. Chen, B. Hensel, and D.S. Kosson. 2022. "Application and Uncertainty of a Geochemical Speciation Model for Predicting Oxyanion Leaching from Coal Fly Ash under Different Controlling Mechanisms." *Journal of Hazardous Materials*. 438:129518.

²⁴ U.S. EPA. 2019. "Leaching Environmental Assessment Framework (LEAF) How-To Guide: Understanding the LEAF Approach and How and When to Use It." Office of Land and Emergency Management. Washington, DC. May.

similar to or even greater than previously modeled for operating surface impoundments.

Based on the various lines of evidence outlined above and confirmed by the damage cases discussed in the next Unit of the preamble, historical disposal practices for CCR diverge from current practices in several material ways. Each of these practices individually have the potential to result in risks even higher than those previously modeled for the currently operating universe of CCR units, and a combination of these practices could push risks even higher.

2. Damage Cases

EPA has a long history of considering damage cases in its regulatory decisions under RCRA. RCRA specifically directs EPA, when making a Regulatory Determination for CCR, to consider “documented cases in which danger to human health and the environment from surface run-off or leachate has been proved,” demonstrating that such information is to carry great weight in decisions of whether and how to regulate such wastes. 42 U.S.C. 6982(n)(4). See also 42 U.S.C. 6982(n)(3). In addition, damage cases are among the criteria EPA must consider under its regulations for determining whether to list a waste as a “hazardous waste.” See 40 CFR 261.11(a)(3)(ix). EPA also relied on damage cases to develop the specific requirements for CCR in part 257, subpart D. See, 80 FR 21452–21459.

Damage cases generally provide direct evidence of both the extent and nature of the potential risks to human health and the environment that have resulted from actual waste management practice. For example, in the 2015 CCR Rule, EPA relied on damage cases to identify actual management practices that resulted in harm above and beyond that already identified through modeling. Based on the damage cases, EPA identified several additional constituents (antimony, barium, beryllium, chromium, selenium, and lead) that were added to the Appendix IV list for groundwater monitoring. For CCRMU, EPA is relying on the damage cases to further support the results of the modeling discussed in the preceding Unit of this preamble and to better understand the characteristics of the sites and units, as well as the management practices, in order to develop appropriate requirements.

a. Data Sources Reviewed

In response to the ANPRM, EPA received comments that contained information stating that groundwater contamination was occurring at many

sites from federally unregulated units such as inactive landfills, closed landfills, and fill. Additionally, EPA received comments, reports, and data from states, nongovernmental organizations, citizen groups, and other stakeholders, regarding groundwater contamination from currently unregulated CCR sources. EPA also reviewed comments received on the ANPRM. One commenter, Earthjustice et al., said:

EPA only regulates CCR landfills that were active after October 2015, which leaves hundreds of coal ash landfills [to] escape all closure, source control, and remediation requirements. Commenters now know that these coal ash landfills are currently causing serious groundwater contamination. The analysis of the Ashtracker²⁵ data presented in these comments shows that the vast majority of CCR landfills threaten human health and the environment. Data indicate that distinctions based on landfill type or the date that the unit ceased operation are effectively meaningless from a risk perspective. Unless EPA addresses the threats posed by inactive landfills, the CCR Rule will continue to fall short of the RCRA protectiveness standard. Serious and ongoing harm caused by coal ash will never be resolved, until EPA applies its regulatory oversight to these toxic open dumps.

Earthjustice et al., also provided a list of 47 potential inactive landfills²⁶ identified in EPA Information Request Responses from Electric Utilities,²⁷ EPA Human and Ecological Risk Assessment of Coal Combustion Residuals (Dec. 2014),²⁸ and U.S. Energy Information Administration (EIA) Monthly Electric Generator Inventory (“EIA 860M”).²⁹

EPA reviewed these data and found the information used to support the 2015 CCR Rule included EIA data that estimated which power plants disposed of CCR either wet (in CCR surface impoundments) or dry (in CCR landfills) to estimate the number of CCR units on-site. These 2014 estimates of CCR units were not always verified at the time, nor did the data contain actual unit names or exact numbers of units on-site, nor were the commenters data unit specific

with unit names or other identifying features. However, since 2016,³⁰ the Agency has been reviewing the documents posted on facilities’ CCR websites for compliance with CCR regulations. Specifically, EPA has reviewed groundwater monitoring reports, assessment of corrective measures reports, corrective measures progress reports, remedy selection reports, history of construction reports, closure plans and reports, and fugitive dust control plans for facilities with CCR websites from 2018, 2019, 2020, and 2021. Through the review of information posted by facilities on CCR websites and implementation of the 2015 CCR Rule, EPA has better estimates of the different types of units at regulated facilities. Some of the differences between the 2014 Risk Assessment data, 2014 Regulatory Impact Analysis (RIA), and the current known universe of regulated facilities are due to differences in reporting between cells versus units, general assumptions about the number of wet/dry units at a facility, changes in unit names over time due to different waste management practices, and inclusion of storage impoundments that were later determined to not contain CCR and therefore were not CCR surface impoundments.

Through review of groundwater monitoring and corrective action reports, EPA found many instances where the owners or operators of CCR facilities claimed that the detection of an SSI or SSL in concentrations of Appendix III or IV constituents in groundwater came from a CCRMU rather than the monitored regulated CCR unit. Whenever a facility determines that there is an SSI over background levels for one or more of the constituents in Appendix III at a monitoring well at the downgradient waste boundary, the regulations allow the facility an opportunity to complete an alternative source demonstration (ASD) showing that a source other than the unit (*i.e.*, an alternative source) was the cause of the SSI. Section 257.94(e)(2). The regulations provide a similar opportunity whenever assessment monitoring results indicate that an SSL exceeding the GWPS has been detected at a downgradient well for any of the Appendix IV constituents. 40 CFR 257.95(g)(3). If a successful ASD for an SSL is not completed within 90 days, corrective action must be initiated.

²⁵ Ashtracker provides public access to industry-reported data from state and company records about groundwater contamination at coal ash dumps. It can be accessed at <https://www.ashtracker.org>.

²⁶ EPA–HQ–OLEM–2020–0107–0073.

²⁷ Database Results (Excel) 04–12–12 at <https://archive.epa.gov/epawaste/nonhaz/industrial/special/fossil/web/html/index-3.html> and Summary Table for Impoundment Reports (.xls)—July 31, 2014, at <https://archive.epa.gov/epawaste/nonhaz/industrial/special/fossil/web/html/index-4.html>. Available at EPA–HQ–OLEM–2020–0107–0003.

²⁸ U.S. EPA. 2014. “Human and Ecological Risk Assessment of Coal Combustion Residuals.” RIN 2050–AE81. Office of Solid Waste and Emergency Response. Washington, DC. December. Docket ID No. EPA–HQ–RCRA–2009–0640–11993.

²⁹ <https://www.eia.gov/electricity/data/eia860m/>.

³⁰ In December 2016, the Water Infrastructure Improvements for the Nation (WIIN) Act gave EPA enforcement authority under RCRA sections 3007 and 3008 for the CCR regulations. See RCRA section 4005(d).

Specifically, EPA found in reviewing groundwater monitoring and corrective action reports that 42 ASDs or assessments of corrective measures (ACMs) concluded that a federally unregulated CCR source was responsible for the SSI or SSL. In Unit IV.B.2.b and c of this preamble are several examples (*i.e.*, damage cases) where owners or operators of CCR facilities claimed that an SSI or SSL is attributable to a CCR source rather than the federally regulated CCR unit.

In addition to reviewing the groundwater monitoring and corrective action reports, EPA also reviewed the history of construction reports, closure plans and reports, and fugitive dust control plans for facilities with CCR websites from 2018, 2019, 2020, and 2021. These documents contained either site maps, which identified currently regulated units, and in some cases, inactive or closed units at the facility, or narrative discussions of the site history, which included identification of where CCR were previously disposed or managed at the facility. Through this review, EPA found 65 references to CCR that are managed or disposed outside federally regulated CCR units; however, EPA was not able to find additional information about these units including whether groundwater monitoring has been conducted.

Given the available data about CCR facilities, the Agency reviewed the records for evidence of inactive landfills at active CCR facilities and inactive CCR facilities. EPA reviewed the available data and found clear, written documentation of about 34 inactive or closed CCR landfills at 22 CCR facilities. In addition, EPA evaluated those verified inactive or closed CCR landfills and found evidence from ASD reviews that eight landfills were identified as contaminating groundwater. Some of the landfills are adjacent to a federally regulated CCR unit and some are below federally regulated CCR units but are not considered part of the regulated unit. This is the available information that the Agency has regarding inactive CCR landfills and EPA has no information to suggest a different situation regarding inactive CCR landfills.

After reviewing all of this information, EPA identified a total of 134 areas at 82 active facilities³¹ where CCR is being managed, but which remain exempt under existing federal CCR regulations. These areas include inactive CCR landfills, closed CCR

landfills, closed CCR surface impoundments, and other solid waste management areas of CCR. Through further investigation, EPA found 42 federally unregulated units with documentation that the units are potentially contaminating groundwater. Of those, EPA found evidence that eight were associated with closed CCR landfills, one related to an inactive CCR landfill, 22 pertained to closed CCR surface impoundments, three involved CCR disposed below the regulated CCR unit, and eight related to CCR disposed or managed in other solid waste management areas. A subset of examples of these 42 federally unregulated units are briefly summarized below; first for facilities that attributed an SSL associated with a federally regulated landfill or impoundment to the federally unregulated unit and second where SSIs are attributed to a federally unregulated unit. Although some of these units are being regulated or addressed by states, it does not negate the need to expand the federal CCR regulations to address contamination and potential risks from CCRMU across the nation.

b. Examples of CCRMU With Identified SSIs

Under the existing CCR regulations, when a facility determines there is an SSL for one or more Appendix IV constituents and completes a successful ASD showing that a source other than the regulated unit is the cause of the SSL(s), the facility is not required to initiate corrective action for that particular constituent. Through ASD reviews, EPA identified several areas at active facilities where CCR was managed outside of a regulated unit and was identified as a source of one or more Appendix IV SSL(s). The following facilities are examples of situations in which potential CCRMU have been identified as the source of an SSL and demonstrate the need to expand the federal CCR regulations as EPA is proposing in this preamble.

James H Campbell Power Plant, West Olive, Michigan

The JH Campbell Power Plant, owned and operated by Consumers Energy Company, is located within a mile of Lake Michigan. The facility has five regulated CCR units, including three CCR surface impoundments (Pond A, Bottom Ash Ponds 1–2, and Bottom Ash Pond 3) and two CCR landfills. The “wet ash ponds area” is approximately 267 acres and is bounded by perimeter dikes with a system of internal dikes separating the individual ash ponds. In addition to the five regulated CCR units,

there are at least seven other unregulated, unlined “closed” impoundments³² that ceased placement of waste prior to October 19, 2015, do not have an engineered cap nor vegetative cap, and have a closure plan that was approved by the State. Based on the groundwater monitoring report reviews, there were SSIs over background at many wells at all units and some had an SSL for arsenic and selenium. At Pond A, which closed with waste in place in 2019, there are SSIs for boron and sulfate, and SSLs were identified for arsenic (13 µg/L [MCL of 10 µg/L]) and selenium³³ (143 µg/L [MCL of 50 µg/L]) for which an assessment of corrective measures was completed, and the selected remedy is source removal and final cover as the primary corrective action. In the 2021 Annual Groundwater Monitoring and Corrective Action Report posted in January 2022, Consumers Energy concluded there was an ASD for Pond A and said, “Increases in Appendix III constituents (*e.g.*, boron) and direct exceedances of the selenium GWPS in JHC–MW–15011, JHC–MW–15010, JHC–MW–15009, and JHC–MW–15008R that have not yet resulted in a statistically significant exceedance suggest a detectable influence from the immediately adjacent, upgradient, closed, pre-existing CCR units on-site. The closed, preexisting units are not regulated under the RCRA CCR Rule, but remedial action is being taken under Consent Agreement WMRPD No. 115–01–2018. A [remedial action plan] for these units was submitted to [Michigan’s Department of Environment, Great Lakes, and Energy] on September 30, 2021.” During the 2021 groundwater monitoring period for Bottom Ash Ponds 1–2, which closed by removal in 2018, SSIs were identified for boron, calcium, chloride, pH, sulfate, and total dissolved solids (TDS); also, one SSL was identified for arsenic (38 µg/L [MCL of 10 µg/L]).³⁴ An assessment of corrective measures has been completed for the CCR unit and the primary selected remedy is source removal and final cover. Consumers Energy also said in the 2022 semiannual

³² These “closed” impoundments (Pond B, Pond C, Pond D, Pond F, Pond G (G1 and G2), Pond H, and Pond K) are listed in a figure on page 12 of the 2021 Annual Groundwater Monitoring and Corrective Action Report, JH Campbell Power Plant Pond A, January 2022, Prepared for Consumer’s Energy.

³³ JH Campbell Semiannual Progress Report—Selection of Remedy, Ponds 1–2 North and 1–2 South, and Pond A, July 30, 2022. Pages 3–4.

³⁴ Annual Groundwater Monitoring and Corrective Action Report, JH Campbell Power Plant Ponds 1–2 North and 1–2 South, January 2022, Prepared for Consumers Energy. Page 23.

³¹ This information can be found in the document titled “Potential CCR Management Units” in the docket for this action.

progress report that the facility is reevaluating the groundwater “monitoring system for [Bottom Ash] Ponds 1–2 to more accurately account for the influence from the closed, pre-existing units.”

New Castle Generating Station, Pennsylvania

GenOn Power Midwest LP (GenOn) operates the New Castle Generating Station located in West Pittsburg, Pennsylvania. The New Castle Generating Station has two CCR units subject to the regulations—an impoundment (North Bottom Ash Pond) and a landfill (New Castle Plant Ash Landfill). Each of these CCR units has relevance to this proposal due to other unregulated disposal units located adjacent to the regulated CCR units.

The North Bottom Ash Pond was used for the management of bottom ash until 2016 when the facility transitioned from coal to natural gas. After the transition to natural gas, GenOn initiated closure of the North Bottom Ash Pond by removing all waste from the impoundment. Closure of the impoundment was certified in 2019.³⁵ Groundwater monitoring associated with the impoundment while the unit was operating detected arsenic at SSL above the GWPS in all downgradient monitoring wells.³⁶ In accordance with the procedures in the regulations for CCR units in 40 CFR 257.94(e)(2), GenOn determined that an alternative source was responsible for these SSLs of arsenic. Specifically, the ASD found that a 120-acre unlined CCR surface impoundment located immediately adjacent to the North Bottom Ash Pond was responsible for the arsenic concentrations in the downgradient monitoring wells.³⁷ According to the 2019 Annual Report prepared by GenOn, there were SSLs for arsenic (0.087 mg/L [MCL of 10 µg/L]) in the downgradient monitoring wells.³⁸ Consequently, because the SSLs of arsenic were attributed to another source (*i.e.*, a former unlined CCR surface impoundment), GenOn concluded it was not required to remediate the arsenic contamination under the federal CCR regulations.

GenOn also determined that there were SSIs above background levels for multiple analytes at the New Castle Plant Ash Landfill (Ash Landfill), which

is the other regulated CCR unit at the New Castle Generating Station. In its most recent annual groundwater monitoring report in 2022, GenOn reported SSIs for boron, calcium, fluoride, sulfate, and total dissolved solids.³⁹ GenOn determined that an alternative source was responsible for these analyte increases, specifically pointing to an “underlying historic ash impoundment and other closed stages of the landfill.”⁴⁰ Prior to development of the 60-acre Ash Landfill, CCR was disposed in an impoundment from approximately 1939 to 1978.⁴¹ After the impoundment was dewatered in 1978, dry CCR was disposed in this area in several stages of CCR placement up until the time Ash Landfill began operation. Since 2018, GenOn has attributed SSIs for boron, calcium, fluoride, sulfate, and TDS to this historic disposal of CCR.

Huntington Power Plant, Utah

The Huntington Power Plant in Huntington, Utah is owned and operated by PacifiCorp and has one regulated unit, the Huntington CCR Landfill. While conducting the required groundwater monitoring for the Huntington CCR Landfill, there were SSIs for chromium, cobalt, lithium, molybdenum, selenium, fluoride, and arsenic, so the owner and operator conducted assessment of corrective measures. There is also a former combustion waste landfill called the Old Landfill, which is located northwest of the regulated Huntington CCR Landfill. The ACM report⁴² assumes the SSIs are the result of groundwater interactions with both the Huntington CCR Landfill and the Old Landfill. Both landfills have stormwater run-on from the area surrounding the landfill. This run-on is routed around the landfills via diversion ditches and run-off from the landfills itself is collected and retained in a sediment basin north of the Huntington CCR Landfill. The facility is implementing a remedy to address releases only from the regulated CCR Huntington Landfill, but the remedy selection report⁴³ does not appear to address releases from the Old Landfill.

J.B. Sims, Grand Haven, Michigan

The J.B. Sims Generating Station, owned and operated by Grand Haven Board of Light and Power, is located on Harbor Island, north of Grand Haven, Michigan. Harbor Island is bound to the north, east, and west by the Grand River and to the south by the South Channel, tributaries of Lake Michigan. The facility has two federally regulated CCR units (Unit 1 & 2 and Unit 3), both of which are inactive, unlined surface impoundments. Unit 1 & 2 is approximately 1.2 acres and includes areas where, prior to October 19, 2015, CCR was placed in unlined impoundments and used as fill in low-lying areas of adjacent wetlands. Unit 3 is approximately 0.5 acres and was built on top of historically placed CCR. The boundary of Unit 1 & 2 was updated in an agreement with EPA and the State in January 2021,⁴⁴ to include an area that received CCR prior to 1978. Therefore, the groundwater monitoring network and closure plan are currently being updated to reflect the new boundary and better address contamination from historical CCR across the units.⁴⁵ Additionally, in March 2022, the State issued an enforcement notice⁴⁶ to J.B. Sims citing inadequate groundwater monitoring and failure to address all areas where CCR were managed (*e.g.*, stored, placed) prior to disposal during the unit's operation. As such, the facility is considering expanding Unit 3's groundwater monitoring network. The units are often partially flooded, and groundwater elevations and flow direction are influenced by precipitation and water levels in the Grand River and the South Channel.

Based on groundwater monitoring report reviews, both units have had SSIs and SSLs since groundwater monitoring was initiated in 2017. During 2021, both Unit 1 & 2 and Unit 3 had SSIs for all Appendix III constituents and SSLs for arsenic (98 µg/L [MCL is 10 µg/L]), chromium (270 µg/L [MCL is 100 µg/L]), cobalt (22 µg/L [GWPS is 6 µg/L]), fluoride (13 mg/L [MCL is 4 mg/L]), and

⁴⁴ The meeting between Grand Haven Board of Light and Power, the state, and EPA during which the new boundaries for Unit 1 & 2 were agreed to is discussed on page 3 (PDF page 10) of the 2021 Annual Groundwater Monitoring & Corrective Action Report by Golder Associates. January 28, 2022.

⁴⁵ Letter to Grand Haven Board of Light and Power—Update To The October 14, 2019 J.B. Sims Generating Station Inactive Units 1/2 Impoundment And Unit 3 Closure Plan—Interim Conditions For Closure. October 22, 2021.

⁴⁶ The State of Michigan, Department of Environment, Great Lakes, and Energy (EGLE) issued an enforcement notice via email March 22, 2022, to Grand Haven Board of Light and Power, J.B. Sims.

³⁵ CCR Compliance, Closure Certification Report, Closure by Removal, New Castle North Bottom Ash Pond. June 2019.

³⁶ *Id.* At 5.

³⁷ *Id.*

³⁸ CCR Compliance, Groundwater Monitoring and Corrective Action Annual Report, New Castle North Ash Pond and Ash Landfill. January 2020.

³⁹ CCR Compliance, Groundwater Monitoring and Corrective Action Annual Report, New Castle Ash Landfill. December 2022.

⁴⁰ *Id.* At 3.

⁴¹ New Castle Plant Ash Landfill—Annual CCR Unit Inspection Report. January 16, 2018.

⁴² Corrective Measures Assessment CCR Landfill—Huntington Power Plant Huntington, Utah. May 2019.

⁴³ Remedy Selection Report CCR Landfill—Huntington Power Plant, Huntington, Utah. August 2020.

lithium (2800 µg/L [site-specific GWPS is 59 µg/L]).⁴⁷ In December 2020, J.B. Sims submitted an ASD for Unit 3's 2019 SSLs for chromium, cobalt, fluoride, lead, and lithium, pointing to the historic fill across the island as the source of the SSLs.^{48, 49} Furthermore, the Fourth Quarterly 2021 Monitoring Report suggested the continued SSIs and SSLs at Unit 3 were due to historical CCR fill beneath the unit, historical fill outside of Unit 1 & 2, and waste historically placed across the site.⁵⁰ However, until the groundwater monitoring networks are finalized, the extent of groundwater contamination and the source of all contamination cannot be determined. The assessment of corrective measures for both units began in February 2019 and is ongoing, pending finalization of the groundwater monitoring networks. Based on groundwater monitoring reports, EPA has found that due to the fluctuations in groundwater elevations in response to precipitation and nearby surface water levels, portions of the facility, including Unit 1 & 2, can be inundated or partially in contact with groundwater.

c. Examples of CCRMU With Identified SSIs

Under the existing CCR regulations, when a facility determines there is an SSI for one or more Appendix III constituents and completes a successful ASD showing that a source other than the regulated unit is the cause of the SSI(s), the facility is not required to initiate assessment monitoring for that particular constituent. 40 CFR 257.94(e). Through ASD reviews, EPA identified several areas at active facilities where CCR was managed outside of a regulated unit and was identified as a source of one or more Appendix III SSI(s). As such, any groundwater contamination from these potential CCRMU have not been investigated under the existing federal CCR regulations. The following facilities are examples of situations in

which potential CCRMU have been identified as the source of an SSI and demonstrate the need to expand the federal CCR regulations as EPA is proposing in this preamble.

Reid Gardner Generating Station, Moapa Valley, Nevada

Reid Gardner Generating Station, owned and operated by NV Energy, is located adjacent to the Muddy River and the Moapa Band of Paiutes reservation, approximately 45 miles northeast of Las Vegas. Reid Gardner has seven regulated CCR units: four unlined inactive surface impoundments (Pond 4B–1, Pond 4B–2, Pond 4B–3, and Pond E–1), two active unlined surface impoundments (Pond M–5 and Pond M–7), and one partially lined landfill (Mesa Landfill). The inactive surface impoundments covered 47 acres and were closed by removal in 2017.⁵¹ The inactive surface impoundments were constructed in 2003 (Pond E–1) and 2006 (Pond 4B–1, Pond 4B–2, and Pond 4B–3) to replace four of the eleven historical unlined evaporation ponds located at the facility that made up the evaporation pond complex (Pond 4A, Pond 4B–1, Pond 4B–2, Pond 4B–3, Pond 4C–1, Pond 4C–2, Pond D, Pond E–1, Pond E–2, Pond F, and Pond G).⁵² The evaporation pond complex was built within the Muddy River floodplain and used from approximately 1974 until approximately 2002 to evaporate CCR and other process wastewaters from the facility. The two active surface impoundments (Ponds M–5 and M–7) were constructed in 2010 approximately 0.75 miles south of the historical evaporation ponds and cover 28 acres. Mesa Landfill was constructed and operational prior to the 2015 CCR Rule and has a surface area of roughly 252 acres.

Based on groundwater monitoring report reviews, the inactive surface impoundments had no Appendix III SSIs above their established background concentrations during the detection monitoring event in 2019.^{53 54 55 56 57 58}

However, the inactive surface impoundments did have Appendix IV constituent concentrations above the standard GWPS, including arsenic (2.52 mg/L [MCL is 0.01 mg/L]), cadmium (0.0072 mg/L [MCL is 0.005 mg/L]), cobalt (242 µg/L [standard GWPS is 6 µg/L]), fluoride (35.4 mg/L [MCL is 4.0 mg/L]), lithium (27,300 µg/L [standard GWPS is 40 µg/L]), molybdenum (6,390 µg/L [standard GWPS is 100 µg/L]), selenium (0.204 mg/L [MCL is 0.05 mg/L]), thallium (0.026 mg/L [MCL is 0.002 mg/L]), and radium 226 & 228 combined (8.02 pCi/L [MCL is 5 pCi/L]). Ponds M–5 and M–7 and the Mesa Landfill have had SSIs for fluoride every year of detection monitoring for which ASDs have been performed pointing to natural variation in groundwater quality.^{59 60 61 62 63 64} ASDs were also performed for SSIs at Mesa Landfill for pH (2019 and 2021) and turbidity (2020 and 2021) that attributed the SSIs to natural variation in groundwater quality. Therefore, since ASDs have been performed for all SSIs and the

Corrective Action Report and Alternate Source Demonstration. January 31, 2020.

⁵⁶ Reid Gardner Generating Station Mesa Impoundments M5 and M7 Coal Combustion Residual 2020 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 29, 2021.

⁵⁷ Reid Gardner Generating Station Mesa Impoundments M5 and M7 Coal Combustion Residual 2021 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 28, 2022.

⁵⁸ Alternate Source Demonstration and Addendum to the Coal Combustion Residual 2017 Annual Groundwater Monitoring and Corrective Action Report Reid Gardner Generating Station Mesa CCR Surface Impoundments (Ponds M5 and M7). Prepared for NV Energy. April 13, 2018.

⁵⁹ Reid Gardner Generating Station Mesa Landfill Coal Combustion Residual 2018 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 31, 2019.

⁶⁰ Reid Gardner Generating Station Mesa Impoundments M5 and M7 Coal Combustion Residual 2018 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 31, 2019.

⁶¹ Reid Gardner Generating Station Mesa Landfill Coal Combustion Residual 2019 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 31, 2020.

⁶² Reid Gardner Generating Station Mesa Landfill Coal Combustion Residual 2020 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 31, 2021.

⁶³ Reid Gardner Generating Station Mesa Landfill Coal Combustion Residual 2021 Annual Groundwater Monitoring and Corrective Action Report and Alternate Source Demonstration. January 28, 2022.

⁶⁴ Alternate Source Demonstration and Addendum to the Coal Combustion Residual 2017 Annual Groundwater Monitoring and Corrective Action Report Reid Gardner Generating Station Mesa Landfill. Prepared for NV Energy. April 13, 2018.

⁴⁷ SSL concentrations can be found in Appendix B (PDF page 512) of the 2021 Groundwater Monitoring & Corrective Action Report prepared by Golder Associates on behalf of Grand Haven.

⁴⁸ 2020 Alternate Source Demonstration J.B. Sims Generating Station—Unit 3 Impoundments Submitted to: Grand Haven Board of Light and Power Submitted by Golder Associates Inc. December 28, 2020.

⁴⁹ Technical Memorandum to Michigan Department of Environment, Great Lakes, and Energy—Unit 3 Impoundments Alternate Source Demonstration Response Grand Haven Board of Light And Power—JB Sims Power Generating Station. February 12, 2020.

⁵⁰ Memorandum to Michigan Department of Environment, Great Lakes, and Energy—Fourth Quarter 2021 Monitoring Report, Former JB Sims Generating Station, Unit 3 A&B Impoundments—Response to Comments. March 8, 2022.

⁵¹ Reid Gardner Generating Station Inactive Coal Combustion Residual Surface Impoundments Ponds 4B–1, 4B–2, 4B–3, and E–1 Closure Certification, April 2019.

⁵² Construction History, Pond E1, Reid Gardner Generating Station. April 11, 2018.

⁵³ Reid Gardner Generating Station Inactive CCR Surface Impoundment E–1. Coal Combustion Residual 209 Annual Groundwater Monitoring and Corrective Action Report. July 31, 2019.

⁵⁴ Reid Gardner Generating Station Inactive CCR Surface Impoundments 4B–1, 4B–2, and 4B–3. Coal Combustion Residual 2019 Annual Groundwater Monitoring and Corrective Action Report. Revision 1. May 14, 2020.

⁵⁵ Reid Gardner Generating Station Mesa Impoundments M5 and M7 Coal Combustion Residual 2019 Annual Groundwater Monitoring and

active units, Reid Gardner has not moved from detection monitoring to assessment monitoring. The facility also claims the historical, co-located evaporation ponds are the source of groundwater contamination in the area and not the CCR-regulated units. Specifically, in the closure certification for the inactive surface impoundments, the facility points to documentation as far back as the 1980s that describe seepage from Pond D, the historical Pond E-1 and E-2, Pond F, and Pond G and leakage at an estimated rate of 50 acre-feet/year from Ponds 4C-1 and 4C-2 and historical Ponds 4B-1, 4B-2, and 4B-3.

Cooper Station, Somerset, Kentucky

Cooper Station is owned and operated by East Kentucky Power Cooperative (EKPC) and is located in Somerset, Kentucky. There is one CCR landfill on-site, and the disposal area covers 96.32 acres in a total State-permitted area of 315.25 acres. Before construction of the landfill, CCR was managed in an unlined surface impoundment below the current landfill location. The facility conducted an ASD in 2018 for boron, calcium, sulfate, and TDS.⁶⁵ Previous analyses indicate that karst regions under the historic impoundment may have facilitated the release of some contamination. ASD results indicate the regulated CCR landfill is not the source of the release since it is lined but did not definitively state if the facility determined the unregulated unlined surface impoundment beneath the landfill as the alternative source. As such, the facility determined that the current CCR landfill remains in detection monitoring.

Seminole Electric Cooperative, Florida

Seminole Electric Cooperative (Seminole) operates the Seminole Generating Station located in Palatka, Florida. For CCR that is not beneficially used, CCR is disposed at the facility in a landfill (Increment One Landfill), which is subject to the CCR regulations. This CCR landfill is a double-lined landfill with a leachate collection system and, because part of the Increment One Landfill overlaps with the side-slope of a former, federally unregulated landfill, the liner system also includes a high-density polyethylene geomembrane where the two units interface.⁶⁶ Seminole

determined there were SSIs above background levels for multiple analytes in one or more monitoring wells at the downgradient waste boundary in 2018, including SSIs for boron, calcium, chloride, sulfate, and TDS. Seminole determined that one or more alternative sources were responsible for these analyte increases. These sources include former test cells (*i.e.*, areas where CCR was placed in the 1980s for purposes of construction evaluations that are now located beneath the Increment One Landfill), a former CCR landfill adjacent to the Increment One Landfill, and several process water ponds next to the Increment One Landfill.⁶⁷ Since 2018, Seminole has attributed SSIs for these analytes to these alternative sources and therefore, has not moved from detection monitoring to assessment monitoring.

R.M. Schahfer Generating Station, Indiana

The R.M. Schahfer Generating Station, owned and operated by Northern Indiana Public Service Company, LLC (NIPSCO), has several CCR units subject to the regulations, including several CCR impoundments and a CCR landfill consisting of multiple cells or phases of operation ("Landfill"). The Landfill is of particular relevance to this proposal because includes three cells subject to federal CCR regulations (Phases V through VII) and four landfill cells that are not (Phases I through IV). In the course of conducting the required groundwater monitoring for the regulated cells of the Landfill, in January 2018, NIPSCO determined that there were SSIs above background levels for all seven analytes in Appendix III at one or more monitoring wells at the downgradient waste boundary of the regulated CCR units. This included SSIs for boron, calcium, chloride, fluoride, pH, sulfate, and TDS.⁶⁸ Through procedures laid out in the regulations for regulated CCR units in 40 CFR 257.94(e)(2), NIPSCO determined that these groundwater SSI impacts were not due to a release from the regulated CCR landfill cells, but instead were attributable to another source. Specifically, NIPSCO has concluded that "a release from the non-regulated, unlined portions of the landfill, Phases 1 and II, is the source of the identified SSIs."⁶⁹ Subsequent groundwater

monitoring of the regulated Landfill cells since 2018 continues to identify SSIs and NIPSCO continues to attribute those impacts to releases from the unregulated Phase I and II cells.⁷⁰

Landfill Phase I is a 20-acre unlined cell that received CCR (flue gas desulfurization materials and fly ash) between 1984 and 1991 and subsequently closed with a final cover system in 1999. Phase II of the Landfill is an unlined 42-acre cell where flue gas desulfurization materials and fly ash were disposed between 1991 to 1998. The Phase II cell was closed with a final cover system in 1998. CCR landfills such as the Phase I and II cells are not regulated by the existing regulations because the cells have not received CCR on or after October 19, 2015. As a result, NIPSCO has not been required under the existing federal CCR regulations to investigate further and remediate as necessary groundwater impacts from the unlined Phase I and II cells.

Waukegan Generating Station, Illinois

An example of CCR used as fill on-site is Midwest Generation's Waukegan Generating Station in Waukegan, Illinois. There are two CCR surface impoundments named the East Ash Pond and West Ash Pond, which were used interchangeably during the facility's operational history and have a multi-unit groundwater monitoring system. The East Ash Pond has a surface area of 9.8 acres with a storage capacity of 184,000 cubic yards. The West Ash Pond has a surface area of 10 acres with a storage capacity of 223,000 cubic yards. According to the 2018 Annual Groundwater Monitoring and Corrective Action Report, there was detection of SSIs over background for Appendix III constituents, including pH and sulfate.⁷¹ An ASD was completed that claimed other potential historic sources were the cause of the SSIs. In the 2019 Annual Groundwater Monitoring and Corrective Action Report, an ASD for Appendix III constituents identified calcium and TDS with the same claim that other potential historic sources were the cause of the SSIs.⁷² The ASDs discuss that the downgradient

⁶⁵ Begins on PDF page 20 of the 2018 Annual Groundwater Monitoring and Corrective Action Report—Landfill Phase V and Phase VI. April 13, 2018.

⁷⁰ 2021 Annual Groundwater Monitoring and Corrective Action Report, Landfill Phase V, Phase VI, and Phase VII, NIPSCO LLC R.M. Schahfer Generating Station. January 31, 2022.

⁷¹ 2018 Waukegan Generating Station Annual GWMCA Report, Appendix B, PDF pg. 100. January 2019.

⁷² 2019 Waukegan Generating Station Annual GWMCA Report, Appendix B, PDF pg. 100. January 2020.

⁶⁵ Annual CCR Groundwater Monitoring & Corrective Action Report, Cooper Landfill, January 31, 2019. The ASD is discussed in Appendix C of the report.

⁶⁶ Seminole Generating Station Increment One Landfill Annual Groundwater Monitoring and Corrective Action Report. January 31, 2019.

⁶⁷ *Id.* at 20.

⁶⁸ 2018 Annual Groundwater Monitoring and Corrective Action Report—Landfill Phase V and Phase VI, NIPSCO R.M. Schahfer Generating Station. January 31, 2019.

⁶⁹ Northern Indiana Public Service Company, R.M. Schahfer Generating Station, Wheatfield, Indiana, Schahfer Landfill Phase V and Phase VI, Alternative Source Demonstration. April 13, 2018.

monitoring wells were installed within the berms for the surface impoundments that consisted of a “mixture of fill and beneficially reused coal combustion by-product”.^{73 74} The 2018 ASD also notes that an upgradient well, MW-05 which is not a part of the CCR groundwater monitoring network, has substantially higher sulfate and boron concentrations than the downgradient wells suggesting an upgradient source. Furthermore, the 2019 ASD mentions that the fluctuating TDS concentrations at downgradient well MW-16 are correlated to fluctuations in TDS at MW-05 further suggesting an upgradient source. While these ASDs suggest that the sources may be CCR within the berms and an upgradient source they do not analyze these potential sources to verify the claims. EPA did verify that the boring logs for groundwater monitoring wells MW-01 through MW-05 and MW-16 show they were installed within 11 to 20 feet of CCR in the berms surrounding the surface impoundments.⁷⁵ In addition, construction drawings in the history of construction show “existing fill” or CCR was used in the construction of the surface impoundment access ramps and underneath the surface impoundment liners.⁷⁶ The facility continued to use the ASDs for SSIs in 2020 and 2021, therefore, the surface impoundments remain in detection monitoring.

White Bluff Steam Electric Station, Arkansas

The White Bluff Steam Electric Station in Redfield, Arkansas is owned or operated by Entergy and has three CCR units: two CCR surface impoundments (A Recycle Pond/South Pond and B Recycle Pond/North Pond); and one CCR landfill (Existing CCR Landfill Cells 1–4). CCR previously was disposed in a 20-acre ravine,⁷⁷ which was closed and covered in accordance with the original facility State-issued

permit. The active landfill was then built on top of, and adjacent to, the unlined, closed landfill. In 2018, the facility conducted intrawell monitoring of the groundwater at the facility and SSIs for pH, calcium, TDS, and boron were detected. An ASD was completed and determined that the sources of the SSIs were: (1) Releases from portions of the Coal Ash Disposal Landfill (CADL) closed before the effective date of the CCR Rule (October 19, 2015); (2) Surface water that has come into contact with on-site CCR and has migrated into the subsurface; and/or (3) Natural variation in groundwater quality. Therefore, the landfill remains in detection monitoring.

3. Summary of CCR Management Unit Proposal

After considering all of the above data and information, EPA is proposing to establish a new category of regulated units that would be subject to a set of requirements tailored to the characteristics of such units and the risks that they present. EPA is proposing that this new category of units, called “CCR management units” or CCRMU, would consist of CCR surface impoundments and landfills that have closed prior to the effective date of the 2015 CCR Rule, inactive CCR landfills, and any area at a facility where solid waste management involving the past or present placement or receipt of CCR directly on the land has or is occurring.

Further, EPA is proposing to require facilities to conduct a facility evaluation to identify and delineate any CCRMU present at the facility and document the findings in a report. In addition, EPA is proposing to require the facility to ensure that all identified CCRMU comply with the existing requirements in part 257 for groundwater monitoring, corrective action, closure, and post-closure care requirements. These requirements are intended to address

the risks posed by any existing releases of CCR or CCR constituents to the groundwater, regardless of when the CCR was placed in the units and prevent future releases. Consistent with the existing CCR regulations, owners and operators of CCRMU would also be required to record compliance with these requirements in the facility’s operating record, notify the state of certain actions taken and decisions made, and maintain a publicly accessible website on the internet of compliance information. The other existing requirements in part 257 are not necessary for CCRMU. For example, since CCRMU do not contain sufficient liquids to create a hydraulic head or to otherwise cause the conditions that might lead to a structural failure, the structural stability requirements are unnecessary. Furthermore, EPA is proposing that CCRMU, like legacy CCR surface impoundments, must close, and for the same reasons that EPA described with respect to legacy CCR surface impoundments, the location restrictions and liner design criteria are also unnecessary. This proposal would apply to all CCRMU at active CCR facilities and at inactive facilities with one or more legacy CCR surface impoundments, regardless of how or when the CCR was placed in the CCRMU. All of these proposals are discussed in more detail in this Unit of the preamble.

Note that all deadlines herein are framed by reference to the effective date of the rule and have been proposed based on an effective date that is 6 months from publication of the final rule. The Agency has included a document in the docket for this rule that summarizes the proposed compliance deadlines.⁷⁸ EPA requests comment on the compliance deadlines and the feasibility to meet the proposed compliance timeframes for CCRMU.

TABLE 2—PROPOSED COMPLIANCE TIMEFRAMES FOR CCRMU IN MONTHS AFTER EFFECTIVE DATE OF THE FINAL RULE

Proposed compliance timeframes for CCRMU			
40 CFR Part 257, Subpart D requirement	Description of requirement to be completed	Proposed deadline (months after effective date of the final rule)	Notes
Internet Posting (§ 257.107)	Establish CCR website	0	Subsequent requirements: Facility Evaluation Report; all recordkeeping.
Facility Evaluation (§ 257.75)	Initiate the facility evaluation.	0	Subsequent requirements: Facility Evaluation Report.
Facility Evaluation Report (§ 257.75).	Complete the Facility Evaluation Report.	3	Prerequisite requirements: Facility Evaluation, Establish CCR website.

⁷³ 2020 Waukegan Generating Station Annual GWMCA Report. January 2021.

⁷⁴ 2021 Waukegan Generating Station Annual GWMCA Report. January 2022.

⁷⁵ Waukegan boring well logs.

⁷⁶ October 2016, Waukegan Generating Station History of Construction.

⁷⁷ Entergy Arkansas, LLC White Bluff Steam Electric Station Landfill Cells 1–4 2021 Annual

Groundwater Monitoring and Corrective Action Report. January 31, 2022.

⁷⁸ Docket item is titled Proposed Compliance Deadlines for Legacy CCR Surface Impoundments and CCR Management Units.

TABLE 2—PROPOSED COMPLIANCE TIMEFRAMES FOR CCRMU IN MONTHS AFTER EFFECTIVE DATE OF THE FINAL RULE—Continued

Proposed compliance timeframes for CCRMU			
40 CFR Part 257, Subpart D requirement	Description of requirement to be completed	Proposed deadline (months after effective date of the final rule)	Notes
GWMCA (§ 257.91)	Install the groundwater monitoring system.	6	Prerequisite requirements: Facility Evaluation Report. Subsequent requirements: Groundwater sampling and analysis program; Initiate detection and assessment monitoring; Annual GWMCA report.
GWMCA (§ 257.93)	Develop the groundwater sampling and analysis program.	6	Prerequisite requirements: Install groundwater monitoring system. Subsequent requirements: Initiate detection monitoring and assessment monitoring; Annual GWMCA report.
GWMCA (§ 257.90(e))	Annual GWMCA report	January 31 of the year following GWM system install.	Prerequisite requirements: Install groundwater monitoring system; Groundwater sampling and analysis plan.
Closure (§ 257.102)	Prepare written closure plan.	12	Subsequent requirements: Initiate closure.
Post-Closure Care (§ 257.104).	Prepare written post-closure care plan.	12	Prerequisite requirements: Written closure plan.
Closure and Post-Closure Care (§ 257.101).	Initiate closure	12	Prerequisite requirements: Written closure plan.
GWMCA (§§ 257.90–257.95)	Initiate the detection monitoring and assessment monitoring. Begin evaluating the groundwater monitoring data for SSI over background levels and SSL over GWPS.	24	Prerequisite requirements: Install groundwater monitoring system; Groundwater sampling and analysis plan.

4. Applicability and Definitions Related to CCR Management Units

EPA is proposing to amend § 257.50 by adding a new paragraph (j) to specify that subpart D applies to CCRMU. EPA is also proposing to add a new definition and revise 11 existing definitions in § 257.53 to implement the proposed criteria for CCRMU.

a. Definition of CCR Management Unit

EPA is proposing to define a *CCR management unit* to capture the solid waste management practices that have been demonstrated in the risk assessment and the damage cases to have the potential to contaminate groundwater. EPA is proposing to define a CCRMU as any area of land on which any non-containerized accumulations of CCR are received, placed, or otherwise managed, that is not a CCR unit. This definition is based on the current definitions of a CCR pile—which is currently regulated as a CCR landfill—and of a CCR surface impoundment, which both rely on the concept of “accumulations of CCR.” See, 40 CFR 257.53.

EPA is proposing that CCRMU would include historical solid waste management units such as CCR landfills and surface impoundments that closed under then-existing law prior to the effective date of the 2015 CCR Rule, as well as inactive CCR landfills (including

abandoned piles). It would also include any other areas where the solid waste management of CCR on the ground has occurred, such as structural fill sites, CCR placed below currently regulated CCR units, evaporation ponds, or secondary or tertiary finishing ponds that have not been properly cleaned up, and haul roads made of CCR if the use does not meet the definition of beneficial use. All of these examples involve the direct placement of CCR on the land, in sufficient quantities to raise concern about releases of hazardous constituents, and—in most, if not all cases—with no measures in place to effectively limit the contact between the CCR and liquids, and subsequent generation and release of any leachate.

EPA recognizes that this is a broad definition, but the Agency does not intend that the placement of any amount of CCR would necessarily constitute a CCRMU. Accordingly, EPA is proposing that the following would not be considered CCRMU: consistent with the current regulations, closed or inactive process water ponds, cooling water ponds, wastewater treatment ponds, and storm water holding ponds or aeration ponds. These units are not designed to hold an accumulation of CCR, and in fact, do not generally contain a significant amount of CCR. See, 80 FR 21357. In addition, consistent with the existing regulations,

neither an area or unit at which exclusively non-CCR waste is managed, nor any containerized CCR, such as a silo, would be considered CCRMU. See, Id. at 21356. Neither of these units present conditions that give rise to the risks modeled in EPA’s assessment or identified in the damage cases.

For similar reasons, the Agency is proposing that any CCR used in roadbed and associated embankments would not be considered CCRMU. As EPA explained in the 2015 rule the methods of application are sufficiently different from CCR landfills that EPA cannot extrapolate from the available risk information to determine whether these activities present similar risks. Roadways are subject to engineering specifications that generally specify CCR to be placed in a thin layer (e.g., six to 12 inches) under a road. The placement under the surface of the road limits the degree to which rainwater can influence the leaching of the CCR. There are also significant differences between the manner in which roadways and landfills can potentially impact groundwater. These include the nature of mixing in the media, the leaching patterns, and how input infiltration rates are generated. First, CCR landfills are typically a homogeneously mixed system, and as a result, there are no spatial variations of the chemical and physical properties of the media (for

example, bulk density, hydraulic conductivity and contaminant concentration). By contrast, roadways are generally constructed of several layers with different material properties (heterogeneity). This difference affects the hydraulic conductivity of a mass of CCR in a landfill, as compared to CCR placed in an embankment. Any potential leaching will tend to spread over the length of the embankment, as opposed to the leaching in a downward motion that would occur in a homogeneously filled landfill. Finally, EPA is concerned that groundwater monitoring of a road may not be practicable. However, even though EPA considers that the available information does not demonstrate that use in roadbed present sufficient risk to warrant the suite of requirements applicable to CCRMU, that calculus changes in the event the CCR in roadbed is contaminating groundwater. Accordingly, EPA is proposing that if a facility subsequently determines that the CCR in onsite roadbed is contributing to contamination to the aquifer, the facility would be required to address the contamination. For example, if during an on-going corrective action, a facility identifies the roadbed as an additional source of contamination, it would be required to address that contamination as part of the ongoing remediation of the aquifer. In addition, the measures EPA is proposing to require facilities to take would not be expected to identify truly de minimis quantities of CCR. As discussed in greater detail in the next section, EPA is proposing that facilities would only be required to identify accumulations if there are records to confirm the existence of CCRMU or visual evidence of CCR placement on the ground.

As a complement to this definition, EPA is proposing to define the term *inactive CCR landfill* to mean an area of land or an excavation that contains CCR but that no longer receives CCR on or after the effective date of this final rule and that is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine or a cave. For purposes of this subpart, this term also includes sand and gravel pits that received CCR, and abandoned CCR piles.

b. Revision to Definition of CCR Unit

EPA is proposing to modify the definition of *CCR unit* by stating that *CCR management units* are not covered by the definition of a *CCR unit*. See proposed regulatory text at § 257.53. Under the existing regulations, CCR

units are defined as CCR landfills and CCR surface impoundments, as well as any lateral expansion of a CCR landfill or CCR surface impoundment. In addition, the term *CCR unit* already covers inactive CCR surface impoundments at active facilities because these units are CCR surface impoundments. Similarly, because a *legacy CCR surface impoundment* is a CCR surface impoundment, these units are a *CCR unit* under the regulations.

As currently structured, many regulations specify that they apply collectively to the owners and operators of “*CCR units*,” rather than listing out each individual type of unit. As discussed elsewhere in this preamble, EPA is proposing to extend only a subset of the existing requirements in part 257, subpart D to CCRMU, consisting of requirements for groundwater monitoring, corrective action, closure, post-closure care, and reporting and recordkeeping. However, EPA is not proposing to apply the part 257 location restrictions, liner design criteria, structural integrity criteria for impoundments, and operating criteria to CCRMU. In order to implement this approach with the fewest revisions to the existing regulations, EPA is proposing to exclude CCRMU from the definition of *CCR unit* and propose specific modifications to those provisions that EPA intends would apply to CCRMU. To state another way, CCRMU would not be subject to provisions only applicable to *CCR units*.

c. Revisions to the Definitions of Owner and Operator

EPA is proposing revisions to the existing definitions of *Owner* and *Operator*. The existing definition of *Owner* is the “person(s) who owns a CCR unit or part of a CCR unit.” First, EPA is proposing to revise the definition to incorporate the concept of CCRMU into the existing definition because CCRMU are excluded from the definition of a CCR unit as discussed in the preceding Unit of the preamble. This would be accomplished by adding “or CCR management unit” to the existing definition. See proposed regulatory text at § 257.53. Second, the Agency is proposing to revise the definition of *Owner* to include the owner(s) of the entire facility, which would be achieved by adding “or a facility, whether in whole or in part” to the definition. EPA is not proposing to revise the definition of a “facility,” which under the existing regulations means “all contiguous land, and structures, other appurtenances, and improvements on land, used for treating, storing, disposing, or otherwise conducting solid waste management of

CCR. A facility may consist of several treatment, storage, or disposal operational units (e.g., one or more landfills, surface impoundments, or combinations of them).” 40 CFR 257.53.

EPA is proposing this revision in part to account for the more complicated ownership arrangements that exist at some utilities. EPA has found that there may be multiple owners at the same facility; for example, one entity may hold title to a single impoundment, while another entity may own the remaining disposal units at the site. Moreover, ownership can change over time, as individual units or portions of the facility are parceled off. This proposal would also more accurately reflect the nature of the obligations EPA is proposing to establish for CCRMU. For example, as discussed below, EPA is proposing to require an investigation of the entire disposal facility to identify CCRMU. At many sites, this would involve areas other than those encompassed by the definition of a CCR unit, extending to all areas where disposal or other solid waste management may be occurring. Moreover, relying exclusively on the “owner” of the CCRMU may be ambiguous in this context, as at some sites the owner may not yet be aware that a CCRMU is present (e.g., because it results from the historic placement or accumulation of CCR). EPA recognizes that this proposal would apply to currently regulated facilities, but it is not clear that this revision would actually amend the entities that currently are liable. EPA expects that most (if not all) utilities currently operate as though the regulation already required the owner operator of the facility to take actions; for example, under the existing regulations owners and operators are required to conduct corrective action even where the plume has migrated beyond the footprint of the regulated unit.

For similar reasons, EPA is proposing to revise the definition of *Operator* to incorporate the concept of CCRMU into the existing definition by adding “or CCR management unit” to the existing definition. See proposed regulatory text at § 257.53. In addition, the Agency is proposing revisions to account for the unique characteristics of a CCRMU. In cases where the CCRMU is closed (i.e., not receiving waste or otherwise in operation) or is a historic placement or accumulation of CCR, there will not be an entity that neatly fits the normal concept of an “operator,” because there would be no current or ongoing oversight or activity with respect to the continued use of the unit. To avoid any ambiguity, EPA is proposing to revise

the definition of “operator” to clarify that the term *Operator* includes those person(s) or parties responsible for disposal or otherwise actively engaged in solid waste management of CCR. It also includes those responsible for directing or overseeing groundwater monitoring, closure, or post-closure activities at a CCR unit or CCRMU.

Because multiple entities may potentially be liable, (owners and operators) EPA is providing the following guidance. Consistent with EPA’s typical practice, unless otherwise provided in the regulations, as long as one responsible entity (an owner or operator) has complied with the requirements, EPA will consider the obligation satisfied as to all potentially liable parties and will initially rely on owners and operators to determine among themselves how best to ensure compliance with the requirements.

d. Conforming Revisions to Other Existing Definitions

EPA is proposing revisions to eight definitions in § 257.53 to make reference to CCRMU. These definitions currently refer only to CCR units and the proposed changes would add the words “or CCR management unit” to the definitions so as to incorporate the concept of CCRMU into the existing definition. The eight definitions for which EPA is proposing this revision are: Active life or in operation, Active portion, Closed, CCR landfill or landfill, Qualified person, Qualified professional engineer, State Director, and Waste boundary. EPA is not proposing to otherwise revise or reopen the substance of the existing definitions as they apply to CCR units. Accordingly, the Agency will not respond to any comments on these definitions as they apply to CCR units.

5. Facility Evaluation for Identifying CCR Management Units

EPA is proposing that owners and operators of active or inactive facilities with one or more CCR unit(s) will need to conduct a facility evaluation. The purpose of the facility evaluation is to confirm whether any CCRMU exist on-site, and, if so, to delineate the lateral and vertical extent of the unit(s). In developing this proposal, EPA relied heavily on the RCRA subtitle C Facility Assessment process for identifying solid waste management units at a hazardous waste facility. In addition, EPA accounted for certain existing requirements in the CCR regulations; for example, under the 2015 CCR Rule, facilities were required to compile a history of construction for their existing impoundments. 40 CFR 257.73(c)(1).

Facilities were generally able to obtain all of the information specified in § 257.73(c)(1)(i) through (ix), even for units constructed decades ago. EPA expects that facilities will similarly be able to obtain the information that EPA is proposing would be required in the Facility Evaluation Report (discussed in Unit IV.B.5.b of this preamble).

EPA is proposing a two-step process for a facility evaluation. The first step would consist of a thorough review of available records in combination with a physical facility inspection and any necessary field work, such as soil sampling, to fill any data gaps from the information obtained from the review of available records. See proposed regulatory text at § 257.75(b). The second step of the facility evaluation would be to generate a Facility Evaluation Report to document the findings of the facility evaluation. See proposed regulatory text at § 257.75(c).

a. Facility Evaluation for CCR Management Units

EPA is proposing that during the facility evaluation the owner or operator of a CCR unit at an active facility or inactive facility would need to identify and delineate the extent, laterally and vertically, of any CCRMU at the facility. EPA is proposing a two-step process by which the facility would make those determinations: the first would be conducting a facility evaluation and the second would be the drafting of a Facility Evaluation Report. EPA is proposing that the deadline to initiate the facility evaluation would be no later than the effective date of the final rule in § 257.75(b).

A facility evaluation would begin with a review of all existing records and documents readily and reasonably available to or attainable by the facility, that contain information regarding any past and present CCR management that resulted in the accumulation of CCR on the ground. Consistent with the proposed definition of a CCRMU, in this context EPA considers the terms “placement” and “receipt” to include situations in which spilled or released CCR has been left on the ground. During this first step, the facility would be required to gather and review information to identify potential locations of CCR placement, and to determine preliminary boundaries and depths of any CCRMU. EPA is also proposing that a facility evaluation would include a physical inspection of the facility. Where necessary, the physical inspection would include field investigation activities, such as conducting exploratory soil borings, geophysical assessments, or any other

similar physical investigation confirmation activities to establish the location and boundaries of identified CCRMU, and to affirmatively rule out other areas of potential CCR placement at the facility that were identified during the information review. EPA is further proposing that the scope of the facility evaluation would be the entire facility as the term is currently defined in 40 CFR 257.53 and the evaluation would need to include all of the information specified in the CCRMU Facility Evaluation Report.

As noted, the facility evaluation would begin with a review of all readily and reasonably available information regarding past and present placement of CCR on the ground at the facility. In this first stage, the facility would need to gather all existing information that may be useful to determine any locations at the facility where CCR may have been placed (including spilled) on the ground. EPA expects that in this initial phase, the facility would cast a wide net, and collect all information that could potentially contain useful information to identify the potential locations of CCR placement at the facility. Finally, to complete the information review, the investigatory process would need to be documented, any data gaps identified, and plans for conducting a physical inspection of the site to verify locations, boundaries, and volumes of CCR placement at the facility would need to be formalized. Each step of this process is described in greater detail below.

i. Information Gathering

The first step in the facility evaluation process involves the collection of information that contains any information on whether CCR was either routinely and systematically placed on the ground, or where facility activities otherwise resulted in measurable accumulations of CCR on the ground. The quality and reliability of the information review will depend greatly on the owner’s and operator’s ability to collect relevant information. Information reviews may provide misleading results when significant sources of information are not considered. EPA is proposing that the information that must be gathered during this step would include any documents that contain information relevant to past facility operations and waste disposal processes. By the conclusion of the facility evaluation, EPA expects that the facility would be able to identify the date, locations, durations, and volumes or estimated quantities of CCR placement.

EPA expects that the amount of available written information and documentation that will be available for review during the document review phase may vary by facility. However, the following documents developed as part of complying with part 257, which are available to facilities, would normally contain information that can be useful in identifying CCRMU: inspection reports; history of construction reports; fugitive dust control plans; annual groundwater monitoring and corrective action reports; ASDs; ACM reports or other corrective action reports; and closure plans and reports. Further, there are other sources of readily available data that frequently contain information relevant to past facility operations and waste disposal processes, such as facility compliance reports produced for non-CCR programs (e.g., Toxic Substances Control Act [TSCA]/Occupational Safety and Health Administration [OSHA]/National Pollutant Discharge Elimination System [NPDES]/Clean Air Act [CAA]/Clean Water Act [CWA]); permits and permit applications, including NPDES, solid waste, dam safety, and air permits; historical and contemporary monitoring and reporting data, and facility operating logs and maps; and site imagery including available historical aerial photographs, site photographs, topographic maps, and/or engineering or construction drawings, including drawings for physical facility improvement projects, such as surface water control, water and power infrastructure and utilities, roads, berms, ponds and/or other physical features at the facility. EPA expects that facilities would search available records to determine whether they contain information relevant to the potential existence and locations of CCRMU.

EPA is further proposing to require that owners and operators gather information by conducting meetings and interviews with current or former facility personnel and any available state and local officials familiar with the facility to the extent that those persons are available and have knowledge about past and/or present facility operations. The goal of the interview process would be to help gather any information relevant to the facility operations and waste disposal processes. EPA's expectation is that a good faith effort be made to identify key individuals that may have direct knowledge of the facility's historic CCR management to fill in data gaps and/or verify existing information. The expectation is qualitative and dependent on the

reasonableness with which individuals can be identified and contacted. However, the purpose and process for determining the need for and the extent of employee interviews, or lack thereof, should be documented in the report. It is in the facility's best interest to evaluate historic management of CCR at the facility, identify CCR management units used throughout that duration, and, where gaps exist, try to identify individuals that may have information or direct knowledge regarding CCR management during those times. EPA expects that, when necessary, individuals involved in making decisions regarding CCR management during historic operations and/or implementing those decisions in the field would be able to be identified based on job titles and duties, time and duration of work service, and/or specific expertise using the facility's human resource records. Most government offices keep records of complaints, permits, and/or other correspondence that should be reviewed as part of the site evaluation. Individual officials in these records may be identified, particularly where they were involved with issues where CCR was managed or placed on the ground, or released to the environment through the air, surface water or groundwater.

It is estimated that the compliance cost associated with meeting and/or interviewing in-house personnel would be negligible for current employees, and minimal (less than 8 hours) for former employees since some effort may be involved with trying to locate and contact them. In addition to the cost for owners and operators to review state or local records for the facility during the facility evaluation, it is estimated that the cost associated with contacting any necessary state or local officials or offices would be minimal (less than 8 hours) since it is unlikely they would be the only source of information for CCR management activities at the facility, and their knowledge of any CCR management units may be limited.

ii. Information Evaluation

During this stage, EPA is proposing to require that a P.E. review the documents and information gathered during the initial step of review to draw conclusions regarding the existence of CCRMU at the facility. At the end of this stage, EPA expects the facility to identify: (1) Any areas where the facility can affirmatively conclude based on the available information that one or more CCRMU are present; and (2) Any areas where the available information indicates that CCR may have been either routinely and systematically placed on

the ground, or where facility activities otherwise could have resulted in measurable accumulations of CCR on the ground (*i.e.*, areas where the available information indicates that one or more CCRMU may be present).

Each of the information sources discussed above can provide valuable information that can be used to identify the existence and locations of CCRMU. Some specific examples are provided below:

Environmental reports for multimedia inspections contain useful information on site management practices, monitoring data, and unit conditions. These reports can also describe comprehensive monitoring evaluations at the site that can indicate where releases or areas of concern exist. Multimedia permit and permit applications contain large amounts of information on the facility design, waste management practices including how wastes were disposed of, and the physical characteristics of the surrounding area. These documents can contain old topographic maps, facility figures and drawings, wastestream flow diagrams, and unit and process descriptions.

If a groundwater monitoring report for a CCR unit indicates that contaminant levels in groundwater monitoring wells are the result of CCRMU rather than the monitored CCR unit, this would need to be further investigated during the facility evaluation process to fully delineate the locations of areas where CCR was placed on the ground, including the size of the unit and other related unit details.

Similarly, a review of aerial photographs can identify potential CCRMU at the facility at locations that have become overgrown or otherwise hidden over time. When used in conjunction with USGS topographic maps, owners and operators could look for evidence that may be indicative of placement of CCR on the ground. As an example, if aerial photographs and USGS topographic maps indicate the existence of a pond or dam system at the site, this may be enough to warrant further investigation of available documents and may require field investigation depending on the strength of information to determine if the changes were made to allow placement of CCR on the ground.

Finally, one of the primary purposes of the information review is to provide an understanding of the CCR management activities at the facility, allowing for subsequent observations during the physical site inspection to be focused to the greatest extent practical. While information obtained during the

review may be insufficient to support affirmative conclusions regarding the existence or non-existence of a CCRMU, based on the information available at most facilities, EPA expects that it will be possible to determine which areas at the facility would need to be inspected, and the type of data that would be needed to draw definitive conclusions. The Agency expects that all of the information gathered in the information review will be relevant to determining the areas to be inspected during the physical (visual) site inspection. Further, the information gathered during the information review would be used to support any necessary field activities.

iii. Physical Site Inspection

EPA is proposing to require that a facility conduct a physical site inspection of the entire facility in all cases. The purpose of the physical site inspection is to visually inspect the entire facility for evidence of CCR placement on the ground, ensure that all CCRMU have been identified, and fill any data gaps identified during the initial information evaluation. To that end, EPA is proposing that the physical site inspection must consist of a visual inspection of the entire facility to look for evidence that CCR is currently being managed on the ground. At a minimum, a facility would be required to visually inspect the site to confirm the information obtained from the information review phase and to identify any anomalies that warrant further investigation, such as an unnatural topographic rise or depression or an area where unspecified liquid waste was applied over several years. In addition, EPA is proposing that the facility would be required to conduct any field work such as soil sampling necessary to determine whether areas that had been identified as a potential CCRMU in fact contain CCR and to obtain the information required for the Facility Evaluation Report.

The complexity of past and current facility operations, combined with the amount of data that was available for review during the information review phase would impact how extensive the facility inspection must be. For example, if facility records are sparse or contain data gaps, the Agency expects that the facility inspection would be more thorough than in situations where detailed records exist. However, even in situations where detailed facility records exist, the facility must still conduct a visual inspection to ensure that all CCRMU have been identified, even if those areas were not identified

in the initial document review. In addition, EPA expects that in most cases, a facility will need to conduct some sampling or other fieldwork in order to obtain all the information required for the Facility Evaluation Report. For example, even if the facility had as-built engineering drawings for an old landfill, EPA expects that in some cases the facility may still need to conduct some sampling to establish the lateral and vertical dimensions of the CCRMU. If, after conducting a thorough document review and a visual inspection, the facility has found no evidence of any CCRMU, no further testing or sampling would be required to conclude that there are no CCRMU present at the facility. EPA is not proposing to require facilities to conduct widespread site sampling to prove that no CCRMU exist on-site. All recorded observations and data gathered during the facility evaluation, including any conclusions regarding the status of each CCRMU at the facility, must be assembled and incorporated into a Facility Evaluation Report, which is described in detail below.

b. Facility Evaluation Report for CCR Management Units

After completing the first step of the facility evaluation process, EPA is proposing to require the owners and operators of active or inactive facilities with one or more CCR unit(s) to compile and place in the operating record information pertaining to every CCRMU located at the facility no later than 3 months after the effective date of the final rule at § 257.75(c). The Facility Evaluation Report must be posted to the facility's CCR publicly accessible internet site within 30 days of that date. In developing the list of items to be included in the Facility Evaluation Report, the Agency considered certain requirements from existing regulations for History of Construction reports that must be generated for existing CCR surface impoundments at § 257.73(c)(1) as well as other requirements necessary to provide additional information about each CCRMU at the facility. In addition, the Agency is proposing to require that the Facility Evaluation Report include a certification from a P.E. stating that the Facility Evaluation Report meets the requirements at § 257.75(c). See proposed regulatory text at § 257.75(d). Further, the Agency is proposing to require that the Facility Evaluation Report include a certification to be signed by the owner or operator or an authorized representative similar to the certification that is required at § 257.102(e) and § 257.102(f) for existing

units undergoing closure. See proposed regulatory text at § 257.75(e).

EPA is proposing that the Facility Evaluation Report must contain the following: (1) The name and address of the person(s) owning and operating the facility; the unit name associated with any CCR unit and CCRMU at the facility; and the identification number of each CCR unit and CCRMU if any have been assigned by the state; (2) The location of any CCRMU identified on the most recent U.S. Geological Survey (USGS) 7.5-minute or 15-minute topographic quadrangle map, or a topographic map of equivalent scale if a USGS map is not available, with the location of each CCR unit at the facility identified; (3) A statement of the purpose(s) for which each CCRMU at the facility is or was being used; (4) A description of the physical and engineering properties of the foundation and abutment materials on which each CCRMU is constructed; (5) A discussion of any known spills or releases of CCR from each CCRMU and whether or not the spills or releases were reported to state or federal agencies; (6) Any record or knowledge of structural instability of each CCRMU; (7) Any record or knowledge of groundwater contamination associated or potentially associated with each CCRMU; (8) Size of each CCRMU, including the general lateral and vertical dimensions and an estimate of the volume of waste contained within the unit; (9) Dates when each CCRMU first received CCR and when each CCRMU ceased receiving CCR; (10) Specification of all CCR wastes that have been managed in each CCRMU at the facility; (11) A narrative description, including any applicable engineering drawings or reports of any closure activities that have occurred; (12) A narrative that documents the nature and extent of field oversight activities and data reviewed as part of the facility evaluation process, and that lists all data and information that was reviewed indicating the absence or presence of CCRMU at the facility; and (13) Any supporting information used to identify and assess CCRMU at the facility, including but not limited to any construction diagrams, engineering drawings, permit documents, wastestream flow diagrams, aerial photographs, satellite images, historical facility maps, any field or analytical data, groundwater monitoring data or reports, inspection reports, documentation of interviews with current or former facility workers, and other documents or sources of information used to identify and assess CCRMU at the facility.

As stated above, the Agency is proposing that the Facility Evaluation Report include a certification to be signed by a P.E. and the owner or operator or an authorized representative. Owners and operators of active or inactive facilities with one or more CCR unit(s) that do not contain any CCRMU would need to complete and place in the operating record a certified Facility Evaluation Report documenting the steps taken during the facility evaluation to determine the absence of any CCRMU. The Facility Evaluation Report must be placed in the facility operating record (§ 257.105(f)(25)), submitted to the appropriate regulating entity (§ 257.106(f)(24)), and published on the facility's website (§ 257.107(f)(24)).

While these requirements apply to facilities with one or more CCR units, owners and operators are required to compile this information only to the extent available. EPA acknowledges that there may be certain information or data that may be unknown or lost. Therefore, in this proposed rule, EPA is using the phrase "to the extent available" and clarifying that the term requires the owner or operator to provide information in the Facility Evaluation Report only to the extent that such information is reasonably and readily available. EPA intends that facilities provide relevant information only if documentation exists. EPA does not expect owners or operators to provide anecdotal or speculative information regarding the presence or absence of CCRMU. However, if data gaps exist, owners or operators subject to this proposed rule may need to collect additional field data to fill the gaps.

As stated previously, most of the activity needed to complete the Facility Evaluation and Facility Evaluation Report consists of reviewing reports and other documentation that already exist as a consequence of complying with other provisions in part 257, such as the history of construction, site or unit inspection reports, aerial imagery, quality assurance reports, groundwater monitoring and corrective action reports, or historic boring log reviews (e.g., subsurface investigations, geotechnical studies). Therefore, EPA estimates the hiring and onboarding of a contractor, data compilation, data review, conducting a site inspection, data analyses, and generation of a P.E.-certified report will take a total of 8 to 12 weeks or 2 to 3 months. See Unit IV.A.2.d. Where new analyses are needed (e.g., sampling to establish the dimension of a CCRMU), they are assumed to be minor with data inputs for performing these analyses existing

and readily available and capable of being conducted concurrently with some of the data review and report generation. Therefore, EPA believes the proposed deadline for the completion of the Facility Evaluation Report of no later than 3 months after the effective date of the final rule will be sufficient for the completion of these activities.

6. Applicable Existing CCR Requirements for CCR Management Units and Compliance Deadlines

a. Fugitive Dust Requirements for CCR Management Units

The air criteria in the existing regulations address the pollution caused by windblown dust, by requiring the owners and operators of CCR units to minimize CCR from becoming airborne at the facility. 40 CFR 257.80. These requirements apply to the entire facility, which means that the owner or operator is to minimize CCR fugitive dust originating not only from the CCR unit, but also from roads and other CCR management and material handling activities at the facility. Consequently, under this proposal, CCRMU would already be covered by the fugitive dust requirements in § 257.80 because CCRMU are located at facilities with a CCR unit. EPA is therefore only proposing to make those changes to the fugitive dust requirements in § 257.80 that are necessary to make clear that these requirements also apply to CCRMU. Specifically, EPA is to add "CCRMU" to the list of units subject to the requirements under § 257.80 and associated provisions under §§ 257.105 through 257.107. EPA solicits comments on amending § 257.80(b)(6) to include a deadline for facilities to amend the fugitive dust control plan no later than 30 days following a triggering event, such as the closure of a CCRMU or change in facility or CCR unit operations.

b. Groundwater Monitoring and Corrective Action Requirements for CCR Management Units

The existing groundwater monitoring criteria in §§ 257.90 through 257.95 require an owner or operator of a CCR unit to install a system of monitoring wells and specify procedures for sampling these wells. Further, it sets forth methods for analyzing the groundwater data collected to detect hazardous constituents (e.g., toxic metals) and other monitoring parameters in Appendix III or IV (e.g., pH, TDS) released from the units. 40 CFR 257.93. Once a groundwater monitoring system and groundwater monitoring program has been

established for a CCR unit the owner or operator must conduct groundwater monitoring and, if the monitoring demonstrates an exceedance of the groundwater protection standards for identified constituents in Appendix IV of part 257, corrective action is required. These requirements apply throughout the active life and post-closure care period of the CCR unit. EPA is proposing that the same groundwater monitoring and corrective action requirements that EPA is proposing to establish for legacy CCR surface impoundments would apply to CCRMU.

The existing groundwater monitoring and corrective action requirements in §§ 257.90 through 257.98 are essentially the same requirements that have been applied to both hazardous waste and municipal solid waste disposal units for decades, and with the exception of the one revision that EPA is proposing for legacy CCR surface impoundments, there is nothing about CCRMU that makes them distinct enough to warrant separate requirements. Each of the individual requirements are discussed in greater detail below.

i. Design and Installation of the Groundwater Monitoring System for CCR Management Units

EPA is proposing that owners and operators of CCRMU install the groundwater monitoring system as required by § 257.91 no later than 6 months from the effective date of the rule. See proposed regulatory text at § 257.90(b)(3)(i). The rationale for this compliance date is described in Unit IV.A.2.f.i of this preamble.

ii. Development of the Groundwater Sampling and Analysis Plan for CCR Management Units

EPA is proposing to require that owners and operators of CCRMU comply with the existing groundwater sampling and analysis program requirements for CCR units, including the selection of the statistical procedures, that will be used for evaluating groundwater monitoring data. 40 CFR 257.93 and 257.91(d)(3). See, proposed regulatory text at § 257.90(b)(3)(ii). EPA is proposing this requirement to be completed no later than 6 months after the effective date of the final rule. The rationale for this compliance date is described in Unit IV.A.2.f.ii of this preamble.

iii. Detection Monitoring Program and Assessment Monitoring Program Combined

EPA is proposing to require that facilities simultaneously initiate sampling and analysis of all Appendix

III and IV constituents at CCRMU to expedite the detection and cleanup of contamination from these abandoned unlined impoundments. This is the only revision to the existing groundwater monitoring requirements in §§ 257.90 through 257.95 that EPA is proposing to make for CCRMU.

As laid out in Unit IV.B.1, there is good reason to believe that CCRMU are currently contaminating groundwater. And as is the case with legacy CCR surface impoundments, at sites where the unit has potentially been leaking for a long time, the need to protect human health and environment by quickly detecting the constituents of concern in Appendix IV warrants expediting any necessary corrective action. See, *USWAG* 901 F.3d at 427–30. The rationale for this proposal is further explained in Unit IV.A.2.f.iii of this preamble.

iv. Collection and Analyses of Eight Independent Samples for CCR Management Units

EPA is proposing that no later than 24 months after the effective date of the final rule, owners or operators of CCRMU initiate the detection monitoring program by completing sampling and analysis of a minimum of eight independent samples for each background and downgradient well, as required by § 257.94(b). See proposed regulatory text at § 257.100(f)(4)(iii). Within 90 days after that, they must identify any SSIs over background levels for the constituents listed in Appendix III of this part, as required by § 257.94. EPA is also proposing that by this same deadline they initiate the assessment monitoring program by establishing groundwater protection standards and beginning the evaluation of the groundwater monitoring data for statistically significant levels over groundwater protection standards for the constituents listed in Appendix IV of this part as required by § 257.95. Then, if a statistically significant level over a groundwater protection standard for any of the constituents listed in Appendix IV of this part is found, the owner or operator of the legacy CCR surface impoundment must perform any required corrective action in accordance with §§ 257.96 through 257.98. The rationales for these deadlines are explained in Unit IV.A.2.f.iv. of this preamble.

v. Preparation of Initial Groundwater Monitoring and Corrective Action Report for CCR Management Units

EPA is proposing to apply the existing requirements in § 257.90(e) for preparation of an annual groundwater

monitoring and corrective action report to CCRMU and that owners and operators of CCRMU comply no later than January 31 of the year following the calendar year a groundwater monitoring system has been established for such CCR management unit, and annually thereafter. See proposed regulatory text at § 257.90(e)(1). The rationale for the components of this report and the expedited compliance deadline is explained in Unit IV.A.2.f.v of this preamble.

c. Closure and Post-Closure Care Criteria for CCR Management Units

EPA is proposing to apply the existing closure criteria for CCR surface impoundments in §§ 257.101 and 257.102 to CCRMU. EPA is also proposing to require that all CCRMU initiate closure, whether or not they are currently contaminating groundwater. Consistent with the proposal for legacy CCR surface impoundments, EPA is proposing to explicitly state that the alternative closure provisions in § 257.103 would not be applicable to CCRMU. Finally, EPA is proposing to apply the existing post-closure care requirements in § 257.104 to CCRMU. Each of these proposals are discussed in detail below

i. Criteria for Conducting Closure of CCRMU and Requirement To Close

Requiring the closure of CCRMU in accordance with §§ 257.101–257.102 would provide significant risk mitigation. As laid out in Unit IV.B.1 of this preamble, CCRMU at both inactive and active facilities pose significant risks to human health and the environment, at levels that are at least as significant as the risks presented by legacy CCR surface impoundments and the units currently regulated under the 2015 CCR Rule. Additionally, this is consistent with the existing CCR regulations, which require closure of all CCR units that have ceased receiving waste to mitigate the risks such units pose to human health and the environment. See, 40 CFR 257.102(e)(1). In particular, risks identified on a national scale are from releases of arsenic, lithium and molybdenum to groundwater. Available toxicological profiles indicate that ingestion of arsenic is linked to increased likelihood of cancer in the skin, liver, bladder and lungs, as well as nausea, vomiting, abnormal heart rhythm, and damage to blood vessels; ingestion of lithium is linked to neurological and psychiatric effects, decreased thyroid function, renal effects, cardiovascular effects, skin eruptions, and gastrointestinal effects; and ingestion of molybdenum is linked

to higher levels of uric acid in the blood, gout-like symptoms, and anemia. 80 FR 21451. To date, groundwater monitoring required by the 2015 CCR Rule has revealed that at least 40% of currently regulated surface impoundments and landfills have identified groundwater contamination and require corrective action to mitigate the associated risks. This number is expected to increase as more facilities come into full compliance with the rule. Another 23% of units have identified evidence of leakage and continue to monitor groundwater to ensure that contamination does not occur before the unit can be closed and source controls put in place. In many cases, CCRMU are historical landfills and surface impoundments. Thus, the relevant release pathways, exposure routes, and associated harm that can result are the same. As noted above, the risks associated with these CCRMU are anticipated to be at least as significant as the universe of currently operating units. There is further evidence that the risks may be even higher. This is a result of the fact that: (1) These units have been present onsite for longer and had more time to leak, and (2) Riskier disposal practices, such as co-management with coal refuse, were more common in the past. As the D.C. Circuit explained, RCRA requires EPA to set minimum criteria for sanitary landfills that *prevent* harm, not merely to ensure that contamination is remediated. See, *USWAG*, 901 F.3d at 430.

Further, EPA does not believe that any facility will need to continue to use a CCRMU. These units, by definition, are not currently receiving CCR; any unit currently receiving CCR is regulated under the existing regulations. Instead CCRMU have been “closed” by the facility, presumably in accordance with whatever state requirements were in effect at the time, or have been left inactive on-site. Because a continued need to use the disposal unit is a critical component of the alternative closure demonstrations (at § 257.103(f)), it appears that no CCRMU could qualify under the existing provisions. Accordingly, EPA does not believe these provisions are relevant to CCRMU.

While EPA is proposing that the CCR unit closure requirements would apply, EPA requests comment on other approaches to how a facility might implement the requirement to close at a site where the CCRMU lies beneath an operating unit. EPA also solicits comments on whether EPA should not mandate the closure of CCRMU. However, EPA is concerned that if CCRMU were not required to close, EPA

would not adequately address the risks from those units that have waste below the water table. In general, EPA considers that closure is the most certain way to adequately address the source of any releases from these units. Although EPA could rely upon the existing corrective action requirements to achieve source reduction, the Agency is concerned that this will not adequately prevent harm, as the statute requires, because these requirements would only apply upon a determination that the CCRMU has contaminated the aquifer. In addition, the closure requirements in § 257.102 provide a uniform approach that EPA is confident will adequately protect human health and the environment in all situations.

Given the locations of many CCRMU (located in floodplains, or wetlands, or near large surface water bodies), EPA is concerned that the base of these units may intersect with the groundwater beneath the unit. As EPA has previously explained, where the base of a surface impoundment intersects with groundwater, the facility will typically need to include engineering measures specifically to address any continued infiltration of groundwater into the impoundment in order to close with waste in place consistent with § 257.102(d). See, e.g., 87 FR 72989 (Nov 28, 2022), 85 FR 12456, 12464 (March 3, 2020). The same holds true for CCRMU that intersect with groundwater. The existing requirements in § 257.102(d)(1) and (3) apply to all CCR units and EPA is proposing that these provisions would also apply to CCRMU without revision. By contrast, the existing requirements in § 257.102(d)(2), which establish performance standards for drainage and stabilization of the unit, only apply to CCR surface impoundments. These performance standards are critical to ensuring that units that contain liquids are properly and safely closed, and therefore should apply to any unit, including a CCRMU and a CCR landfill, where the CCR remains saturated. Accordingly, EPA is proposing to revise § 257.102(d)(2) so that it applies to all CCR units and CCRMU. EPA provides a background discussion of the existing closure performance standards below. It is important to note that if there is no liquid in the unit, the proposed revision would not require the facility to do anything to meet the performance standards.

The CCR closure requirements applicable to closing with waste in place include general performance standards and specific technical standards that set forth individual engineering requirements related to the

drainage and stabilization of the waste and to the final cover system. The general performance standards and the technical standards complement each other, and both must be met at every site.

The specific technical standards related to the drainage of the waste in the impoundment require that, “free liquids must be eliminated by removing liquid wastes or solidifying the remaining wastes and waste residues.” 40 CFR 257.102(d)(2)(i). Free liquids are defined as all “liquids that readily separate from the solid portion of a waste under ambient temperature and pressure,” regardless of whether the source of the liquids is from sluiced water or groundwater. 40 CFR 257.53. Consequently, the directive applies to both the freestanding liquid in the impoundment and to all separable porewater in the impoundment, whether the porewater was derived from sluiced water, stormwater run-off, or groundwater that migrates into the impoundment. In situations where the waste in the unit is inundated with groundwater, the requirement to eliminate free liquids thus obligates the facility to take engineering measures necessary to ensure that the groundwater, along with the other free liquids, has been permanently removed from the unit prior to installing the final cover system. See, 40 CFR 257.102(d)(2)(i).

In addition to the process-specific technical requirements, all closures must meet the requirements in the general performance standard to “control, minimize or eliminate, to the maximum extent feasible,” both post-closure infiltration of liquids into the waste and releases of CCR or leachate out of the unit to the ground or surface waters, and to “preclude the probability of future impoundment of water, sediment, or slurry.” 40 CFR 257.102(d)(1)(i), (ii). EPA construes the word “infiltration” in this regulation as a general term that refers to the migration or movement of liquid into or through a CCR unit from any direction, including the top, sides, and bottom of the unit. This is consistent with the plain meaning of the term. For example, Merriam-Webster defines infiltration to mean “to pass into or through (a substance) by filtering or permeating” or “to cause (something, such as a liquid) to permeate something by penetrating its pores or interstices.” Similarly, the Cambridge English Dictionary defines infiltration as “the process of moving slowly into a substance, place, system, or organization,” and provides the following example “It is important to manage moisture infiltration into

buildings.” <https://dictionary.cambridge.org/us/dictionary/english/infiltration> (website visited 10/22/2022). None of these definitions limit the source or direction by which the infiltration occurs.

In situations where the groundwater intersects an unlined CCR unit, water may infiltrate into the unit from the sides and/or bottom of the unit because the base of the unit is below the water table. In this scenario, the CCR in the unit will be in continuous contact with water. This contact between the waste and groundwater provides a potential for waste constituents to be dissolved and to migrate out of (or away from) the closed unit. In such a case, the general performance standard also requires the facility to take measures, such as engineering controls, that will “control, minimize, or eliminate, to the maximum extent feasible, post-closure infiltration of liquids into the waste” as well as “post-closure releases to the groundwater” from the sides and bottom of the unit. 40 CFR 257.102(d)(1).

Whether any particular unit can meet these performance standards is a fact and site-specific determination that will depend on a number of considerations, such as the hydrogeology of the site, the design and construction of the unit, and the kinds of engineering measures implemented at the unit. Accordingly, the fact that prior to closure the base of a unit intersects with groundwater does not mean that the unit may not ultimately be able to meet the performance standards in § 257.102(d) for closure with waste in place. Depending on the site conditions, a facility may be able to meet these performance standards by demonstrating that a combination of engineering measures and site-specific circumstances will ensure that as a consequence of complying with the closure performance standards, the groundwater will no longer be in contact with the waste in the closed unit. As one example, where groundwater intersects with only a portion of an impoundment, the facility could close that portion of the unit by removing the CCR from that area of the unit but leaving waste in place in other areas. As another example, if the entire unit sits several feet deep within the water table, engineering controls can potentially be implemented to stop the continued flow of groundwater into and out of the waste. See, EPA Office of Solid Waste, Closure of Hazardous Waste Surface Impoundments, SW-873, p 81 (September 1982), Revised Edition.

Concerns have been raised that the existing regulations do not clearly support the above description. For

example, some have argued that the term “infiltration” only refers to the movement of water into a unit from the surface through a cover system, or that the regulations do not require facilities to eliminate “free liquids” derived from groundwater. Although EPA strongly disagrees and considers that the plain text of the regulation already clearly communicates the positions laid out above, the Agency requests comment on whether to revise the existing regulatory text so that it addresses the particular issues that regulated entities have raised. Specifically, as discussed previously EPA is requesting comments on whether to include a regulatory definition of the term “liquids,” which could specify that the term includes free water, porewater, standing water, and groundwater. Similarly, EPA requests comment on whether to adopt a regulatory definition of the term “infiltration,” consistent with term’s plain meaning and the dictionary definitions referenced above.

ii. Preparation of a Written Closure Plan for CCR Management Units

EPA is proposing that owners and operators of CCRMU comply with the existing requirements of § 257.102(b) requiring the preparation of a written closure plan. See proposed regulatory text at § 257.102(b)(2)(iii). EPA is proposing a deadline of 12 months after the effective date of the rule to complete the closure plan. The rationale for the components of this report and for this compliance date is described in Unit IV.A.2.g.ii of this preamble.

iii. Preparation of a Written Post-Closure Care Plan for CCR Management Units

EPA is proposing that owners and operators of CCRMU would be required to comply with the existing requirement in § 257.104(d) regarding the preparation of a written post-closure. See, proposed regulatory text at § 257.104(d)(4)(iii). EPA is proposing to require the post-closure care plan no later than 12 months after the effective date of the final rule. The rationale for the components of this report and for this compliance date is described in Unit IV.A.2.g.iii of this preamble.

iv. Deadline To Initiate Closure for CCR Management Units

EPA is proposing that owners and operators of CCRMU initiate closure no later than 12 months after the effective date of the final rule. See proposed regulatory text at § 257.101(f). EPA’s rationale for this timeframe is included in Unit IV.A.2.g.iv and Unit IV.A.2.a.ii of this preamble.

v. Deadline To Complete Closure for CCR Management Units

The existing CCR regulations currently require (at § 257.102(f)) an owner or operator of a CCR surface impoundment generally to complete closure activities within five years from initiating closure. The regulations also establish the conditions for extending this deadline, upon a showing that additional time is necessary.

EPA is proposing to apply the CCR surface impoundment closure timeframes because EPA has concluded that CCRMU closure will closely resemble CCR impoundment closures. First, as discussed in Unit IV.B.2.a, EPA identified a total of 134 areas where CCR is being managed, but which remain exempt under existing federal CCR regulations. Over half of these areas are associated with former, federally unregulated CCR surface impoundments. For those former impoundments that will be closed with waste in place, the owner or operator would need to procure substantial volumes of soil or borrow material to properly achieve the subgrade elevations needed to support the final cover system. For some CCRMU this material acquisition will involve the movement of tens of thousands of truckloads of soil or borrow material. This situation would also apply to certain CCR fill placements as well as to inactive CCR landfills where past waste disposal did not reach the landfill’s design capacity (*i.e.*, landfill airspace was not fully utilized). In these situations, EPA believes the timeframes to complete closure for existing CCR surface impoundments are more appropriate (*i.e.*, 5 years) than, for example the 6 months (and limited time extensions) provided for existing CCR landfills.

Second, EPA is finding through implementation of the existing regulations that a significant percentage of facilities are electing to close CCR units by removal of waste. If owners and operators of CCRMU were to similarly choose this approach to closure, a shorter timeframe would only be sufficient for smaller-sized CCRMU since removal operations often require tens of thousands of truckloads to relocate CCR to a suitable location.

Finally, as discussed in Unit IV.B.6, the Agency is concerned that the base of at least some CCRMU may intersect with the groundwater beneath the unit because CCRMU may be located in floodplains or wetlands, or near large surface water bodies. EPA’s experience in implementing the regulations is that such closures are generally more

complex and take longer to complete. This is because the facility will typically need to incorporate engineering measures into the closure activities to ensure that the groundwater will no longer be in contact with the waste in the unit. EPA thus believes the timeframes to complete closure of CCRMU should be the same as the timeframes provided for existing CCR surface impoundments.

In addition, EPA is proposing to make CCRMU eligible for limited time extensions to complete closure when justified by the owner or operator. EPA recognizes that there can be unforeseen and extraordinary circumstances that warrant additional time to close a CCRMU. For example, these circumstances can include climate of the location. Weather delays, and the need for coordination with and approvals from state regulatory agencies. Accordingly, the rule proposes to adopt the same procedures currently applicable to CCR surface impoundments, which would allow the owner or operator to obtain additional time to complete the closure of a CCRMU, provided the owner or operator can make the prescribed demonstrations. Consistent with the existing requirements for CCR surface impoundments, the amount of additional time that a facility could obtain would vary based on the size (using surface area acreage of the CCR unit as the surrogate of size) of the CCRMU. For CCRMU 40 acres or smaller, the maximum time extension is 2 years. For CCRMU greater than 40 acres, the maximum time extension is five 2-year extensions (10 years), and the owner or operator must substantiate the factual circumstances demonstrating the need for each 2-year extension. See proposed regulatory text at § 257.102(f)(2).

vi. Post-Closure Care for CCR Management Units

The existing post-closure care criteria require the monitoring and maintenance of units that have closed in place for at least 30 years after closure has been completed. 40 CFR 257.104. During this post-closure period, the facility would be required to continue groundwater monitoring and corrective action, where necessary. EPA is proposing to apply these existing requirements to CCRMU without revision. These criteria are essential to ensuring the long-term safety of CCRMU.

d. Recordkeeping, Notification and Internet Posting for CCR Management Units

As discussed in Unit IV.A.2.h of this preamble, the 2015 CCR Rule required at §§ 257.105 through 257.107 for owner or operators of CCR units to record certain information in the facility's operating record. In addition, owners and operators are required to provide notification to states and/or appropriate Tribal authorities when the owner or operator places information in the operating record, as well as to maintain a website for this information. Similar to legacy CCR surface impoundments, EPA is proposing that owners and operators of CCRMU be subject to certain recordkeeping, notification, and website reporting requirements in the CCR regulations. EPA is proposing that the applicable recordkeeping requirements in § 257.105, the notification requirements in § 257.106, and posting on a website requirements at § 257.107 would also apply to CCRMU. EPA is also proposing changes to add CCRMU to § 257.107(a) to require the facility to notify the Agency using the procedures for the establishment of the website no later than the effective date of the final rule.

C. Technical Corrections

Through the implementation of the 2015 CCR Rule, the Agency identified an incorrect CFR reference to the definition of technically feasible, technically infeasible, and wetlands. EPA also identified inconsistencies in how publicly accessible internet sites are referenced. Therefore, EPA is proposing to amend the CCR regulations so that the regulations clarify definitions, accurately reference the definition of wetlands, and use consistent language when referring to publicly accessible internet sites. The Agency is also proposing to amend an incorrect reference to § 257.99 in the groundwater monitoring scope section. Finally, EPA is requesting comment on extending the period for document retention and posting.

1. Definitions of “Technically Feasible” and “Technically Infeasible”

EPA is proposing to revise the definition of *technically feasible* to clarify that the terms *technically feasible* and *feasible* have the same meaning in the regulations. The existing regulations define *technically feasible* as “possible to do in a way that would likely be successful.” EPA codified this definition in 2020 when amending the alternative closure requirements for landfills and impoundments. 85 FR

53542 (August 28, 2020). As EPA explained, the definition was based on two dictionary definitions of “feasible”: “capable of being done or carried out” (Merriam website (<https://www.merriam-webster.com/dictionary/feasible>)) and “possible to do and likely to be successful” (Cambridge English Dictionary (<https://dictionary.cambridge.org/us/dictionary/english/feasible>)). Id.

However, some rule provisions use the term *feasible*. It is not the Agency's intent to distinguish between these terms. Therefore, EPA is proposing to add the term *feasible* to the existing definition of *technically feasible* to make clear that both terms have the same meaning in the regulations. This definition revision would be accomplished by adding “or feasible” to the existing definition so that the definition would read “*Technically feasible* or *feasible* means possible to do in a way that would likely be successful.” See proposed regulatory text at § 257.53.

For similar reasons, EPA is proposing to also revise the definition of *technically infeasible* to clarify that the terms *technically infeasible* and *infeasible* have the same meaning in the regulations. See proposed regulatory text at § 257.53.

2. Wetlands Reference Correction

When the 2015 CCR Rule was finalized in April 2015, § 257.61(a) referenced § 232.2 which contained a definition of wetlands. An EPA and United States Army Corps of Engineers joint final rule published June 29, 2015 (80 FR 37053) amended § 232.2 by removing the definition of wetlands. However, the reference to § 232.2 in § 257.61(a) of the 2015 CCR Rule was not updated. The proposed amendment would correct the CFR reference for the wetlands definition by referring to 40 CFR 230.41(a) (December 24, 1980, 45 FR 85344).

3. Groundwater Monitoring and Corrective Action Applicability

EPA is proposing to correct a typographical error in the initial applicability paragraph of the groundwater monitoring and corrective action regulations. In § 257.90(a), the existing regulations refer to the “groundwater monitoring and corrective action requirements under §§ 257.90 through 257.99”; however, there are no requirements codified under § 257.99. This was brought to our attention by a state interested in permit program approval. To avoid confusion with the regulations, EPA is proposing to revise the section references in § 257.90(a) to

read “groundwater monitoring and corrective action requirements under §§ 257.90 through 257.98.”

4. Publicly Accessible Internet Site

EPA is proposing to change several provisions using the term “CCR Web site” to “CCR website,” which is the term used in § 257.107(a). The inconsistent spelling of CCR website was brought to our attention by a state interested in permit program approval. To avoid confusion with the regulations, EPA is proposing to correct such references in §§ 257.100(e)(1)(iii) and 257.107(b) through (j).

5. Document Retention

EPA is taking comment on extending the period for document retention and posting found in §§ 257.105 and 257.107. The existing regulations generally require retention of documents in the operating record for a period of five years (§ 257.105(b)) and posting of documents on the facility publicly accessible CCR website for five years (§ 257.107(c)). The Agency now believes these time periods may be too short and that relevant information should remain publicly accessible for a longer time period. Under the existing requirements, information that is still relevant for CCR units could be removed from operating records and taken off websites well before the relevancy of that information has passed and goals of the record retention and posting requirements have been met. For example, for CCR unit closure plans that were posted in 2016 in accordance with § 257.102(b), the time periods have run, allowing closure plans to be removed from operating records and websites. This is true even if the facility has not initiated closure activity and may not initiate closure activity for many years. This was not consistent with EPA's original intent—either for the closure plan itself or for the posted information more generally—which was that the information should remain posted for as long as the information was relevant to evaluating the facility's compliance with the regulations. See, e.g., 80 FR 21335. The Agency continues to believe that much of the information, including plans, reports, and monitoring results, subject to the time period limits will remain relevant and should remain accessible for a much longer period than the original five years. The Agency is taking comment on how long these time periods should be extended. The Agency is considering a general increase in the retention period (e.g., fifteen years) or, alternatively, tying the retention period to a regulatory milestone for each unit (e.g., completion

of closure, post-closure care, or groundwater corrective action) and is seeking comment on which of these approaches, if any, the Agency should adopt. The Agency is considering this extension of retention time for all documents currently subject to the relevant retention time periods as all of these documents could remain relevant longer than the current time periods. Therefore, the goals of information availability and transparency would remain relevant for the CCR program.

V. Effect on State CCR Permit Programs

The proposed revisions to the CCR regulations would both establish standards for new types of units and revise existing requirements for CCR units defined in and subject to the 2015 CCR Rule. For this reason, if EPA takes final action on all the proposed changes, the requirements for approval and retention of a state CCR permit program in accordance with RCRA section 4005(d) will change. How these revisions would affect states depends on whether the state has received approval for the provisions that are ultimately included in any final rule and whether the state is seeking full or partial approval of its permit program.

If EPA has approved a state regulation pursuant to RCRA section 4005(d), that state regulation will continue to operate in lieu of the federal program, even if EPA subsequently revises the federal analog of that regulation. See 42 U.S.C. 6945(d)(1)(A), (3). In essence this means that any federal revisions would not take effect in the approved state until the state revises the program to adopt them. In order to maintain approval, the state must revise such a regulation within three years of any revision to the federal CCR regulation that is more protective. See, 42 U.S.C. 6945(d)(1)(D)(i)(II). Conversely, where EPA has not approved a state requirement, the federal requirements continue to apply directly to the facilities in that state. As a consequence, any revisions to the federal requirements will take effect in states without an approved program because the federal requirements continue to operate.

As discussed in Units IV.A and IV.B of this preamble, EPA is proposing to establish requirements for legacy CCR surface impoundments and CCRMU. Because legacy CCR surface impoundments and CCRMU are new types of federally regulated units, no state is currently approved to issue state CCR permits to such units in lieu of the federal CCR regulations. Thus, any state that wants approval to issue permits to such units will be required to update

the state CCR regulations and go through the state CCR permit program approval process set forth in RCRA section 4005(d).

As discussed in Units IV.B.9 and IV.C of this preamble, EPA is also proposing to revise requirements under the existing CCR regulations. The revised requirements will directly apply to affected facilities except to the extent EPA has already approved the state to issue permits for the original requirement. In such a case the state requirement will apply in lieu of the new federal requirement until the state program is revised. EPA considers at least one of these proposals (the proposal to expand § 257.102(d)(2) to landfills that are inundated with groundwater) to be more stringent than the existing regulations.

Accordingly, all states will have to consider whether to update their state CCR regulations and seek approval to issue permits for legacy CCR surface impoundments and CCRMU. In addition, states with approved CCR permit programs will be required to revise their regulations to address any new requirements applicable to CCR units, to the extent those requirements are more stringent than the approved state CCR permit program.⁷⁹ Similarly, states that are currently working with the Agency to obtain approval of their state CCR permit program will need to update their state programs to address the new requirements applicable to CCR units if the state wishes to seek full program approval and the new requirements are more stringent.⁸⁰

The process for approving modifications is the same as for the initial program approval: EPA will propose to approve or deny the program modification and hold a public hearing during the comment period. EPA will then issue the final program determination within 180 days of determining that the state's submission is complete.

EPA requests comment on the effect of this proposed rule on state CCR permit programs. EPA specifically requests comment on whether the proposed revisions to the existing requirements that apply to CCR units will be more stringent than the existing state CCR permit requirements, such that the states with approved programs

and states currently in the process of seeking approval would need to revise their state CCR permit program to retain or obtain approval, respectively.

VI. The Projected Economic Impact of This Action

A. Introduction

EPA estimated the costs and benefits of this action in a Regulatory Impact Analysis (RIA), which is available in the docket for this action.

B. Affected Universe

The universe of facilities and units affected by the proposed rule includes three categories. The first is comprised of facilities with legacy CCR surface impoundments. The RIA identifies 127 legacy CCR surface impoundments located at 59 facilities. The second component of the affected universe is composed of CCRMU. The RIA identifies 134 units at 82 facilities. The final component of the universe is comprised of CCR landfills that are already regulated under the 2015 CCR final rule, but which have waste in contact with groundwater. The RIA identifies 19 units.

C. Baseline Costs

The RIA examines the extent to which baseline practices at legacy CCR surface impoundments and CCRMU address contamination in a manner consistent with the requirements of the proposed rule. To the extent that legacy CCR surface impoundments and CCRMU are already sufficiently addressing contamination, they are assumed to not incur costs or realize benefits under the proposed rule. To estimate the proportion of legacy CCR surface impoundments addressing contamination in the baseline, the RIA examines relevant federal and state programs and determines that about 5.5% of legacy CCR surface impoundments are addressing site contamination. To estimate the proportion of CCRMU addressing contamination, the RIA examines publicly available filings from owners and operators of regulated coal fired power plants. The RIA estimates that about 34% of CCRMU are undergoing sitewide corrective action and closure in a manner sufficient to meet the requirements of the proposed rule.

D. Costs and Benefits of the Proposed Rule

The RIA estimates that the annualized costs of this action will be approximately \$413 million per year when discounting at 7%. Of this, \$237 million is attributable to the requirements for legacy CCR surface

⁷⁹ Currently the states of Georgia, Oklahoma, and Texas have approval for state CCR permit programs.

⁸⁰ Currently, EPA is working with the states of Alabama, Arizona, Florida, Illinois, Indiana, Kansas, Louisiana, Maryland, Michigan, North Carolina, North Dakota, Pennsylvania, Tennessee, Utah, Virginia, West Virginia, Wisconsin, and Wyoming on drafting CCR regulations or a draft CCR permit program.

impoundments, which are subject to the D.C. Circuit's order in *USWAG*, \$170 million is attributable to the requirements for CCRMU, and \$6 million is attributable to requirements for landfills. The RIA estimates that the annualized costs of this action will be approximately \$356 million when discounting at 3%. Of this, \$204 million is attributable to the requirements for legacy CCR surface impoundments, \$146 million is attributable to the requirements for CCRMU, and \$6 million is attributable to requirements for landfills. The costs of this proposed rule are discussed further in the RIA and include the costs of unit closure, corrective action, fugitive dust controls, structural integrity inspections, and recordkeeping and reporting.

The RIA estimates that the annualized monetized benefits attributable to this action will be approximately \$49 million per year when discounting at 7%. Of this, \$30 million is attributable to the requirements for legacy CCR surface impoundments, \$16 million is attributable to the requirements for CCRMU, and \$3 million is attributable to requirements for landfills. The RIA estimates that the annualized monetized benefits attributable to this action will be approximately \$77 million per year when discounting at 3%. Of this, \$47 million is attributable to the requirements for legacy CCR surface impoundments, \$25 million is attributable to the requirements for CCRMU, and \$5 million is attributable to requirements for landfills. The monetized benefits of this proposed rule are discussed further in the RIA, and include reduced incidents of cancer from the consumption of arsenic in drinking water, avoided intelligence quotient (IQ) losses from mercury and lead exposure, non-market benefits of water quality improvements, and the protection of threatened and endangered species. EPA also monetized the benefits of avoided impoundment failures, including both "catastrophic" failures and smaller-volume releases. One example of a severe impoundment failure is the Dan River Steam Station failure which occurred in 2014, when a stormwater drainage pipe under the inactive surface impoundments at the Dan River Steam Station caused the inadvertent release of 39,000 tons of CCR directly into the nearby Dan River. The result high-end estimate of the costs of this impoundment failure is \$300 million.

The RIA also describes a number of important benefits that cannot currently be quantified or monetized due to data limitations or limitations in current methodologies. These benefits include

reducing the baseline risk of unit leakage and failure attributable to climate-change driven severe weather events. Many legacy CCR surface impoundments and CCRMU are situated close to rivers or are located along the coast. These units are vulnerable to inland or coastal flooding, which may occur at an increased frequency due to the effects of climate change. Flooding events may cause these units to overtop or catastrophically collapse, releasing CCR into the environment, exposing nearby communities to toxic contamination and necessitating potentially costly cleanup and remediation. EPA has identified 36 legacy CCR impoundments at medium or high risk from climate change driven flooding, and 27 CCRMU at medium or high risk from climate change driven flooding.

Another set of benefits outside the scope of quantification include reducing the instance of negative human health impacts such as cardiovascular mortality, neurological effects, and cancers (separate from the quantified cancer benefits) brought on by exposure to toxins found in coal ash. Either through leaking impoundment sites or release events, many pollutants from legacy CCR surface impoundments are likely to contaminate nearby water bodies, affecting surface waters, local fish populations, and drinking water reservoirs. Because known transport pathways exist between these release events and human health endpoints, EPA expects the proposed rule to cause risk reductions for various categories that are not yet quantifiable. Toxins such as thallium, molybdenum, and lithium, while all present in CCR, lack the data to create dose-response relationships between ingestion rates and specific health endpoints, and thus precludes EPA from quantifying associated benefits.

The RIA describes several surface water quality benefits such as the improved health of ecosystems proximate to CCR disposal units, and the avoided costs of treating public drinking water impacted by CCR contamination. EPA expects leakages or releases of effluent from any CCR surface impoundment site to contaminate nearby surface waters and environments. Introduction of arsenic, selenium, and other heavy metals associated with CCR surface impoundment contents are shown to accumulate in sediments of nearby stream and lake beds, posing risks and injury to organisms and consequently ecosystems. Although surface waters are broadly protected from high levels of contaminants under EPA's regulations

and Water Quality Criteria (WQC), complex interactions from trace amounts of heavy metals and other toxins known to be released from legacy CCR surface impoundment sites have displayed measurable impact to aquatic animals and ecosystems.⁸¹

The proposed rule may result in avoided drinking water treatment costs and drinking water quality improvements at public water systems. First, by reducing the risk of CCR leakage events and impoundment failures, the proposed rule will help avoid costs of water quality treatment at public intake sources. Second, by preventing release events the proposed rule has the potential to reduce the incidence of eutrophication in source waters for public drinking supplies. Eutrophication is primarily caused by an overabundance of nitrogen and phosphorus. It causes foul tastes and odors, which require additional treatment, and commensurate expenditure, to remove.

The RIA discusses potential impacts on the market for the beneficial use of CCR as a substitute for virgin materials. Future uses of CCR are unknown. Research on the recovery of rare earth elements and yttrium from coal fly ash is ongoing but currently only at laboratory scale. It is possible that in the future, the availability of additional CCR may reach an equilibrium price that encourages demand, particularly as coal plants retire and the supply of "new" CCR falls. However, the quality of CCR in legacy CCR surface impoundments and CCRMU may limit their value. Older, closed impoundments or other CCR storage areas are less likely to have CCR material of a known and reliable composition.

The RIA also discusses potential reductions in fugitive dust emanating from legacy CCR surface impoundments, which will benefit fence line communities by reducing the amount of resuspended ash from legacy CCR surface impoundments that could otherwise lead to respiratory health hazards for communities surrounding a given legacy surface impoundment.

The RIA discusses the benefits of improved property values near closed and remediated sites. Neighborhoods located near hazardous waste sites often experience depressed property values due to health risks posed by contaminant exposure pathways, potential reductions in ecological services, unsightly aesthetics of the

⁸¹ Brandt, Jessica E., et al. "Beyond selenium: coal combustion residuals lead to multielement enrichment in receiving lake food webs." *Environmental science & technology* 53.8 (2019): 4119–4127.

disposal unit site, and potential stigma associated with proximity to a disposal site. Almost a million households, and over 2.5 million people are located within 3 miles of legacy CCR surface impoundments and CCRMU.

Approximately 75,000 households and 200,000 people are located within a mile. Improvements in home values resulting from the proposed rule have the potential to bestow welfare gains to homeowners located near legacy CCR units and CCR management units.

The RIA also discusses the value of reusing land formerly occupied by legacy CCR surface impoundments, and CCRMU. Once legacy CCR surface impoundments and CCRMU are closed by removal, or landfills are properly capped, or corrective action activities are completed, the land is more likely to move into alternative, economically productive purposes. For example, these land reuse projects might include industrial redevelopment or implementation of green energy generation which can utilize the existing electricity grid infrastructure.

Finally, based on the demographic composition and environmental conditions of communities within one and three miles of legacy CCR surface impoundments, these proposals will reduce existing disproportionate and adverse effects on economically vulnerable communities, as well as those that currently face environmental burdens. For example, in Illinois the population living within 1 mile of legacy CCR surface impoundment sites is over three times as likely compared to the state average to have less than a high school education (35.66% compared to 10.10%, see RIA exhibit ES.14), and that population already experiences higher than average exposures to particulate matter, ozone, diesel emissions, lifetime air toxics cancer risks, and proximity to traffic, Superfund sites, Risk Management Plan sites, and hazardous waste facilities (see RIA exhibit ES.15).

The RIA also discusses the interaction of the CCR rules with Air rules governing emissions at power plants. Following on the significant progress EPA has made over many decades to reduce dangerous pollution from coal-fired electric utilities' stack emissions and effluents, this proposed rule will help EPA further ensure that the communities and ecosystems closest to coal facilities are sufficiently protected from harm from groundwater contamination, surface water contamination, fugitive dust, floods and impoundment overflows, and threats to wildlife. The volume and toxicity of CCR at many sites persisted or increased

over past decades even as coal-fired units' air and water emissions decreased, and this proposed rule will help EPA fulfill the promise of substantial public health and welfare gains from its full suite of regulations aimed at reducing the harms from coal-combustion pollution.

As noted previously, EPA establishes the requirements under RCRA sections 1008(a)(3) and 4004(a) without taking cost into account. See, *USWAG*, 901 F.3d at 448–49. Although EPA has accordingly designed its proposal based on its statutory factors and court precedent and has not relied on this benefit-cost analysis in the selection of its proposed alternative, EPA believes that after considering all unquantified and distributional effects, the public health and welfare gains that will result from the proposed alternative would justify the rule's costs.

Under section 3(f)(1) of Executive Order 12866, this action is considered a significant action.

VII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at <https://www.epa.gov/laws-regulations/laws-and-executive-orders>.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of Executive Order 12866, this action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to recommendations received as part Executive Order 12866 review have been documented in the docket. EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, Regulatory Impact Analysis: Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments, is available in the docket. and is briefly summarized in section VII.

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 the EPA prepared has been assigned EPA ICR number 2761.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The proposed rule requires legacy CCR surface impoundments to comply with the reporting and recordkeeping requirements already in place for regulated CCR units. Many of these requirements are one-time requirements that will occur soon after the promulgation of the rule, while several are ongoing. The proposed rule also requires legacy CCR surface impoundments to submit an applicability report, unique to this universe of units, which will provide stakeholders with essential site characteristic and contact information for the unit.

Respondents/affected entities: Inactive coal fired electric utility plants with inactive CCR surface impoundments (legacy CCR surface impoundments), coal-fired electric utility plants with CCRMU, and coal-fired electric utility plants with landfills already subject to regulation under the 2015 final CCR rule, but which have waste in contact with groundwater.

Respondent's obligation to respond: The recordkeeping, notification, and posting are mandatory as part of the minimum national criteria promulgated under Sections 1008(a), 2002(a), 4004, and 4005(a) and (d) of RCRA.

Estimated number of respondents: 273.

Frequency of response: one-time and annually.

Total estimated burden: 70,700 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: \$24.4 million (per year), includes \$20.4 million 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. One may 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 July 17, 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. The small entities subject to the requirements of this action are owners and operators of coal fired electric utility plants in NAICS code 221112 and firms that own property on which an inactive/retired coal fired power plant is located. The Agency has identified 11 small entities subject to the proposed rule. The Agency estimates that the average annual cost to a small entity that owns CCRMU will be approximately \$2.8 million, and the average annual cost to a small entity that owns legacy CCR surface impoundments will be about \$2.1 million. EPA makes two assumptions about how small entities will comply with the rule. First, EPA assumes that the units owned by small entities will all require corrective action, and will undergo closure by removal. Second, EPA assumes that small entities will not be able to pass on any compliance costs to ratepayers. These assumptions, in EPA's opinion, constitute a high-end scenario. Eight small entities are estimated to own CCRMU, for an annual cost of approximately \$23 million. Three small entities are estimated to own legacy CCR surface impoundments for an annual cost of approximately \$6.5 million. In total small entities are estimated to incur approximately \$29.5 million in annual costs. The Agency has determined that one small entity may experience an impact above 1% of annual revenues but below 3% of annual revenues, and one small entity may experience an impact greater than 3% of annual revenues. Details of this analysis are presented in the Regulatory Impact Analysis, which can be found in the docket for this action.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of \$100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA has prepared a written statement required under section 202 of UMRA. The statement is included in the docket for this action and briefly summarized here.

The RIA estimates that the proposed rule may affect 127 legacy CCR surface impoundments at 59 facilities, 134 CCRMU at 82 facilities, and 29 landfills already regulated under the 2015 final rule. The proposed rule will extend the

existing requirements of the 2015 CCR final rule, found in 40 CFR part 257, subpart D, to these units.

In preparing the 2015 CCR final rule, and consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA initiated pre-proposal consultations with governmental entities affected by the rule. In developing the regulatory options for the 2015 CCR Rule, EPA consulted with small governments according to EPA's UMRA interim small government consultation plan developed pursuant to section 203 of UMRA. The details of this consultation can be found in the preamble to the 2015 CCR final rule. Consistent with section 205 of UMRA, EPA identified and considered a reasonable number of regulatory alternatives, and adopted the least-costly approach (*i.e.*, a modified version of the "D Prime" least costly approach presented in the 2010 proposed CCR rule). The proposed rule merely extends the provisions of the 2015 final rule to three additional classes of facilities.

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. The threshold amount established for determining whether regulatory requirements could significantly affect small governments is \$100 million annually. The RIA estimates annual average costs of \$5 million total for the two local governments identified as owning units subject to the proposed rule. These estimates are well below the \$100 million annual threshold established under UMRA. There are no known tribal owner entities of facilities that would incur substantial direct costs under the proposed rule.

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. For the "Final Rule: Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities" published April 17, 2015 (80 FR 21302), EPA identified three of the

414 coal-fired electric utility plants (in operation as of 2012) as being located on tribal lands. To the extent that these plants contain CCRMU subject to the proposed rule, the impacts to tribes will be limited to document review and walking the site. As these are not substantial direct costs, this action does not impose substantial direct compliance costs or otherwise have a substantial direct effect on one or more Indian tribes, to the best of EPA's knowledge. Neither will it have substantial direct effects 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. 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 E.O. 13045 (62 FR 19885, April 23, 1997) because it is a significant regulatory action under section 3(f)(1) of E.O. 12866, and EPA believes that the environmental health or safety risks addressed by this action may have a disproportionate effect on children. Accordingly, EPA evaluated the environmental health or safety effects of CCR constituents of potential concern on children. The results of this evaluation are contained in the Human and Ecological Risk Assessment of Coal Combustion Wastes available in the docket for this action.

As ordered by E.O. 13045 Section 1–101(a), EPA identified and assessed environmental health risks and safety risks that may disproportionately affect children in the revised risk assessment. Pursuant to U.S. EPA's Guidance on Selecting Age Groups for Monitoring and Assessing Childhood Exposures to Environmental Contaminants, children are divided into seven distinct age cohorts: 1 to <2 yr, 2 to <3 yr, 3 to <6 yr, 6 to <11 yr, 11 to <16 yr, 16 to <21 yr, and infants (<1 yr). Using exposure factors for each of these cohorts, EPA calculated cancer and non-cancer risk results in both the screening and probabilistic phases of the assessment. In general, risks to infants tended to be higher than other childhood cohorts, and also higher than risks to adults. However, for drinking water cancer risks, the longer exposures for adults led to the highest risks. Screening risks exceeded EPA's human health criteria for children exposed to contaminated air, soil, and food resulting from fugitive dust emissions and run-off. Similarly, 90th percentile child cancer and non-cancer risks exceeded the human health

criteria for the groundwater to drinking water pathway under the full probabilistic analysis (Table 5–17 in the Human and Ecological Risk Assessment of Coal Combustion Wastes). The closure, groundwater monitoring and corrective action required by the rule will reduce risks from currently unregulated legacy CCR surface impoundments, and waste management units. Thus, EPA believes that this rule will be protective of children's health.

In general, because the pollution control requirements under the CCR rule will reduce health and environmental exposure risks at all coal-fired electric utility plants, the CCR rule is not expected to create additional or new risks to children.

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. Because the proposed rule addresses management of CCR and pertains solely to inactive CCR units (legacy CCR surface impoundments at inactive facilities and CCR management units at facilities already regulated under the 2015 CCR rule), this proposed rule will have no effect on the production of crude oil, coal, fuel, or natural gas. In addition, the proposed rule will have no direct effect on electricity production, generating capacity, or on foreign imports or exports of energy.

Electricity price effects on the price of energy are only possible because in some cases, utilities may attempt to pass the costs of managing CCR under the proposed rule on to ratepayers in the form of increased electricity rates through Public Utility Commissions (PUCs). As a result, the proposed rule may indirectly affect electricity prices within the energy sector. To estimate what the electricity price effects of this proposed rule may be on a national level, EPA compared the expected costs of this rule to the expected costs and effects resulting from three previously conducted IPM runs for three previous RIAs, the 2015 CCR Rule, the 2015 ELG Rule (which included the costs of the 2015 CCR Rule in its baseline), and the 2019 ELG Rule, which was a deregulatory rule. Extrapolating from these IPM runs, EPA estimates that the effect of the current action on electricity prices will be between 0.042% and 0.125%. Since these effects fall below the 1% threshold, EPA concludes that this rule is not expected to generate significant adverse energy effects. The

full energy impacts analysis is available in the Regulatory Impact Analysis that accompanies this action.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking involves technical standards. EPA has decided to use the following technical standards in this rule: (1) RCRA Subpart D, Section 257.70 liner design criteria for new CCR landfills and any lateral expansion of a CCR landfill includes voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, (2) Section 257.71 liner design criteria for existing CCR surface impoundments includes voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, (3) Section 257.72 liner design criteria for new CCR surface impoundments and any lateral expansion of a CCR surface impoundment includes voluntary consensus standards developed by ASTM International and EPA test methods such as SW–846, and (4) Section 257.73 structural stability standards for new and existing surface impoundments use the ASTM D 698 and 1557 standards for embankment compaction.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice (EJ) part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on communities with environmental justice concerns.

EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns.

EPA conducted a demographic screening analysis for all legacy CCR surface impoundments and CCRMU to determine the composition of populations living within one and three miles of facilities with these units. Specifically, EPA looked at the percentages of the relevant populations that are identified as minority/people of color, households below the federal poverty level, population with less than high school education (among those 25

years and older), and populations characterized by linguistic isolation. EPA chose to look at radii of one and three miles because they represent the areas most likely to be affected by groundwater contamination from legacy CCR surface impoundments and CCRMU. EPA compared the demographic profile within these radii to national averages to assess the extent to which marginalized groups are disproportionately affected by contamination from legacy CCR surface impoundments and CCRMU in the baseline. EPA found that the following demographic and socioeconomic indicators were more highly represented within one and three miles of sites containing legacy CCR surface impoundments than the U.S. national averages: minority/people of color, Black population, Native American population, Hispanic ethnicity, households below the poverty level, less than high school education, and linguistic isolation. EPA found that the following demographic and socioeconomic indicators were more highly represented within one and three miles of CCRMU: Black population, “Other” racial groups, households below the poverty level, and less than high school education. EPA also compared a subset of three population indicators, minority status, less than high school education and linguistic isolation, around legacy CCR surface impoundments and CCRMU against state level population characteristics. In eight of the 25 states (32%) containing legacy CCR surface impoundments affected by the proposed rule, at least one of these three demographic indicators for populations within one mile of the facility was above twice the state average value. In five of the 28 states (18%) containing CCRMU affected by the proposed rule, at least one of the three demographic indicators for populations within one mile of the facility was above twice the state average value.

EPA also examined the cumulative environmental impacts that exist around facilities in the affected universe. EPA looked at the following eight environmental indicators, PM 2.5, O₃, Diesel PM, Lifetime Cancer Risk, Traffic Proximity, National Priorities List (NPL) Proximity, Risk Management Plan (RMP) Proximity, and Transportation Storage and Disposal Facility (TSDF) proximity within one mile of facilities in the affected universe. Because environmental indicators are not available at the national level, EPA confined this analysis to states where at least one facility registered twice the

state average on any of the eight environmental indicators. Nine states contain such facilities, and in six of them at least half of the environmental indicators within a mile of facilities containing legacy units were higher than state averages. At the state level, therefore, environmental issues seem to cluster, uniquely impacting communities living within a mile of legacy and management units.

Based on the results of these demographic screening analyses, EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns.

EPA believes that this action is likely to reduce existing disproportionate and adverse effects on communities with environmental justice concerns. Neighborhoods located near legacy CCR surface impoundments and CCR management units are disproportionately occupied by communities with environmental justice concerns. These vulnerable communities face risks of impoundment failure, groundwater contamination, and fugitive air emissions. If such failures or contamination occur, nearby residents will face risks to their health, both cancer and noncancer. Other risks include damage to ecosystem services and environmental amenities. These communities are likely to face existing environmental burdens that put them at greater cumulative risk from the environmental impacts associated with proximity to legacy units. EPA believes that the proposed rule is likely to incrementally reduce baseline disproportionate and adverse effects on communities with environmental justice concerns by requiring closure and corrective action at legacy CCR surface impoundments and CCRMU, thereby reducing the risks of exposure to contamination from CCR faced by these populations. The analyses above examining the demographic composition and environmental conditions of communities within one and three miles of legacy CCR surface impoundments and CCRMU highlight the higher potential incidence of EJ issues in more demographically vulnerable communities. They demonstrate that the proposed rule is likely to improve conditions for nearby communities from the baseline, as these communities are more likely than the national average to be more vulnerable to environmental harms due to their demographics and economic vulnerability and are currently facing

existing environmental burdens. It is important to note that proximity to traffic could remain a significant EJ issue and in fact be exacerbated by the proposed rule if removal of CCR from plants with legacy units is undertaken using heavy-duty vehicles and routes that run through residential areas. EJ concerns related to traffic will need to be assessed at a site-by-site level in conversation with nearby communities as EPA implements the proposed rule.

The information supporting this Executive Order review is contained in the accompanying Regulatory Impact Analysis, which can be found in the docket for this action.

List of Subjects in 40 CFR Part 257

Environmental protection, Beneficial use, Coal combustion products, Coal combustion residuals, Coal combustion waste, Disposal, Hazardous waste, Landfill, Surface impoundment.

Michael S. Regan,
Administrator.

For the reasons set out in the preamble, EPA proposes to amend 40 CFR part 257 as follows:

PART 257—CRITERIA FOR CLASSIFICATION OF SOLID WASTE DISPOSAL FACILITIES AND PRACTICES

- 1. The authority citation for part 257 continues to read as follows:

Authority: 42 U.S.C. 6907(a)(3), 6912(a)(1), 6944, 6945(a) and (d); 33 U.S.C. 1345(d) and (e).

- 2. Amend § 257.1 by revising paragraph (c)(12) to read as follows:

§ 257.1 Scope and purpose.

* * * * *

(c) * * *

(12) Except as otherwise specifically provided in subpart D of this part, the criteria in subpart A of this part do not apply to CCR landfills, CCR surface impoundments, lateral expansions of CCR units, and CCR management units, as those terms are defined in subpart D of this part. Such units are instead subject to subpart D of this part.

Subpart D [AMENDED]

- 3. Amend subpart D by remove the phrase “Web site” and adding in its place the word “website” everywhere it appears.
- 4. Amend § 257.50 by revising paragraph (c), (d), and (e) to read as follows:

§ 257.50 Scope and purpose.

* * * * *

(c) This subpart also applies to inactive CCR surface impoundments at active electric utilities or independent power producers, regardless of how electricity is currently being produced at the facility.

(d) This subpart applies to CCR management units located at active or inactive facilities with a CCR unit.

(e) This subpart applies to electric utilities or independent power producers that have ceased producing electricity prior to October 19, 2015 and that have a legacy CCR surface impoundment.

* * * * *

- 5. Revise § 257.52 to read as follows:

§ 257.52 Applicability of other regulations.

(a) Compliance with the requirements of this subpart does not affect the need for the owner or operator of a CCR landfill, CCR surface impoundment, lateral expansion of a CCR unit, or CCR management unit to comply with all other applicable federal, state, tribal, or local laws or other requirements.

(b) Any CCR landfill, CCR surface impoundment, lateral expansion of a CCR unit, or CCR management unit continues to be subject to the requirements in §§ 257.3–1, 257.3–2, and 257.3–3.

- 6. Amend § 257.53 by:

- a. Revising the definitions of “Active life or in operation”, “Active portion”, “Closed”, and “CCR landfill or landfill”;
- b. Adding the definition of “CCR management unit” in alphabetical order;
- c. Revising the definitions of “CCR unit”;
- d. Adding the definition of “Inactive CCR landfill” in alphabetical order;
- e. Revising the definition of “Inactive CCR surface impoundment”;
- f. Adding the definitions of “Inactive facility or inactive electric utility or independent power producer” and “Legacy CCR surface impoundment” in alphabetical order; and
- g. Revising the definitions of “Operator”, “Owner”, “Qualified person”, “Qualified professional engineer”, “State Director”, “Technically feasible or feasible”, “Technically infeasible or infeasible”, and “Waste boundary”.

The revisions and additions read as follows:

§ 257.53 Definitions.

* * * * *

Active life or in operation means the period of operation beginning with the initial placement of CCR in the CCR unit or CCR management unit and ending at completion of closure activities in accordance with § 257.102.

Active portion means that part of the CCR unit or CCR management unit that has received or is receiving CCR or non-CCR waste and that has not completed closure in accordance with § 257.102.

* * * * *

Closed means placement of CCR in a CCR unit or CCR management unit has ceased, and the owner or operator has completed closure of the CCR unit or CCR management unit in accordance with § 257.102 and has initiated post-closure care in accordance with § 257.104.

* * * * *

CCR landfill or landfill means an area of land or an excavation that receives CCR and which is not a surface impoundment, a CCR management unit, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine, or a cave. For purposes of this subpart, a CCR landfill also includes sand and gravel pits and quarries that receive CCR, CCR piles, and any practice that does not meet the definition of a beneficial use of CCR.

CCR management unit means any area of land on which any non-containerized accumulation of CCR is received, placed, or otherwise managed at any time, that is not a CCR unit. This includes inactive CCR landfills and CCR units that closed prior to October 17, 2015.

* * * * *

CCR unit means any CCR landfill, CCR surface impoundment, or lateral expansion of a CCR unit, or a combination of more than one of these units, based on the context of the paragraph(s) in which it is used. This term includes both new and existing units, unless otherwise specified. This term does not include CCR management units.

* * * * *

Inactive CCR landfill means an area of land or an excavation that contains CCR but that no longer receives CCR on or after the effective date of the final rule and that is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface coal mine, or a cave. For purposes of this subpart, this term also includes sand and gravel pits that received CCR, and abandoned CCR piles.

Inactive CCR surface impoundment means a CCR surface impoundment located at an active facility that no longer receives CCR on or after October 19, 2015, and still contains both CCR and liquids on or after October 19, 2015.

Inactive facility or inactive electric utility or independent power producer

means any facility with a legacy CCR surface impoundment subject to the requirements of this subpart that ceased operation prior to October 19, 2015. An electric utility or independent power producer is no longer in operation if it has ceased generating electricity provided to electric power transmission systems or to electric power distribution systems before October 19, 2015. An inactive facility does not include an off-site disposal facility that ceased operation prior to October 19, 2015.

* * * * *

Legacy CCR surface impoundment means a CCR surface impoundment that no longer receives CCR but contained both CCR and liquids on or after October 19, 2015, and that is located at an inactive electric utility.

* * * * *

Operator means the person(s) responsible for the overall operation of a CCR unit or CCR management unit. This term includes those person(s) or parties responsible for disposal or otherwise actively engaged in the solid waste management of CCR. It also includes those responsible for directing or overseeing groundwater monitoring, closure or post-closure activities at a CCR unit or CCR management unit.

* * * * *

Owner means the person(s) who owns a CCR unit or CCR management unit or part of a CCR unit or CCR management unit, or a facility, whether in full or in part.

* * * * *

Qualified person means a person or persons trained to recognize specific appearances of structural weakness and other conditions which are disrupting or have the potential to disrupt the operation or safety of the CCR unit or CCR management unit by visual observation and, if applicable, to monitor instrumentation.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in the state where the CCR unit(s) or CCR management unit is located.

* * * * *

State Director means the chief administrative officer of the lead state agency responsible for implementing the state program regulating disposal in CCR landfills, CCR surface

impoundments, all lateral expansions of a CCR unit, and CCR management units.

* * * * *

Technically feasible or feasible means possible to do in a way that would likely be successful.

Technically infeasible or infeasible means not possible to do in a way that would likely be successful.

* * * * *

Waste boundary means a vertical surface located at the hydraulically downgradient limit of the CCR unit or CCR management unit. The vertical surface extends down into the uppermost aquifer.

■ 7. Amend § 257.61 by revising the introductory text of paragraph (a) to read as follows:

§ 257.61 Wetlands.

(a) New CCR landfills, existing and new CCR surface impoundments, and all lateral expansions of CCR units must not be located in wetlands, as defined in § 230.41(a) of this chapter, unless the owner or operator demonstrates by the dates specified in paragraph (c) of this section that the CCR unit meets the requirements of paragraphs (a)(1) through (5) of this section.

* * * * *

■ 8. Add § 257.75 to subpart D to read as follows:

§ 257.75 Requirements for identifying CCR management units.

(a) *Applicability.* The requirements of this section apply to owners and operators of active or inactive facilities with one or more CCR unit(s).

(b) *Facility evaluation.* Upon the effective date of the final rule, the owner or operator of an active facility or inactive facility with one or more CCR unit(s) must initiate a facility evaluation to identify all CCR management units at the facility. At a minimum, the presence or absence of CCR management units at the facility must be confirmed and documented through a thorough evaluation of available records that contain the information needed to prepare the Facility Evaluation Report required by paragraph (c) of this section. The facility evaluation must include a physical inspection of the facility. Where necessary, the physical inspection must additionally include field investigation activities to fill data gaps, such as conducting exploratory soil borings, geophysical assessments, or any other similar physical investigation activities to establish the location and boundaries of identified CCR management units, and to affirmatively rule out other areas of potential CCR placement at the facility that were identified during the information

review. The facility evaluation must identify all CCR management units at the facility regardless of when the CCR management unit came into existence.

(c) *Facility evaluation report.* No later than 3 months after the effective date of the final rule, the owner or operator of an active or inactive facility that contains CCR units regulated under this subpart must prepare a Facility Evaluation Report, which shall contain, to the extent available, the information specified in paragraphs (c)(1) through (13) of this section. The owner or operator has prepared the Facility Evaluation Report when the report has been placed in the facility's operating record as required by § 257.105(f)(25).

(1) The name and address of the person(s) owning and operating the facility; the unit name associated with any CCR unit and CCR management unit at the facility; and the identification number of each CCR unit and CCR management unit if any have been assigned by the state.

(2) The location of any CCR management unit identified on the most recent U.S. Geological Survey (USGS) 7 1/2 minute or 15-minute topographic quadrangle map, or a topographic map of equivalent scale if a USGS map is not available. The location of each CCR unit at the facility must also be identified.

(3) A statement of the purpose(s) for which each CCR management unit at the facility is or was being used.

(4) A description of the physical and engineering properties of the foundation and abutment materials on which each CCR management unit is constructed.

(5) A discussion of any known spills or releases of CCR from each CCR management unit and whether the spills or releases were reported to state or federal agencies.

(6) Any record or knowledge of structural instability of each CCR management unit.

(7) Any record or knowledge of groundwater contamination associated with each CCR management unit.

(8) Size of each CCR management unit, including the general dimensions and an estimate of the volume of waste contained within the unit.

(9) Dates when each CCR management unit first received CCR and when each CCR management unit ceased receiving CCR.

(10) Specification of all CCR wastes that have been managed in each CCR management unit at the facility.

(11) A narrative description, including any applicable engineering drawings or reports of any closure activities that have occurred.

(12) A narrative that documents the nature and extent of field oversight

activities and data reviewed as part of the facility evaluation process, and that lists all data and information that was reviewed indicating the absence of CCR management units at the facility.

(13) Any supporting information used to identify and evaluate CCR management units at the facility, including but not limited to any construction diagrams, engineering drawings, permit documents, wastestream flow diagrams, aerial photographs, satellite images, historical facility maps, any field or analytical data, groundwater monitoring data or reports, inspection reports, documentation of interviews with current or former facility workers, and other documents used to identify and assess CCR management units at the facility.

(d) The owner or operator of any facility regulated under this subpart must obtain a certification from a qualified professional engineer stating that the Facility Evaluation Report meets the requirements of paragraph (c) of this section.

(e) The owner or operator of any facility regulated under this subpart must certify the Facility Evaluation Report required by paragraph (c) of this section with the following statement signed by the owner or operator or an authorized representative:

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

(f) The owner or operator of any facility regulated under this subpart that does not contain any CCR management unit must submit a Facility Evaluation Report documenting the steps taken during the facility evaluation to determine the absence of any CCR management unit. The Facility Evaluation Report must include the certifications required under paragraphs (d) and (e) of this section.

(g) The owner or operator of the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(f)(25), the notification requirements specified in § 257.106(f)(24), and the internet requirements specified in § 257.107(f)(24).

■ 9. Amend § 257.80 by revising paragraphs (a), (b) introductory text,

(b)(6), the first sentence of (c), and (d) to read as follows:

§ 257.80 Air criteria.

(a) The owner or operator of a CCR landfill, CCR surface impoundment, any lateral expansion of a CCR unit, or CCR management unit must adopt measures that will effectively minimize CCR from becoming airborne at the facility, including CCR fugitive dust originating from CCR units, roads, and other CCR management and material handling activities.

(b) *CCR fugitive dust control plan.* The owner or operator of the CCR unit or CCR management unit must prepare and operate in accordance with a CCR fugitive dust control plan as specified in paragraphs (b)(1) through (7) of this section. This requirement applies in addition to, not in place of, any applicable standards under the Occupational Safety and Health Act.

* * * * *

(6) *Amendment of the plan.* The owner or operator subject to the requirements of this section may amend the written CCR fugitive dust control plan at any time provided the revised plan is placed in the facility's operating record as required by § 257.105(g)(1). The owner or operator must amend the written plan whenever there is a change in conditions that would substantially affect the written plan in effect, such as the construction and operation of a new CCR unit.

* * * * *

(c) *Annual CCR fugitive dust control report.* The owner or operator of a CCR unit or a CCR management unit must prepare an annual CCR fugitive dust control report that includes a description of the actions taken by the owner or operator to control CCR fugitive dust, a record of all citizen complaints, and a summary of any corrective measures taken. * * *

(d) The owner or operator of the CCR unit or a CCR management unit must comply with the recordkeeping requirements specified in § 257.105(g), the notification requirements specified in § 257.106(g), and the internet requirements specified in § 257.107(g).

■ 10. Amend § 257.90 by:

■ a. Revising paragraph (a);

■ b. Adding paragraph (b)(3); and

■ c. Revising paragraphs (c), (d), (e) introductory text, (e)(1), (e)(6) introductory text, (e)(6)(i), (ii), (e)(6)(iii)(B), (e)(6)(iv)(B), (C), (D), and (f).

The revisions and addition read as follows:

§ 257.90 Applicability.

(a) *Applicability.* All CCR landfills, CCR surface impoundments, lateral expansions of CCR units, and CCR management units are subject to the groundwater monitoring and corrective action requirements under §§ 257.90 through 257.98, except as provided in paragraph (g) of this section.

(b) * * *

(3) *CCR management units.* The owner or operator of the CCR management unit must be in compliance with the following groundwater monitoring requirements by the dates specified in paragraphs (b)(3)(i) through (iv) of this section:

(i) *Groundwater monitoring system installation.* No later than 6 months after the effective date of the final rule, install the groundwater monitoring system as required by § 257.91.

(ii) *Groundwater monitoring sampling and analysis program.* No later than 6 months after the effective date of the final rule, develop the groundwater sampling and analysis program to include selection of the statistical procedures to be used for evaluating groundwater monitoring data as required by § 257.93.

(iii) *Initiation of detection monitoring and assessment monitoring.* No later than 24 months after the effective date of the final rule, be in compliance with the following groundwater monitoring requirements:

(A) Initiate the detection monitoring program to include obtaining a minimum of eight independent samples for each background and downgradient well, as required by § 257.94(b).

(B) Begin evaluating the groundwater monitoring data for statistically significant increases over background levels for the constituents listed in appendix III of this part, as required by § 257.94.

(C) Begin evaluating the groundwater monitoring data for statistically significant levels over groundwater protection standards for the constituents listed in appendix IV of this part as required by § 257.95.

(c) Once a groundwater monitoring system and groundwater monitoring program has been established at the CCR unit or a CCR management unit as required by this subpart, the owner or operator must conduct groundwater monitoring and, if necessary, corrective action throughout the active life and post-closure care period of the CCR unit or a CCR management unit.

(d) In the event of a release from a CCR unit or a CCR management unit, the owner or operator must immediately take all necessary measures to control the source(s) of releases so as to reduce

or eliminate, to the maximum extent feasible, further releases of contaminants into the environment. The owner or operator of the CCR unit or a CCR management unit must comply with all applicable requirements in §§ 257.96, 257.97, and 257.98.

(e) For existing CCR landfills and existing CCR surface impoundments, no later than January 31, 2018, and annually thereafter, the owner or operator must prepare an annual groundwater monitoring and corrective action report. For new CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units, the owner or operator must prepare the initial annual groundwater monitoring and corrective action report no later than January 31 of the year following the calendar year a groundwater monitoring system has been established for such CCR unit as required by this subpart, and annually thereafter. For CCR management units, the owner or operator must prepare the initial annual groundwater monitoring and corrective action report no later than January 31 of the year following the calendar year a groundwater monitoring system has been established for such CCR management unit as required by this subpart, and annually thereafter. For the preceding calendar year, the annual report must document the status of the groundwater monitoring and corrective action program for the CCR unit or the CCR management unit, summarize key actions completed, describe any problems encountered, discuss actions to resolve the problems, and project key activities for the upcoming year. For the purposes of this section, the owner or operator has prepared the annual report when the report is placed in the facility's operating record as required by § 257.105(h)(1). At a minimum, the annual groundwater monitoring and corrective action report must contain the following information, to the extent available:

(1) A map, aerial image, or diagram showing the CCR unit or the CCR management unit and all background (or upgradient) and downgradient monitoring wells, to include the well identification numbers, that are part of the groundwater monitoring program for the CCR unit or the CCR management unit;

* * * * *

(6) A section at the beginning of the annual report that provides an overview of the current status of groundwater monitoring and corrective action programs for the CCR unit or the CCR management unit. At a minimum, the

summary must specify all of the following:

(i) At the start of the current annual reporting period, whether the CCR unit or the CCR management unit was operating under the detection monitoring program in § 257.94 or the assessment monitoring program in § 257.95;

(ii) At the end of the current annual reporting period, whether the CCR unit or the CCR management unit was operating under the detection monitoring program in § 257.94 or the assessment monitoring program in § 257.95;

(iii) * * *

(B) Provide the date when the assessment monitoring program was initiated for the CCR unit or the CCR management unit.

(iv) * * *

(B) Provide the date when the assessment monitoring program was initiated for the CCR unit or the CCR management unit.

(C) Provide the date when the public meeting was held for the assessment of corrective measures for the CCR unit or the CCR management unit; and

(D) Provide the date when the assessment of corrective measures was completed for the CCR unit or the CCR management unit.

* * * * *

(f) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

* * * * *

■ 11. Amend § 257.91 by revising paragraphs (a) introductory text, (a)(1) introductory text, (a)(1)(i), (a)(2), (c)(2), (d), (e)(1), and (g) to read as follows:

§ 257.91 Groundwater monitoring systems.

(a) Performance standard. The owner or operator of a CCR unit or a CCR management unit must install a groundwater monitoring system that consists of a sufficient number of wells, installed at appropriate locations and depths, to yield groundwater samples from the uppermost aquifer that:

(1) Accurately represent the quality of background groundwater that has not been affected by leakage from a CCR unit or a CCR management unit. A determination of background quality may include sampling of wells that are not hydraulically upgradient of the CCR management area where:

(i) Hydrogeologic conditions do not allow the owner or operator of the CCR unit or the CCR management unit to

determine what wells are hydraulically upgradient; or

* * * * *

(2) Accurately represent the quality of groundwater passing the waste boundary of the CCR unit or the CCR management unit. The downgradient monitoring system must be installed at the waste boundary that ensures detection of groundwater contamination in the uppermost aquifer. All potential contaminant pathways must be monitored.

* * * * *

(c) * * *

(2) Additional monitoring wells as necessary to accurately represent the quality of background groundwater that has not been affected by leakage from the CCR unit or the CCR management unit and the quality of groundwater passing the waste boundary of the CCR unit or the CCR management unit.

(d) The owner or operator of multiple CCR units or CCR management units may install a multiunit groundwater monitoring system instead of separate groundwater monitoring systems for each CCR unit or CCR management unit.

(1) The multiunit groundwater monitoring system must be equally as capable of detecting monitored constituents at the waste boundary of the CCR unit or CCR management unit as the individual groundwater monitoring system specified in paragraphs (a) through (c) of this section for each CCR unit or CCR management unit based on the following factors:

(i) Number, spacing, and orientation of each CCR unit or CCR management unit;

(ii) Hydrogeologic setting;

(iii) Site history; and

(iv) Engineering design of the CCR unit or CCR management unit.

(2) [Reserved]

(e) * * *

(1) The owner or operator of the CCR unit or the CCR management unit must document and include in the operating record the design, installation, development, and decommissioning of any monitoring wells, piezometers and other measurement, sampling, and analytical devices. The qualified professional engineer must be given access to this documentation when completing the groundwater monitoring system certification required under paragraph (f) of this section.

* * * * *

(g) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

■ 12. Amend § 257.93 by revising paragraphs (a) introductory text, (c), (d), (f) introductory text, (f)(6), (g)(1), (h), and (j) to read as follows:

§ 257.93 Groundwater sampling and analysis requirements.

(a) The groundwater monitoring program must include consistent sampling and analysis procedures that are designed to ensure monitoring results that provide an accurate representation of groundwater quality at the background and downgradient wells required by § 257.91. The owner or operator of the CCR unit or the CCR management unit must develop a sampling and analysis program that includes procedures and techniques for:

* * * * *

(c) Groundwater elevations must be measured in each well immediately prior to purging, each time groundwater is sampled. The owner or operator of the CCR unit or the CCR management unit must determine the rate and direction of groundwater flow each time groundwater is sampled. Groundwater elevations in wells which monitor the same CCR management area must be measured within a period of time short enough to avoid temporal variations in groundwater flow which could preclude accurate determination of groundwater flow rate and direction.

(d) The owner or operator of the CCR unit or the CCR management unit must establish background groundwater quality in a hydraulically upgradient or background well(s) for each of the constituents required in the particular groundwater monitoring program that applies to the CCR unit as determined under § 257.94(a) or § 257.95(a). Background groundwater quality may be established at wells that are not located hydraulically upgradient from the CCR unit or the CCR management unit if it meets the requirements of § 257.91(a)(1).

* * * * *

(f) The owner or operator of the CCR unit or the CCR management unit must select one of the statistical methods specified in paragraphs (f)(1) through (5) of this section to be used in evaluating groundwater monitoring data for each specified constituent. The statistical test chosen shall be conducted separately for each constituent in each monitoring well.

* * * * *

(6) The owner or operator of the CCR unit or the CCR management unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority stating that the

selected statistical method is appropriate for evaluating the groundwater monitoring data for the CCR management area. The certification must include a narrative description of the statistical method selected to evaluate the groundwater monitoring data.

(g) * * *

(1) The statistical method used to evaluate groundwater monitoring data shall be appropriate for the distribution of constituents. Normal distributions of data values shall use parametric methods. Non-normal distributions shall use non-parametric methods. If the distribution of the constituents is shown by the owner or operator of the CCR unit or the CCR management unit to be inappropriate for a normal theory test, then the data must be transformed or a distribution-free (non-parametric) theory test must be used. If the distributions for the constituents differ, more than one statistical method may be needed.

* * * * *

(h) The owner or operator of the CCR unit or the CCR management unit must determine whether or not there is a statistically significant increase over background values for each constituent required in the particular groundwater monitoring program that applies to the CCR unit or the CCR management unit, as determined under § 257.94(a) or § 257.95(a).

* * * * *

(j) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h).

■ 13. Amend § 257.94 by revising paragraphs (a), (b) and (f) to read as follows:

§ 257.94 Detection monitoring program.

(a) The owner or operator of a CCR unit or a CCR management unit must conduct detection monitoring at all groundwater monitoring wells consistent with this section. At a minimum, a detection monitoring program must include groundwater monitoring for all constituents listed in appendix III to this part.

(b) Except as provided in paragraph (d) of this section, the monitoring frequency for the constituents listed in appendix III to this part shall be at least semiannual during the active life of the CCR unit or the CCR management unit and the post-closure period. For existing CCR landfills and existing CCR surface impoundments, a minimum of eight

independent samples from each background and downgradient well must be collected and analyzed for the constituents listed in appendix III and IV to this part no later than October 17, 2017. For new CCR landfills, new CCR surface impoundments, and all lateral expansions of CCR units, a minimum of eight independent samples for each background well must be collected and analyzed for the constituents listed in appendices III and IV to this part during the first six months of sampling. For CCR management units, a minimum of eight independent samples from each background and downgradient well must be collected and analyzed for the constituents listed in appendix III and IV to this part no later than 24 months after effective date of the final rule.

* * * * *

(f) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h). ■ 14. Amend § 257.95 by revising paragraphs (b), (e), (g) introductory text, (g)(1) introductory text, the first sentence of (g)(3)(ii), paragraphs (g)(4), (h) introductory text, and (i) to read as follows:

§ 257.95 Assessment monitoring program.

* * * * *

(b)(1) Within 90 days of triggering an assessment monitoring program, and annually thereafter:

(i) The owner or operator of the CCR unit must sample and analyze the groundwater for all constituents listed in appendix IV to this part.

(ii) The owner or operator of a CCR management unit must sample and analyze the groundwater for all constituents listed in appendix IV to this part no later than 24 months after effective date of the final rule.

(2) The number of samples collected and analyzed for each well during each sampling event must be consistent with § 257.93(e) and must account for any unique characteristics of the site, but must be at least one sample from each well.

* * * * *

(e) If the concentrations of all constituents listed in appendices III and IV to this part are shown to be at or below background values, using the statistical procedures in § 257.93(g), for two consecutive sampling events, the owner or operator may return to detection monitoring of the CCR unit or the CCR management unit. The owner or operator must prepare a notification

stating that detection monitoring is resuming for the CCR unit or the CCR management unit. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(7).

* * * * *

(g) If one or more constituents in appendix IV to this part are detected at statistically significant levels above the groundwater protection standard established under paragraph (h) of this section in any sampling event, the owner or operator must prepare a notification identifying the constituents in appendix IV to this part that have exceeded the groundwater protection standard. The owner or operator has completed the notification when the notification is placed in the facility's operating record as required by § 257.105(h)(8). The owner or operator of the CCR unit or the CCR management unit also must:

(1) Characterize the nature and extent of the release and any relevant site conditions that may affect the remedy ultimately selected. The characterization must be sufficient to support a complete and accurate assessment of the corrective measures necessary to effectively clean up all releases from the CCR unit or the CCR management unit pursuant to § 257.96. Characterization of the release includes the following minimum measures:

* * * * *

(3) * * *

(ii) Demonstrate that a source other than the CCR unit or the CCR management unit caused the contamination, or that the statistically significant increase resulted from error in sampling, analysis, statistical evaluation, or natural variation in groundwater quality. * * *

(4) If a successful demonstration has not been made at the end of the 90 day period provided by paragraph (g)(3)(ii) of this section, the owner or operator of the CCR unit or the CCR management unit must initiate the assessment of corrective measures requirements under § 257.96.

* * * * *

(h) The owner or operator of the CCR unit or the CCR management unit must establish a groundwater protection standard for each constituent in appendix IV to this part detected in the groundwater. The groundwater protection standard shall be:

* * * * *

(i) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h),

the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h). ■ 15. Amend § 257.96 by revising paragraphs (a), (b), and (f) to read as follows:

§ 257.96 Assessment of corrective measures.

(a) Within 90 days of finding that any constituent listed in Appendix IV to this part has been detected at a statistically significant level exceeding the groundwater protection standard defined under § 257.95(h), or immediately upon detection of a release from a CCR unit or a CCR management unit, the owner or operator must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area to original conditions.

(b) The owner or operator of the CCR unit or the CCR management unit must continue to monitor groundwater in accordance with the assessment monitoring program as specified in § 257.95.

* * * * *

(f) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h). ■ 16. Amend § 257.97 by revising paragraphs (c) introductory text, (d) introductory text, and (e) to read as follows:

§ 257.97 Selection of remedy.

* * * * *

(c) In selecting a remedy that meets the standards of paragraph (b) of this section, the owner or operator of the CCR unit or the CCR management unit shall consider the following evaluation factors:

* * * * *

(d) The owner or operator must specify as part of the selected remedy a schedule(s) for implementing and completing remedial activities. Such a schedule must require the completion of remedial activities within a reasonable period of time taking into consideration the factors set forth in paragraphs (d)(1) through (6) of this section. The owner or operator of the CCR unit or the CCR management unit must consider the following factors in determining the schedule of remedial activities:

* * * * *

(e) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified

in § 257.106(h), and the internet requirements specified in § 257.107(h).

■ 17. Amend § 257.98 by revising paragraphs (a)(3) introductory text, (b), (c)(1), and (f) to read as follows:

§ 257.98 Implementation of the corrective action program.

(a) * * *

(3) Take any interim measures necessary to reduce the contaminants leaching from the CCR unit or the CCR management unit, and/or potential exposures to human or ecological receptors. Interim measures must, to the greatest extent feasible, be consistent with the objectives of and contribute to the performance of any remedy that may be required pursuant to § 257.97. The following factors must be considered by an owner or operator in determining whether interim measures are necessary:

* * * * *

(b) If an owner or operator of the CCR unit or the CCR management unit, determines, at any time, that compliance with the requirements of § 257.97(b) is not being achieved through the remedy selected, the owner or operator must implement other methods or techniques that could feasibly achieve compliance with the requirements.

(c) * * *

(1) The owner or operator of the CCR unit or the CCR management unit demonstrates compliance with the groundwater protection standards established under § 257.95(h) has been achieved at all points within the plume of contamination that lie beyond the groundwater monitoring well system established under § 257.91.

* * * * *

(f) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(h), the notification requirements specified in § 257.106(h), and the internet requirements specified in § 257.107(h). ■ 18. Amend § 257.100 by revising the section heading and paragraph (a), and adding paragraph (f) to read as follows:

§ 257.100 Inactive CCR surface impoundments and Legacy CCR surface impoundments.

(a) Inactive CCR surface impoundments and legacy CCR surface impoundments are subject to all of the requirements of this subpart applicable to existing CCR surface impoundments.

* * * * *

(f) *Timeframes for legacy CCR surface impoundments—(1) Legacy CCR surface impoundment applicability documentation.* (i) Excepted as provided in paragraph (f)(1)(ii) of this

section, owners and operators of legacy CCR surface impoundments must prepare documentation for each legacy CCR surface impoundment subject to the requirements of this subpart no later than the date the final rule is effective. At a minimum, the documentation for each legacy CCR surface impoundment must contain:

(A) Information to identify the legacy CCR surface impoundment and delineate the unit boundaries, including a figure of the facility and where the unit is located at the facility.

(B) The name associated with the legacy CCR surface impoundment.

(C) The identification number of the legacy CCR surface impoundment if one has been assigned by the state.

(D) Size of the legacy CCR surface impoundment (in acres).

(E) A description of the current site conditions, including the current use of the inactive facility.

(F) The proximity (in feet, or miles, if appropriate) of the legacy CCR surface impoundment to the closest surface water body.

(G) The name and address of the person(s) owning and operating the legacy CCR surface impoundment with their phone number and email address.

(H) The owner or operator of the legacy CCR surface impoundment must notify the Agency of the establishment of the facility's CCR website and the applicability of the rule, using the procedures in § 257.107(a) via the "contact us" form on EPA's CCR website.

(ii) For owners and operators of legacy CCR surface impoundments that completed closure of the CCR unit by removal of waste prior to the effective date of the final rule, no later than the effective date of the final rule, complete a closure certification documenting that all closure requirements in § 257.102(c) have been met.

(2) *Design criteria.* The owner or operator of a legacy CCR surface impoundment must:

(i) Except for legacy CCR surface impoundments that are incised, no later than the date the final rule is effective, place on or immediately adjacent to the CCR unit the permanent identification marker as set forth by § 257.73(a)(1).

(ii) Except for legacy CCR surface impoundments that do not exceed the height and/or storage volume thresholds under § 257.73(b), no later than three months after the date the final rule is effective, compile a history of construction as set forth by § 257.73(c).

(iii) Except for legacy CCR surface impoundments that are incised, no later than three months after the date the final rule is effective, complete the

initial hazard potential classification assessment as set forth by § 257.73(a)(2) and (f).

(iv) Except for legacy CCR surface impoundments that do not exceed the height and/or storage volume thresholds under § 257.73(b), no later than three months after the date the final rule is effective, complete the structural stability and safety factor assessments as set forth by § 257.73(d), (e), and (f).

(v) Except for legacy CCR surface impoundments that are incised, no later than nine months after the date the final rule is effective, prepare and maintain an Emergency Action Plan as set forth by § 257.73(a)(3).

(3) *Operating criteria.* The owner or operator of the legacy CCR surface impoundment must:

(i) No later than the date the final rule is effective, prepare the initial CCR fugitive dust control plan as set forth in § 257.80(b).

(ii) No later than the date the final rule is effective, initiate the inspections by a qualified person as set forth by § 257.83(a).

(iii) No later than the date the final rule is effective, prevent the unknowing entry, and minimize the possibility for the unauthorized entry, of persons or livestock onto the legacy CCR surface impoundment.

(iv) No later than three months after the date the final rule is effective, complete the initial annual inspection by a qualified professional engineer as set forth by § 257.83(b).

(v) No later than nine months after the date the final rule is effective, prepare the initial inflow design flood control system plan as set forth in § 257.82(c).

(vi) No later than 12 months after the date the final rule is effective, prepare the initial annual fugitive dust control report as set forth in § 257.80(c).

(4) *Groundwater monitoring and corrective action.* The owner or operator of the legacy CCR surface impoundment must:

(i) No later than six months after the date the final rule is effective, install the groundwater monitoring system as required by § 257.91.

(ii) No later than six months after the date the final rule is effective, develop the groundwater sampling and analysis program, including the selection of the statistical procedures, that will be used for evaluating groundwater monitoring data as required by § 257.93.

(iii) No later than 24 months after the date the final rule is effective, be in compliance with the following groundwater monitoring requirements:

(A) Initiate the detection monitoring program to include obtaining a minimum of eight independent samples

for each background and downgradient well, as required by § 257.94(b).

(B) Begin evaluating the groundwater monitoring data for statistically significant increases over background levels for the constituents listed in appendix III of this part, as required by § 257.94.

(C) Begin evaluating the groundwater monitoring data for statistically significant levels over groundwater protection standards for the constituents listed in appendix IV of this part as required by § 257.95.

(iv) No later than January 31 of the year after the groundwater monitoring system is established, prepare the initial groundwater monitoring and corrective action report as set forth in § 257.90(e).

(5) *Closure and post-closure care.* The owner or operator of the legacy CCR surface impoundment must:

(i) No later than 12 months after the date the final rule is effective, prepare an initial written closure plan as set forth in § 257.102(b); and

(ii) No later than 12 months after the date the final rule is effective, prepare an initial written post-closure care plan as set forth in § 257.104(d).

■ 19. Amend § 257.101 by adding paragraphs (e) and (f) to read as follows:

§ 257.101 Closure or retrofit of CCR units and CCR management units.

* * * *

(e) The owner or operator of a legacy CCR surface impoundment is subject to the requirements of paragraphs (e)(1) and (2) of this section.

(1) No later than 12 months after the date the final rule is effective, an owner or operator of a legacy CCR surface impoundment must initiate the closure of the legacy CCR surface impoundment in accordance with the requirements of § 257.102.

(2) An owner or operator of a legacy CCR surface impoundment that closes in accordance with paragraph (e)(1) of this section must include a statement in the notification required under § 257.102(g) that the legacy CCR surface impoundment is closing under the requirement of paragraph (e)(1) of this section.

(f) The owner or operator of a CCR management unit is subject to the requirements of paragraphs (f)(1) and (2) of this section.

(1) No later than 12 months after the date the final rule is effective, an owner or operator of a CCR management unit must initiate the closure of the CCR management unit in accordance with the requirements of § 257.102.

(2) An owner or operator of a CCR management unit that closes in accordance with paragraph (f)(1) of this

section must include a statement in the notification required under § 257.102(g) that the CCR management unit is closing under the requirements of paragraph (f)(1) of this section.

■ 20. Amend § 257.102 by:

■ a. Revising paragraphs (a), (b)(1), and (b)(2)(iii);

■ b. Adding paragraph (b)(2)(iv);

■ c. Revising paragraphs (b)(3)(ii)(A), (b)(3)(iii), (b)(4), (c), (d)(1) introductory text, (d)(1)(iv), (d)(2) introductory text, (d)(3) introductory text, (d)(3)(i)(B), (d)(3)(iii), (e) introductory text, and (f)(1) introductory text;

■ d. Adding paragraph (f)(1)(iii); and

■ e. Revising paragraphs (f)(2)(i) introductory text, (f)(2)(i)(B), and (C);

■ f. Adding paragraphs (f)(2)(ii)(D) and (E); and

■ g. Revising paragraphs (f)(2)(iii), (f)(3), (g), (h), (i)(1), (i)(2)(i), (i)(4), and (j).

The revisions and additions read as follows:

§ 257.102 Criteria for conducting the closure or retrofit of CCR units and closure of CCR management units.

(a) Closure of a CCR landfill, CCR surface impoundment, any lateral expansion of a CCR unit, or a CCR management unit must be completed either by leaving the CCR in place and installing a final cover system or through removal of the CCR and decontamination of the CCR unit or CCR management unit, as described in paragraphs (b) through (j) of this section. Retrofit of a CCR surface impoundment must be completed in accordance with the requirements in paragraph (k) of this section.

(b) * * *

(1) *Content of the plan.* The owner or operator of a CCR unit or a CCR management unit must prepare a written closure plan that describes the steps necessary to close the CCR unit or the CCR management unit at any point during the active life of the CCR unit or CCR management unit consistent with recognized and generally accepted good engineering practices. The written closure plan must include, at a minimum, the information specified in paragraphs (b)(1)(i) through (vi) of this section.

(i) A narrative description of how the CCR unit or CCR management unit will be closed in accordance with this section.

(ii) If closure of the CCR unit or CCR management unit will be accomplished through removal of CCR from the CCR unit or CCR management unit, a description of the procedures to remove the CCR and decontaminate the CCR unit or CCR management unit in accordance with paragraph (c) of this section.

(iii) If closure of the CCR unit or CCR management unit will be accomplished by leaving CCR in place, a description of the final cover system, designed in accordance with paragraph (d) of this section, and the methods and procedures to be used to install the final cover. The closure plan must also discuss how the final cover system will achieve the performance standards specified in paragraph (d) of this section.

(iv) An estimate of the maximum inventory of CCR ever on-site over the active life of the CCR unit or CCR management unit.

(v) An estimate of the largest area of the CCR unit or CCR management unit ever requiring a final cover as required by paragraph (d) of this section at any time during the CCR unit's active life.

(vi) A schedule for completing all activities necessary to satisfy the closure criteria in this section, including an estimate of the year in which all closure activities for the CCR unit or CCR management unit will be completed.

The schedule should provide sufficient information to describe the sequential steps that will be taken to close the CCR unit or CCR management unit, including identification of major milestones such as coordinating with and obtaining necessary approvals and permits from other agencies, the dewatering and stabilization phases of CCR surface impoundment or CCR management unit closure, or installation of the final cover system, and the estimated timeframes to complete each step or phase of CCR unit or CCR management unit closure. When preparing the written closure plan, if the owner or operator of a CCR unit or CCR management unit estimates that the time required to complete closure will exceed the timeframes specified in paragraph (f)(1) of this section, the written closure plan must include the site-specific information, factors and considerations that would support any time extension sought under paragraph (f)(2) of this section.

(2) * * *

(iii) *CCR management units.* No later than 12 months after effective date of the final rule, the owner or operator of the CCR management unit must prepare an initial written closure plan consistent with the requirements specified in paragraph (b)(1) of this section.

(iv) The owner or operator has completed the written closure plan when the plan, including the certification required by paragraph (b)(4) of this section, has been placed in the facility's operating record as required by § 257.105(i)(4).

(3) * * *

(ii) * * *

(A) There is a change in the operation of the CCR unit or CCR management unit that would substantially affect the written closure plan in effect; or

* * * * *

(iii) The owner or operator must amend the closure plan at least 60 days prior to a planned change in the operation of the facility, CCR unit, or CCR management unit or no later than 60 days after an unanticipated event requires the need to revise an existing written closure plan. If a written closure plan is revised after closure activities have commenced for a CCR unit or a CCR management unit, the owner or operator must amend the current closure plan no later than 30 days following the triggering event.

(4) The owner or operator of the CCR unit or the CCR management unit must obtain a written certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the initial and any amendment of the written closure plan meets the requirements of this section.

(c) *Closure by removal of CCR.* An owner or operator may elect to close a CCR unit or a CCR management unit by removing and decontaminating all areas affected by releases from the CCR unit or the CCR management unit. CCR removal and decontamination of the CCR unit or CCR management unit are complete when constituent concentrations throughout the CCR unit or the CCR management unit and any areas affected by releases from the CCR unit or CCR management unit have been removed and groundwater monitoring concentrations do not exceed the groundwater protection standard established pursuant to § 257.95(h) for constituents listed in appendix IV to this part.

(d) * * *

(1) *General performance standard.* The owner or operator of a CCR unit or CCR management unit must ensure that, at a minimum, the CCR unit or CCR management unit is closed in a manner that will:

* * * * *

(iv) Minimize the need for further maintenance of the CCR unit or the CCR management unit; and

* * * * *

(2) *Drainage and stabilization of CCR units and CCR management units.* The owner or operator of any CCR unit or CCR management unit must meet the requirements of paragraphs (d)(2)(i) and (ii) of this section prior to installing the

final cover system required under paragraph (d)(3) of this section.

* * * * *

(3) *Final cover system.* If a CCR unit or CCR management unit is closed by leaving CCR in place, the owner or operator must install a final cover system that is designed to minimize infiltration and erosion, and at a minimum, meets the requirements of paragraph (d)(3)(i) of this section, or the requirements of the alternative final cover system specified in paragraph (d)(3)(ii) of this section.

(i) * * *

(B) The infiltration of liquids through the closed CCR unit or CCR management unit must be minimized by the use of an infiltration layer that contains a minimum of 18 inches of earthen material.

* * * * *

(iii) The owner or operator of the CCR unit or the CCR management unit must obtain a written certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the permitting authority that the design of the final cover system meets the requirements of this section.

(e) *Initiation of closure activities.* Except as provided for in paragraph (e)(4) of this section and § 257.103, the owner or operator of a CCR unit must commence closure of the CCR unit no later than the applicable timeframes specified in either paragraph (e)(1) or (2) of this section. CCR management units are subject to the requirements of paragraph (e)(3) of this section.

* * * * *

(f) * * *

(1) Except as provided for in paragraph (f)(2) of this section, the owner or operator must complete closure of the CCR unit or the CCR management unit:

* * * * *

(iii) For CCR management units, within five years of commencing closure activities.

(2) * * *

(i) *Extensions of closure timeframes.* The timeframes for completing closure of a CCR unit or a CCR management unit specified under paragraphs (f)(1) of this section may be extended if the owner or operator can demonstrate that it was not feasible to complete closure of the CCR unit or the CCR management unit within the required timeframes due to factors beyond the facility's control. If the owner or operator is seeking a time extension beyond the time specified in the written closure plan as required by paragraph (b)(1) of this section, the demonstration must include a narrative

discussion providing the basis for additional time beyond that specified in the closure plan. The owner or operator must place each completed demonstration, if more than one time extension is sought, in the facility's operating record as required by § 257.105(i)(6) prior to the end of any two-year period. Factors that may support such a demonstration include:

* * * * *

(B) Time required to dewater a surface impoundment or a CCR management unit due to the volume of CCR contained in the CCR unit or the characteristics of the CCR in the unit;

(C) The geology and terrain surrounding the CCR unit or the CCR management unit will affect the amount of material needed to close the CCR unit or the CCR management unit; or

* * * * *

(ii) * * *

(D) CCR management units of 40 acres or smaller may extend the time to complete closure by no longer than two years.

(E) CCR management units larger than 40 acres may extend the timeframe to complete closure of the CCR management unit multiple times, in two-year increments. For each two-year extension sought, the owner or operator must substantiate the factual circumstances demonstrating the need for the extension. No more than a total of five two-year extensions may be obtained for any CCR management unit.

(iii) In order to obtain additional time extension(s) to complete closure of a CCR unit or a CCR management unit beyond the times provided by paragraph (f)(1) of this section, the owner or operator of the CCR unit or the CCR management unit must include with the demonstration required by paragraph (f)(2)(i) of this section the following statement signed by the owner or operator or an authorized representative:

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this demonstration and all attached documents, and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

(3) Upon completion, the owner or operator of the CCR unit or the CCR management unit must obtain a certification from a qualified professional engineer or approval from the Participating State Director or approval from EPA where EPA is the

permitting authority verifying that closure has been completed in accordance with the closure plan specified in paragraph (b) of this section and the requirements of this section.

(g) No later than the date the owner or operator initiates closure of a CCR unit or CCR management unit, the owner or operator must prepare a notification of intent to close a CCR unit or CCR management unit. The notification must include the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority for the design of the final cover system as required by § 257.102(d)(3)(iii), if applicable. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(7).

(h) Within 30 days of completion of closure of the CCR unit or CCR management unit, the owner or operator must prepare a notification of closure of a CCR unit or CCR management unit. The notification must include the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority as required by § 257.102(f)(3). The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(8).

(i) * * *

(1) Except as provided by paragraph (i)(4) of this section, following closure of a CCR unit or CCR management unit, the owner or operator must record a notation on the deed to the property, or some other instrument that is normally examined during title search.

(2) * * *

(i) The land has been used as a CCR unit or CCR management unit; and

(4) An owner or operator that closes a CCR unit or CCR management unit in accordance with paragraph (c) of this section is not subject to the requirements of paragraphs (i)(1) through (3) of this section.

(j) The owner or operator of the CCR unit or CCR management unit must comply with the closure recordkeeping requirements specified in § 257.105(i), the closure notification requirements specified in § 257.106(i), and the closure internet requirements specified in § 257.107(i).

* * * * *

■ 21. Amend § 257.104 by revising paragraphs (a), (b) introductory text,

(b)(2), (c), (d)(1), (2), (d)(3)(ii)(A), (d)(3)(iii), (d)(4), (e), and (f) to read as follows:

§ 257.104 Post-closure care requirements.

(a) *Applicability.* (1) Except as provided by paragraph (a)(2) of this section, § 257.104 applies to the owners or operators of CCR landfills, CCR surface impoundments, all lateral expansions of CCR units, and CCR management units that are subject to the closure criteria under § 257.102.

(2) An owner or operator of a CCR unit or a CCR management unit that elects to close a CCR unit or a CCR management unit by removing CCR as provided by § 257.102(c) is not subject to the post-closure care criteria under this section.

(b) *Post-closure care maintenance requirements.* Following closure of the CCR unit or the CCR management unit, the owner or operator must conduct post-closure care for the CCR unit or the CCR management unit, which must consist of at least the following:

* * * * *

(2) If the CCR unit or the CCR management unit is subject to the design criteria under § 257.70, maintaining the integrity and effectiveness of the leachate collection and removal system and operating the leachate collection and removal system in accordance with the requirements of § 257.70; and

* * * * *

(c) *Post-closure care period.* (1) Except as provided by paragraph (c)(2) of this section, the owner or operator of the CCR unit or the CCR management unit must conduct post-closure care for 30 years.

(2) If at the end of the post-closure care period the owner or operator of the CCR unit or the CCR management unit is operating under assessment monitoring in accordance with § 257.95, the owner or operator must continue to conduct post-closure care until the owner or operator returns to detection monitoring in accordance with § 257.95.

(d) * * *

(1) *Content of the plan.* The owner or operator of a CCR unit or a CCR management unit must prepare a written post-closure plan that includes, at a minimum, the information specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) A description of the monitoring and maintenance activities required in paragraph (b) of this section for the CCR unit or the CCR management unit, and the frequency at which these activities will be performed;

(ii) The name, address, telephone number, and email address of the

person or office to contact about the facility during the post-closure care period; and

(iii) A description of the planned uses of the property during the post-closure period. Post-closure use of the property shall not disturb the integrity of the final cover, liner(s), or any other component of the containment system, or the function of the monitoring systems unless necessary to comply with the requirements in this subpart. Any other disturbance is allowed if the owner or operator of the CCR unit or the CCR management unit demonstrates that disturbance of the final cover, liner, or other component of the containment system, including any removal of CCR, will not increase the potential threat to human health or the environment. The demonstration must be certified by a qualified professional engineer or approved by the Participating State Director or approved from EPA where EPA is the permitting authority, and notification shall be provided to the State Director that the demonstration has been placed in the operating record and on the owners or operator's publicly accessible internet site.

(2) *Deadline to prepare the initial written post-closure plan—*(i) *Existing CCR landfills and existing CCR surface impoundments.* No later than October 17, 2016, the owner or operator of the CCR unit must prepare an initial written post-closure plan consistent with the requirements specified in paragraph (d)(1) of this section.

(ii) *New CCR landfills, new CCR surface impoundments, and any lateral expansion of a CCR unit.* No later than the date of the initial receipt of CCR in the CCR unit, the owner or operator must prepare an initial written post-closure plan consistent with the requirements specified in paragraph (d)(1) of this section.

(iii) *CCR Management Units.* No later than 12 months after effective date of the final rule, the owner or operator of a CCR management unit must prepare an initial written post-closure care plan as set forth in paragraph (d)(1) of this section.

(iv) The owner or operator has completed the written post-closure plan when the plan, including the certification required by paragraph (d)(4) of this section, has been placed in the facility's operating record as required by § 257.105(i)(4).

(3) * * *

(ii) * * *

(A) There is a change in the operation of the CCR unit or the CCR management unit that would substantially affect the written post-closure plan in effect; or

* * * * *

(iii) The owner or operator must amend the written post-closure plan at least 60 days prior to a planned change in the operation of the facility or CCR unit, or CCR management unit, or no later than 60 days after an unanticipated event requires the need to revise an existing written post-closure plan. If a written post-closure plan is revised after post-closure activities have commenced for a CCR unit or a CCR management unit, the owner or operator must amend the written post-closure plan no later than 30 days following the triggering event.

(4) The owner or operator of the CCR unit or the CCR management unit must obtain a written certification from a qualified professional engineer or an approval from the Participating State Director or an approval from EPA where EPA is the permitting authority that the initial and any amendment of the written post-closure plan meets the requirements of this section.

(e) Notification of completion of post-closure care period. No later than 60 days following the completion of the post-closure care period, the owner or operator of the CCR unit or the CCR management unit must prepare a notification verifying that post-closure care has been completed. The notification must include the certification by a qualified professional engineer or the approval from the Participating State Director or the approval from EPA where EPA is the permitting authority verifying that post-closure care has been completed in accordance with the closure plan specified in paragraph (d) of this section and the requirements of this section. The owner or operator has completed the notification when it has been placed in the facility's operating record as required by § 257.105(i)(13).

(f) The owner or operator of the CCR unit or the CCR management unit must comply with the recordkeeping requirements specified in § 257.105(i), the notification requirements specified in § 257.106(i), and the internet requirements specified in § 257.107(i).

■ 22. Amend § 257.105 by:

■ a. Revising paragraphs (a), (b), (c), (d), and (f) introductory text;

■ b. Adding paragraph (f)(25);

■ c. Revising paragraphs (g) introductory text, (h) introductory text, (i) introductory text, (i)(7), and (8); and

■ d. Adding paragraph (k).

The revisions and additions read as follows:

§ 257.105 Recordkeeping requirements.

(a) *Operating Record.* Each owner or operator of a CCR unit or CCR management unit subject to the

requirements of this subpart must maintain files of all information required by this section in a written operating record at their facility.

(b) *Document Retention.* Unless specified otherwise, each file must be retained for at least five years following the date of each occurrence, measurement, maintenance, corrective action, report, record, or study.

(c) *Recordkeeping for multiple CCR units or CCR management units.* An owner or operator of more than one CCR unit or CCR management unit subject to the provisions of this subpart may comply with the requirements of this section in one recordkeeping system provided the system identifies each file by the name of each CCR unit. The files may be maintained on microfilm, on a computer, on computer disks, on a storage system accessible by a computer, on magnetic tape disks, or on microfiche.

(d) *State Director and/or appropriate Tribal authority notification.* The owner or operator of a CCR unit or CCR management unit must submit to the State Director and/or appropriate Tribal authority any demonstration or documentation required by this subpart, if requested, when such information is not otherwise available on the owner or operator's publicly accessible internet site.

* * * * *

(f) *Design criteria.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

* * * * *

(25) The Facility Evaluation Report as required by § 257.75(c).

(g) *Operating criteria.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

* * * * *

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

* * * * *

(i) *Closure and post-closure care.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

* * * * *

(7) The notification of intent to close a CCR unit or CCR management unit as required by § 257.102(g).

(8) The notification of completion of closure of a CCR unit or CCR management unit as required by § 257.102(h).

* * * * *

(k) *Legacy CCR surface impoundments.* In addition to the information specified in paragraphs (e) through (j) of this section, the owner or operator of a legacy CCR surface impoundment subject to this subpart must place the following information, as it becomes available, in the facility's operating record:

(1) The applicability documentation required by § 257.100(f)(1)(i).

(2) The completion of closure by removal certification as specified under § 257.100(f)(1)(ii).

■ 23. Amend § 257.106 by:

■ a. Revising paragraphs (a), (b), (c), (d), and (f) introductory text;

■ b. Adding paragraph (f)(24);

■ c. Revising paragraphs (g) introductory text, (h) introductory text, (h)(5), (i) introductory text, (i)(7), and (8); and

■ d. Adding paragraph (k).

The revisions and additions read as follows:

§ 257.106 Notification requirements.

(a) *Deadline to submit notification to the relevant State Director and/or appropriate Tribal authority.* The notifications required under paragraphs (e) through (i) of this section must be sent to the relevant State Director and/or appropriate Tribal authority before the close of business on the day the notification is required to be completed. For purposes of this section, *before the close of business* means the notification must be postmarked or sent by electronic mail (email). If a notification deadline falls on a weekend or federal holiday, the notification deadline is automatically extended to the next business day.

(b) *Notifications to Tribal authority.* If any CCR unit or CCR management unit is located in its entirety within Indian Country, the notifications of this section must be sent to the appropriate Tribal authority. If any CCR unit or CCR management unit is located in part within Indian Country, the notifications of this section must be sent both to the appropriate State Director and Tribal authority.

(c) *Combining notifications.* Notifications may be combined as long as the deadline requirement for each notification is met.

(d) *Notification deadline after placement in operating record.* Unless

otherwise required in this section, the notifications specified in this section must be sent to the State Director and/or appropriate Tribal authority within 30 days of placing in the operating record the information required by § 257.105.

* * * * *

(f) *Design criteria.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

* * * * *

(24) Provide notification of the availability of the Facility Evaluation Report as specified by § 257.105(f)(25).

(g) *Operating criteria.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

* * * * *

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

* * * * *

(5) Provide notification that the CCR unit or CCR management unit is returning to a detection monitoring program specified under § 257.105(h)(7).

* * * * *

(i) *Closure and post-closure care.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

* * * * *

(7) Provide notification of intent to close a CCR unit or CCR management unit specified under § 257.105(i)(7).

(8) Provide notification of completion of closure of a CCR unit or CCR management unit specified under § 257.105(i)(8).

* * * * *

(k) *Legacy CCR surface impoundments.* In addition to the information specified in paragraphs (e) through (j) of this section, the owner or operator of a legacy CCR surface impoundment subject to this subpart must notify the State Director and/or appropriate Tribal authority when information has been placed in the operating record and on the owner or operator's publicly accessible internet site. The owner or operator must:

(1) Provide notification of the availability of the applicability documentation as specified under § 257.105(k)(1).

(2) Provide notification of the availability of the completion of closure by removal certification as specified under § 257.105(k)(2).

■ 24. Amend § 257.107 by:

- a. In paragraph (a) adding a paragraph heading and revising the first sentence;
- b. Revising paragraphs (b), (c), (d), and (f) introductory text;
- c. Adding paragraph (f)(24);
- d. Revising paragraphs (g) introductory text, (h) introductory text and (h)(5);
- e. Revising paragraphs (i) introductory text, (i)(7), and (8); and
- f. Adding paragraph (k).

The revisions and additions read as follows:

§ 257.107 Publicly accessible internet site requirements.

(a) *CCR website requirement.* Each owner or operator of a CCR unit or CCR management unit subject to the requirements of this subpart must maintain a publicly accessible internet site (CCR website) containing the information specified in this section.

* * *

(b) *CCR website for multiple units.* An owner or operator of more than one CCR unit or CCR management unit subject to the provisions of this subpart may comply with the requirements of this section by using the same CCR website for multiple CCR units or CCR management units provided the CCR website clearly delineates information by the name or identification number of each unit.

(c) *Document retention on a CCR website.* Unless otherwise required in this section, the information required to be posted to the CCR website must be made available to the public for at least five years following the date on which the information was first posted to the CCR website.

(d) *Website posting deadline after placement in operating record.* Unless

otherwise required in this section, the information must be posted to the CCR website within 30 days of placing the pertinent information required by § 257.105 in the operating record.

* * * * *

(f) *Design criteria.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information on the owner or operator's CCR website:

* * * * *

(24) The Facility Evaluation Report as specified under § 257.105(f)(25).

(g) *Operating criteria.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information on the owner or operator's CCR website:

* * * * *

(h) *Groundwater monitoring and corrective action.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information on the owner or operator's CCR website:

* * * * *

(5) The notification that the CCR unit or CCR management unit is returning to a detection monitoring program specified under § 257.105(h)(7).

* * * * *

(i) *Closure and post-closure care.* The owner or operator of a CCR unit or CCR management unit subject to this subpart must place the following information on the owner or operator's CCR website:

* * * * *

(7) The notification of intent to close a CCR unit or CCR management unit specified under § 257.105(i)(7).

(8) The notification of completion of closure of a CCR unit or CCR management unit specified under § 257.105(i)(8).

* * * * *

(k) *Legacy CCR surface impoundments.* In addition to the information specified in paragraphs (e) through (j) of this section, the owner or operator of a legacy CCR surface impoundment subject to this subpart must place the following information on the owner or operator's CCR website:

(1) The applicability documentation as specified under § 257.105(k)(1).

(2) The completion of closure by removal certification as specified under § 257.105(k)(2).

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Part V

Department of Housing and Urban Development

Allocations for Community Development Block Grant Disaster Recovery and
Implementation of the CDBG-DR Consolidated Waivers and Alternative
Requirements Notice; Notice

**DEPARTMENT OF HOUSING AND
URBAN DEVELOPMENT**
[Docket No. FR-6393-N-01]
**Allocations for Community
Development Block Grant Disaster
Recovery and Implementation of the
CDBG-DR Consolidated Waivers and
Alternative Requirements Notice**
AGENCY: Office of the Assistant
Secretary for Community Planning and
Development, HUD.

ACTION: Notice.

SUMMARY: In March 2023, HUD allocated more than \$3 billion in Community Development Block Grant Disaster Recovery (CDBG-DR) funds appropriated by the Continuing Appropriations Act, 2023 and the Department of Housing and Urban Development Appropriations Act, 2023 for major disasters occurring in 2022. This Allocation Announcement Notice identifies grant requirements for these funds, including requirements in HUD's CDBG-DR Consolidated Notice ("Consolidated Notice") found in Appendix B, and a limited number of amendments to the Consolidated Notice that apply to CDBG-DR grants for disasters occurring in 2020, 2021, and 2022. The Consolidated Notice, as amended by this Allocation Announcement Notice, includes waivers and alternative requirements, relevant regulatory requirements, the grant award process, criteria for action plan approval, and eligible disaster recovery activities.

DATES: *Applicability Date:* May 23, 2023.

FOR FURTHER INFORMATION CONTACT: Tennille Smith Parker, Director, Office of Disaster Recovery, Department of Housing and Urban Development, 451 7th Street SW, Room 7282, Washington, DC 20410, telephone number 202-708-3587 (this is not a toll-free number). HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech or communication disabilities. To learn more about how to make an accessible

telephone call, please visit: <https://www.fcc.gov/consumers/guides/telecommunications-relay-service-trs>. Facsimile inquiries may be sent to Ms. Parker at 202-708-0033 (this is not a toll-free number). Email inquiries may be sent to disaster_recovery@hud.gov.

SUPPLEMENTARY INFORMATION:
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I. Allocations

The Continuing Appropriations Act, 2023 (Pub. L. 117-180, Division A) approved September 30, 2022, makes available \$2,000,000,000 in CDBG-DR funds. These CDBG-DR funds are for necessary expenses for activities authorized under title I of the Housing and Community Development Act of 1974 (42 U.S.C. 5301 *et seq.*) (HCDA) related to disaster relief, long-term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation in the "most impacted and distressed" (MID) areas resulting from a qualifying major disaster in 2021 or 2022. Additionally, the Department of Housing and Urban Development Appropriations Act, 2023 (Pub. L. 117-328, Division L, Title II) approved December 29, 2022, makes available \$3,000,000,000 in CDBG-DR funds for major disasters that occurred in 2022 or later until such funds are fully allocated. This notice announces allocations of \$3,391,220,000 from Public Laws 117-180 and 117-328 (collectively, the "Appropriations Acts") for disasters occurring in 2022. The Appropriations Acts require HUD

to include with any final allocation for the total estimate of unmet need an additional amount of 15 percent of that estimate for mitigation activities that reduce risk in the MID areas (see Table 1).

The Appropriations Acts provide that grants shall be awarded directly to a state, local government, or Indian tribe at the discretion of the Secretary.

Pursuant to the Appropriations Acts, HUD has identified MID areas based on the best available data for all eligible affected areas. A detailed explanation of HUD's allocation methodology is provided in Appendix A of this notice. To comply with requirements that all funds are expended in MID areas, Lee County, Florida; Volusia County, Florida; Orange County, Florida; Sarasota County, Florida; St. Clair County, Illinois; St. Louis County, Missouri; and St. Louis City, Missouri must use 100 percent of the total funds allocated to address unmet disaster needs or mitigation activities within the HUD-identified MID areas identified in the last column in Table 2.

All other grantees must use at least 80 percent of their allocations to address unmet disaster needs or mitigation activities in the HUD-identified MID areas, as identified in the last column of Table 2. These grantees may use the remaining 20 percent of their allocation to address unmet disaster needs or mitigation activities in those areas that the grantee determines are "most impacted and distressed" within an area that received a Presidential major disaster declaration identified by the Federal Emergency Management Agency (FEMA) disaster numbers listed in column two of Table 1. However, these grantees are not precluded from spending 100 percent of their allocation in the HUD-identified MID areas if they choose to do so. Detailed requirements related to MID areas are provided in section II.A.3. of the Consolidated Notice.

Based on a review of the impacts from the eligible disasters, and estimates of unmet need, HUD made the following allocations for disasters occurring in 2022:

TABLE 1—ALLOCATIONS FOR UNMET NEEDS AND MITIGATION ACTIVITIES UNDER PUBLIC LAW 117-180 AND 117-328 FOR DISASTERS OCCURRING IN 2022

Year	FEMA disaster No.	State	Grantee	Allocation for unmet needs from Public Law 117-180	CDBG-DR mitigation set-aside amounts from Public Law 117-180	Allocation for unmet needs from Public Law 117-328	CDBG-DR mitigation set-aside amounts from Public Law 117-328	Total allocated under this notice from Public Law 117-180 and 117-328
2022	4672	Alaska	State of Alaska	\$0	\$0	\$33,472,000	\$5,021,000	\$38,493,000
2022	4673	Florida	Lee County	0	0	963,375,000	144,506,000	1,107,881,000
2022	4673	Florida	Volusia County	0	0	286,009,000	42,901,000	328,910,000

TABLE 1—ALLOCATIONS FOR UNMET NEEDS AND MITIGATION ACTIVITIES UNDER PUBLIC LAW 117–180 AND 117–328 FOR DISASTERS OCCURRING IN 2022—Continued

Year	FEMA disaster No.	State	Grantee	Allocation for unmet needs from Public Law 117–180	CDBG–DR mitigation set-aside amounts from Public Law 117–180	Allocation for unmet needs from Public Law 117–328	CDBG–DR mitigation set-aside amounts from Public Law 117–328	Total allocated under this notice from Public Law 117–180 and 117–328
2022	4673	Florida	Orange County	0	0	191,054,000	28,658,000	219,712,000
2022	4673	Florida	Sarasota County ..	0	0	175,248,000	26,287,000	201,535,000
2022	4673	Florida	State of Florida	0	0	791,847,000	118,777,000	910,624,000
2022	4676	Illinois	St. Clair County	0	0	26,110,000	3,917,000	30,027,000
2022	4663	Kentucky	State of Kentucky ..	259,125,000	38,869,000	0	0	297,994,000
2022	4665	Missouri	St. Louis County	49,065,000	7,360,000	0	0	56,425,000
2022	4665	Missouri	St. Louis City	22,464,000	3,370,000	0	0	25,834,000
2022	4657 & 4670	Oklahoma	State of Oklahoma ..	6,498,000	975,000	0	0	7,473,000
2022	4649 & 4671	Commonwealth of Puerto Rico.	Commonwealth of Puerto Rico.	144,039,000	21,606,000	580,000	87,000	166,312,000
Totals				481,191,000	72,180,000	2,467,695,000	370,154,000	3,391,220,000

Note: Grantees in Kentucky, Missouri, and Oklahoma are funded under PL 117–180; the grant for Puerto Rico is split \$165,645,000 under PL 117–180 and \$667,000 under PL 117–328; Grantees in Alaska, Florida, and Illinois are funded completely under PL 117–328. The Oklahoma allocation is based on both a county and tribal geography because declarations include both a tribal area and counties.

TABLE 2—MOST IMPACTED AND DISTRESSED AREAS FOR DISASTERS OCCURRING IN 2022

Grantee	Minimum amount from Public Law 117–180 that must be expended in the HUD-identified “most impacted and distressed” areas in column 4	Minimum amount from Public Law 117–328 that must be expended in the HUD-identified “most impacted and distressed” areas in column 4	“Most impacted and distressed” areas
State of Alaska	\$0	\$30,794,400	Bering Strait Regional Education, Lower Yukon Regional Education; 99563 (Kashunamiut Regional Education).
Lee County	0	1,107,881,000	Lee County.
Volusia County	0	328,910,000	Volusia County.
Orange County	0	219,712,000	Orange County.
Sarasota County	0	201,535,000	Sarasota County.
State of Florida	0	728,499,200	Brevard, Charlotte, Collier, DeSoto, Hardee, Highlands, Hillsborough, Manatee, Monroe, Osceola, Pinellas, Polk, Seminole Counties; 32177 (Putnam County).
St. Clair County	0	30,027,000	St. Clair County.
State of Kentucky	238,395,200	0	Breathitt, Knott, Letcher, Perry Counties; 41572 (Pike County).
St. Louis County	56,425,000	0	St. Louis County.
St. Louis City	25,834,000	0	St. Louis City.
State of Oklahoma	5,978,400	0	Muscogee (Creek) OTSA/74447 (Okmulgee County).
Commonwealth of Puerto Rico.	132,516,000	533,600	Salinas Municipio; 00610 (Anasco Municipio), 00612 (Arecibo Municipio), 00794 (Barranquitas Municipio), 00623 (Cabo Rojo Municipio), 00725 (Caguas Municipio), 00729 (Canovanas Municipio), 00646 (Dorado Municipio), 00784 (Guayama Municipio), 00660 (Hormigueros Municipio), 00791 (Humacao Municipio), 00795 (Juana Diaz Municipio), 00667 (Lajas Municipio), 00771 (Las Piedras Municipio), 00719 (Naranjito Municipio), 00720 (Orocovis Municipio), 00728 (Ponce Municipio), 00754 (San Lorenzo Municipio), 00757 (Santa Isabel Municipio), 00949 (Toa Baja Municipio), 00693 (Vega Baja Municipio), 00767 (Yabucoa Municipio), 00698 (Yauco Municipio).

II. Use of Funds

Funds for disasters occurring in 2022 announced in this notice are subject to the requirements of this Allocation Announcement Notice and the Consolidated Notice, included as Appendix B, as amended. HUD makes amendments to the Consolidated Notice in this Allocation Announcement Notice to reflect the terms of the

Appropriations Acts. However, the Consolidated Notice in Appendix B is the same Consolidated Notice included as Appendix B in previous Allocation Announcements Notices published in the **Federal Register** (87 FR 6364, 87 FR 31636, and 88 FR 3198). Sections III.A.1, III.A.1.a, and III.A.1.b of this Allocation Announcement Notice include instructions for a grantee

submitting an early action plan for program administrative costs and will replace the alternative requirement in the Consolidated Notice at III.C.1 for purposes of accessing funds for program administrative costs prior to the Secretary’s certification.

To comply with the statutory requirement in the Appropriations Acts, grantees shall not use CDBG–DR funds

for activities reimbursable by or for which funds are made available by FEMA or the U.S. USACE of Engineers (USACE). Grantees must verify whether FEMA or USACE funds are available prior to awarding CDBG–DR funds to specific activities or beneficiaries. Grantees may use CDBG–DR funds as the non-Federal match as described in section II.C.3 of the Consolidated Notice.

II.A. Allocations of CDBG–DR Funds for Smaller Grants

Paragraph III.C.1.b of the Consolidated Notice requires that CDBG–DR action plans “demonstrate a reasonably proportionate allocation of resources relative to areas and categories (i.e., housing, economic revitalization, and infrastructure) of greatest needs identified in the grantee’s impact and unmet needs assessment or provide an acceptable justification for a disproportional allocation.” Additionally, paragraph III.C.1.g of the Consolidated Notice requires grantees to “provide a budget for the full amount of the allocation that is reasonably proportionate to its unmet needs (or provide an acceptable justification for disproportional allocation) and is consistent with the requirements to integrate hazard mitigation measures into all its programs and projects.”

HUD recognizes that grantees receiving a relatively small allocation of funds for 2022 disasters in this notice may most effectively advance recovery by more narrowly targeting these limited recovery and mitigation resources. Accordingly, for grantees receiving an allocation of less than \$20 million for 2022 disaster(s) announced in this notice, HUD will consider the small size of the grant and HUD’s allocation methodology as acceptable justification for a grantee to propose a disproportional allocation when the grantee is allocating funds to address unmet affordable rental housing needs caused by or exacerbated by the disaster(s). Grantees exercising this option must continue to comply with the applicable requirements of this notice and the Consolidated Notice, including the CDBG–DR mitigation set-aside requirement in section IV.A.2 of this notice.

III. Overview of Grant Process

III.A. Requirements Related to Administrative Funds

III.A.1. Action plan submittal for program administrative costs. The Appropriations Acts allow grantees receiving an award under this notice to access funding for program

administrative costs prior to the Secretary’s certification of financial controls and procurement processes, and adequate procedures for proper grant management. To implement this authority, the following alternative requirement will replace the alternative requirement in the Consolidated Notice at III.C.1.

If a grantee chooses to access funds for program administrative costs prior to the Secretary’s certification, it must first prepare an action plan describing its use of funds for program administrative costs, subject to the five percent cap on the use of grant funds for such costs. Instead of following requirements in section III.C.1 of the Consolidated Notice, which require grantees to use the Public Action Plan in HUD’s DRGR system to submit their action plans, grantees will follow a different process to access funds for program administrative costs prior to the Secretary’s certification.

As part of the process of accessing funds for these costs, grantees must submit to HUD an action plan describing their use of funds for program administrative costs. The action plan will be developed outside of DRGR and must include all proposed uses of funds for program administrative costs incurred prior to a final action plan being submitted and approved. The action plan for program administrative costs must also include the criteria for eligibility and the amount to be budgeted for that activity. If a grantee chooses to submit the action plan for program administrative costs, the grantee should calculate its need to cover program administrative costs over the life of the grant and consider how much of its available program administrative funds may be reasonably budgeted at this very early stage of its grant lifecycle.

III.A.1.a. Publication of the action plan for program administrative costs and opportunity for public comment. The grantee must publish the proposed action plan for program administrative costs, and substantial amendments to the plan, for public comment. To permit a more streamlined process and ensure that grants for program administrative costs are awarded in a timely manner in order to allow grantees to more rapidly design and launch recovery activities, provisions of 42 U.S.C. 5304(a)(2) and (3), 42 U.S.C. 12707, 24 CFR 570.486, 24 CFR 1003.604, 24 CFR 91.105(b) through (d), and 24 CFR 91.115(b) through (d), with respect to citizen participation requirements, are waived and replaced by the alternative requirements in section III.A.1 that apply only to action plans for program

administrative costs and substantial amendments to these plans. Additionally, for these action plans only, grantees are not subject to the Consolidated Notice action plan requirements in sections III.B.2.i, III.C.2, III.C.3, III.C.6, and III.D.1.a–c.

The manner of publication of the action plan for program administrative costs must include prominent posting on the grantee’s official disaster recovery website and must afford residents, affected local governments, and other interested parties a reasonable opportunity to review the contents of the plan or substantial amendment. Subsequent to publication of the action plan or substantial amendment to that plan, the grantee must provide a reasonable time frame (no less than seven days) and multiple methods (including electronic submission) for receiving comments on the action plan or substantial amendment for program administrative costs. At a minimum, the topic of disaster recovery on the grantee’s website, including the posted action plan or substantial amendment, must be navigable by interested parties from the grantee homepage and must link to the disaster recovery website as required by section III.D.1.e of the Consolidated Notice. The grantee’s records must demonstrate that it has notified affected parties through electronic mailings, press releases, statements by public officials, media advertisements, public service announcements, and/or contacts with neighborhood organizations. Grantees are not required to hold any public hearings on the proposed action plan or substantial amendment for program administrative costs.

The grantee must consider all oral and written comments on the action plan or any substantial amendment. Any updates or changes made to the action plan in response to public comments should be clearly identified in the action plan. A summary of comments on the plan or amendment, and the grantee’s response to each, must be included with the action plan or substantial amendment. Grantee responses shall address the substance of the comment rather than merely acknowledge that the comment was received.

After the grantee responds to public comments, it will then submit its action plan or substantial amendment for program administrative costs (which includes Standard Form 424 (SF–424)) to HUD for approval. There is no due date for this plan as it may be submitted any time prior to the grantee’s Public Action Plan. HUD will review the action plan or substantial amendment for

program administrative costs within 15 days from date of receipt and determine whether to approve the action plan or substantial amendment to that plan per the criteria identified in this notice.

III.A.1.b. Certifications waiver and alternative requirement. Sections 104(b)(4), (c), and (m) of the HCDA (42 U.S.C. 5304(b)(4), (c), and (m)), sections 106(d)(2)(C) and (D) of the HCDA (42 U.S.C. 5306(d)(2)(C) and (D)), and section 106 of the Cranston-Gonzalez National Affordable Housing Act (42 U.S.C. 12706), and regulations at 24 CFR 91.225 and 91.325 are waived and replaced with the following alternative. Each grantee choosing to submit an action plan for program administrative costs must make the following certifications listed in section III.F.7 of the Consolidated Notice and include them with the submission of this plan: paragraphs b, c, d, g, i, j, k, l, p, and q. Additionally, HUD is waiving section 104(a)–(c) and (d)(1) of the HCDA (42 U.S.C. 5304), section 106(c)(1) and (d) of the HCDA (42 U.S.C. 5306), section 210 of the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970 (URA) (42 U.S.C. 4630), section 305 of the URA (42 U.S.C. 4655), and regulations at 24 CFR 91.225(a)(2), (6), and (7), 91.225(b)(7), 91.325(a)(2), (6), and (7), 49 CFR 24.4(a), and 24 CFR 42.325 only to the extent necessary to allow grantees to receive a portion of their allocation as a grant for program administrative costs before submitting other statutorily required certifications. Each grantee must make all certifications included in section III.F.7 of the Consolidated Notice and submit them to HUD when it submits its Public Action Plan in DRGR described in III.C.1.

III.A.1.c. Submission of the action plan for program administrative costs in DRGR. After HUD's approval of the action plan for program administrative costs, the grantee enters the activities from its approved action plan into the DRGR system if it has not previously done so and submits its DRGR action plan to HUD (funds can be drawn from the line of credit only for activities that are established in the DRGR system). HUD has previously provided additional guidance ("Fact Sheet") with screenshots and step-by-step instructions describing the submittal process for this DRGR action plan for program administrative costs.¹ This process will allow a grantee to access

funds for program administrative costs while the grantee begins developing its Public Action Plan in DRGR as provided in section III.C.1 of the Consolidated Notice.

III.A.1.d. Incorporation of the action plan for program administrative costs into the Public Action Plan. The grantee shall describe the use of all grant funds for administrative costs in the Public Action Plan required by section III.C.1. Use of grant funds for administrative costs before approval of the Public Action Plan must be consistent with the action plan for administrative costs. Once the Public Action Plan is approved, the use of all grant funds must be consistent with the Public Action Plan. Upon HUD's approval of the Public Action Plan, the action plan for administrative costs shall only be relevant to administrative costs charged to the grant before the date of approval of the Public Action Plan.

III.A.2. Use of administrative funds across multiple grants. The Appropriations Acts authorize special treatment of grant administrative funds. Grantees that are receiving awards under this notice, and that have received CDBG–DR or Community Development Block Grant mitigation (CDBG–MIT) grants in the past or in any future acts, may use eligible administrative funds (up to five percent of each grant award plus up to five percent of program income generated by the grant) appropriated by these acts for the cost of administering any CDBG–DR or CDBG–MIT grant without regard to the particular disaster appropriation from which such funds originated. If the grantee chooses to exercise this authority, the grantee must have appropriate financial controls to comply with the requirement that the amount of grant administration expenditures for each CDBG–DR or CDBG–MIT grant will not exceed five percent of the total grant award for each grant (plus five percent of program income generated by the grant), review and modify its financial management policies and procedures regarding the tracking and accounting of administration costs, as necessary, and address the adoption of this treatment of administrative costs in the applicable portions of its Financial Management and Grant Compliance submissions as referenced in section III.A.1 of the Consolidated Notice. Grantees are reminded that all uses of funds for program administrative activities must qualify as an eligible administration cost.

IV. Applicable Rules, Statutes, Waivers, and Alternative Requirements

The Appropriations Acts authorize the Secretary to waive or specify alternative requirements for any provision of any statute or regulation that the Secretary administers in connection with the obligation by the Secretary, or use by the recipient, of these funds, except for requirements related to fair housing, nondiscrimination, labor standards, and the environment. This section of the notice and the Consolidated Notice describe rules, statutes, waivers, and alternative requirements that apply to allocations under this notice. For each waiver and alternative requirement in this notice and incorporated through the Consolidated Notice, the Secretary has determined that good cause exists, and the waiver or alternative requirement is not inconsistent with the overall purpose of title I of the HCDA. The waivers and alternative requirements provide flexibility in program design and implementation to support full and swift recovery following eligible disasters, while ensuring that statutory requirements are met.

Grantees may request additional waivers and alternative requirements from the Department as needed to address specific needs related to their recovery and mitigation activities. Grantees should work with the assigned CPD representative to request any additional waivers or alternative requirements from HUD headquarters. The waivers and alternative requirements described below apply to all grantees under this notice. Under the requirements of the Appropriations Acts, waivers and alternative requirements are effective five days after they are published in the **Federal Register** or on the website of the Department.

IV.A. Grant Administration

IV.A.1. Duplication of Benefits (DOB). Grantees that received funds for disasters occurring in 2022 must follow the requirements located in section IV.A. of the Consolidated Notice and the DOB requirements described in this section. The **Federal Register** notice published on June 2019, titled "Updates to Duplication of Benefits Requirements Under the Stafford Act for Community Development Block Grant (CDBG) Disaster Recovery Grantees" (84 FR 28836) ("2019 DOB Notice"), revised the DOB requirements that apply to CDBG–DR grants for disasters declared between January 1, 2016, and December 31, 2021. For these disasters, the 2019 DOB Notice also implemented

¹ The Fact Sheet describing the process to submit an action plan for program administrative costs in DRGR can be viewed at <https://files.hudexchange.info/resources/documents/DRGR-Fact-Sheet-PL117-43-Appropriation-Grantees.pdf>.

temporary changes to the treatment of loans made by the Disaster Recovery Reform Act of 2018 (DRRA) (division D of Pub. L. 115–254), which sunsets on October 5, 2023.

This DRRA loan exception does not apply to disasters occurring in 2022, therefore, subsidized loans may be a duplication of benefits for CDBG–DR grants announced in this notice (depending on a grantee’s DOB analysis). Without the DRRA loan exception, most subsidized loans duplicate CDBG–DR funds for the same purpose (there are limited exceptions for declined, cancelled, or subsidized short-term loans to pay for eligible costs before CDBG–DR funds became available, as described in section IV.A.1. of the Consolidated Notice). Therefore, HUD’s time-limited policy in the 2019 DOB Notice to permit reimbursement of costs paid with the proceeds of subsidized loans does not apply after the DRRA loan exception sunsets. Additionally, because the DRRA loan exception never applied to disasters occurring in 2022 or later, grantees receiving CDBG–DR funds for those disasters are not able to reimburse the costs paid by subsidized loans, including SBA loans, unless the exceptions in section IV.A.1.a. of the Consolidated Notice applies. These grantees must follow the duplication of benefits requirements described below and in section IV.A. of the Consolidated Notice.

This section of the notice describes the applicable laws and requirements related to DOB, including the general framework to calculate DOB. Section IV.A. of the Consolidated Notice describes the exceptions for when a subsidized loan that is cancelled or declined is not considered a duplication of benefits.

IV.A.1.(a). The Stafford Act. The Robert T. Stafford Disaster Relief and Emergency Assistance Act (42 U.S.C. 5121–5207) (Stafford Act) is the primary legal authority establishing the framework for the Federal government to provide disaster and emergency assistance.

Section 312 of the Stafford Act directs Federal agencies that provide disaster assistance to assure that people, businesses, or other entities do not receive financial assistance that duplicates any part of their disaster loss covered by insurance or another source (42 U.S.C. 5155(a)). Section 312 also makes recipients of Federal disaster assistance liable for repayment of the amount of Federal disaster assistance that duplicates benefits available for the same purpose from another source (42 U.S.C. 5155(c)).

The Stafford Act also provides that when assistance covers only a part of the recipient’s disaster needs, additional assistance to cover needs not met by other sources will not cause a DOB (42 U.S.C. 5155(b)(3)). CDBG–DR assistance may only pay for eligible activities to address unmet needs. This section advises grantees on the calculation of unmet needs through a duplication of benefits analysis.

IV.A.1.(b). CDBG–DR Appropriations Acts and Federal Register Notices. CDBG–DR funds are made available for “necessary expenses” by the Appropriations Acts that contain statutory requirements on the use of the grant funds. Grantees are subject to the requirements of the Appropriations Acts, this notice, and the Consolidated Notice.

Since 2013, as a condition of making any CDBG–DR grant, the Secretary must certify that the grantee has established adequate procedures to prevent DOB. To meet this requirement, grantees must submit DOB policies to HUD for review before HUD will award non-administrative funds. “Adequate” procedures are those that meet the requirements that HUD established in this notice, in the Consolidated Notice, and as reflected in the related checklists that are available online. HUD requires grantees to establish DOB policies that incorporate certain steps before committing or awarding assistance. Typically, the steps include determining the total need for assistance, verifying the total assistance available from all sources of disaster assistance (using recent data available from FEMA, SBA, and other sources), excluding non-duplicative assistance from total assistance to calculate DOB, reducing the total award by the amount of the DOB, and obtaining an agreement from applicants to repay duplicative assistance.

This notice and the Consolidated Notice also require CDBG–DR grantees to consider projected sources of disaster assistance in the needs assessment that is part of an action plan for disaster recovery. Consideration of other potential sources of assistance when planning for the use of grant funds helps to limit the possibility of duplication between CDBG–DR and other assistance.

IV.A.1.(c). Necessary and Reasonable Requirements. The Uniform Administrative Requirements, Cost Principles, and Audit Requirements for Federal Awards in subpart E of 2 CFR part 200 (the Cost Principles) applicable to all CDBG–DR grantees and their subrecipients require that costs are necessary and reasonable. The Cost Principles are made applicable to states

by 24 CFR 570.489(p) and to local governments through 24 CFR 570.502. State grantees are also subject to 24 CFR 570.489(d), which requires that states shall have fiscal and administrative requirements to ensure that grant funds are used “for reasonable and necessary costs of operating programs.”

Under the Cost Principles, a cost assigned to a grant “is reasonable if, in its nature and amount, it does not exceed that which would be incurred by a prudent person under the circumstances prevailing at the time the decision was made to incur the cost” (2 CFR 200.404).

Grantees must consider factors described at 2 CFR 200.404(a) through (e) when determining which types and amounts of cost items are necessary and reasonable. Based on these factors, HUD generally presumes that if a cost has been paid by another source, charging it to the Federal award violates the necessary and reasonable standard unless grant requirements permit reimbursement.

IV.A.1.(d). Basic Duplication of Benefits Calculation Framework. The Stafford Act requires a fact specific inquiry into assistance received by each applicant. This notice refers to the subject of a DOB review as an “applicant” or “CDBG–DR applicant” and uses the term “applicant” to include individuals, businesses, households, or other entities that apply to the grantee or a subrecipient for CDBG–DR assistance, as well as entities that use CDBG–DR assistance for an activity without submitting an application (e.g., the department or agency of the grantee administering the grant, other state or local departments or agencies, or local governments).

A grantee is prohibited from making a blanket determination that CDBG–DR assistance under one of its programs or activities does not duplicate another category or source of assistance. The grantee must conduct an individualized review of each applicant to determine that the amount of assistance will not cause a DOB by exceeding the unmet needs of that applicant. A review specific to each applicant is necessary because assistance available to each applicant varies widely based on individual insurance coverage, eligibility for various sources of assistance, and other factors.

This section establishes the primary considerations that must be part of a DOB analysis when providing CDBG–DR assistance, and a framework for analyzing need and avoiding DOB when calculating awards. CDBG–DR grantees have discretion to develop policies and procedures that tailor their DOB

analyses to their own programs and activities so long as the grantee's policies and procedures are consistent with the requirements of this notice. If the grantee modifies its DOB procedures after the Secretary certifies that the grantee's DOB procedures are adequate, the grantee's modified procedures must meet standards HUD adopts to determine adequacy.

IV.A.1.(d)(i). Assess Applicant Need.

A grantee must determine an applicant's total need. Total need is calculated based on need estimates at a point in time; total need is the current need. However, if the grantee's action plan permits CDBG-DR assistance to reimburse costs of CDBG-DR eligible activities undertaken by the applicant before submitting an application the total need also includes these costs. Generally, total need is calculated without regard to the grantee's program-specific caps on the amount of assistance.

For rehabilitation, reconstruction, or new construction activities, the need can be reasonably documented using construction cost estimates.

For recovery programs of the grantee that do not entail physical rebuilding, such as special economic development activities to provide an affected business with working capital, the total need will be determined by the requirements or parameters of the program or activity. For special economic development activities, total need should be guided by standard underwriting guidelines (when required by section II.D.6. of the Consolidated Notice, CDBG-DR grantees and subrecipients must comply with the underwriting guidelines in Appendix A to 24 CFR part 570 when assisting a for-profit entity as part of a special economic development project).

The grantee's assessment of total need must consider in-kind donations of materials or services that are known to the grantee at the time it calculates need and makes the award. In-kind donations are non-cash contributions, such as donations of professional services, use of construction equipment, or contributions of building materials. In-kind donations are not "financial assistance" that creates a DOB under the Stafford Act, but they do reduce the amount of CDBG-DR assistance for unmet need because the donated goods or services reduce activity costs.

IV.A.1.(d)(ii). Identify Total Assistance. To calculate DOB, grantees are required to identify "total assistance." For this notice, total assistance includes all reasonably identifiable financial assistance available to an applicant.

Total assistance includes resources such as cash awards, insurance proceeds, grants, and loans received by or available to each CDBG-DR applicant, including awards under local, state or Federal programs, and from private or nonprofit charity organizations. At a minimum, the grantee's efforts to identify total assistance must include a review to determine whether the applicant received FEMA, SBA, insurance, and any other major forms of assistance (e.g., state disaster assistance programs) generally available to applicants.

Total assistance does not include personal assets such as money in a checking or savings account (excluding insurance proceeds or disaster assistance deposited into the applicant's account); retirement accounts; credit cards and lines of credit; in-kind donations (although these non-cash contributions known to the grantee reduce total need); and private loans.

For this notice, a private loan is a loan that is not provided by or guaranteed by a governmental entity, and that requires the CDBG-DR applicant (the borrower) to repay the full amount of the loan (principal and interest) under typical commercial lending terms, e.g., the loan is not forgivable. For DOB calculations, private loans are not financial assistance and need not be considered in the DOB calculation, regardless of whether the borrower is a person or entity.

By contrast, subsidized loans for the same purpose are to be included in the DOB calculation unless an exception applies (see sections IV.A.1.a. or IV.A.1.b. of the Consolidated Notice).

Total assistance includes available assistance. Assistance is available if an applicant: (1) would have received it by acting in a reasonable manner, or in other words, by taking the same practical steps toward funding recovery as would disaster survivors faced with the same situation but not eligible to receive CDBG-DR assistance; or (2) has received the assistance and has legal control over it. Available assistance includes reasonably anticipated assistance that has been awarded and accepted but has not yet been received. For example, if a local government seeks CDBG-DR assistance to fund part of a project that also has been awarded FEMA Hazard Mitigation Grant Program (HMGP) assistance, the entire HMGP award must be included in the calculation of total assistance even if FEMA obligates the first award increment for the project, but subsequent increments remain unfunded until certain project milestones are met.

Applicants for CDBG-DR assistance are expected to seek insurance or other assistance to which they are legally entitled under existing policies and contracts, and to behave reasonably when negotiating payments to which they may be entitled. For example, it may be reasonable for an applicant to elect to receive an immediate lump sum insurance settlement based on estimated cost of rehabilitation instead of waiting for a longer period of time for the insurance company to calculate reimbursement based on actual replacement costs, even if the reimbursement based on actual costs would exceed the lump sum insurance settlement.

HUD generally considers assistance to be available if it is awarded to the applicant but is administered by another party instead of being directly deposited with the applicant. For example, if an entity administering homeowner rehabilitation assistance pays a contractor directly to complete the rehabilitation, the assistance is still considered available to the applicant.

By contrast, funds that are not available to an applicant must be excluded from the final CDBG-DR award calculation. For example, insurance or rehabilitation assistance received by a previous owner of a disaster damaged housing unit is not available to a current owner that acquired the unit by sale or transfer (including a current owner that inherited the unit as a result of the death of the previous owner) unless the current owner is a co-recipient of that assistance.

Funds are not available to an applicant if the applicant does not have legal control of the funds when they are received. For example, if a homeowner's mortgage requires insurance proceeds to be applied to reduce the unpaid mortgage principal, then the lender/mortgage holder (not the homeowner) has legal control over those funds. The homeowner is legally obligated to use insurance proceeds for the purpose of reducing the unpaid mortgage principal and does not have a choice in using them for any other purpose, such as to rehabilitate the house. Under these circumstances, insurance proceeds do not reduce CDBG-DR rehabilitation assistance eligibility.

Alternatively, if a lender requires use of insurance for rehabilitation, or a disaster-affected homeowner chooses to apply insurance proceeds received for damage to the building to reduce an unpaid mortgage principal, these insurance proceeds are treated as a DOB and reduce the amount of CDBG-DR

funds the grantee may provide for rehabilitation.

IV.A.1.(d)(iii). Exclude Non-Duplicative Amounts. Once a grantee has determined the total need and the total assistance, it determines which sources it must exclude as non-duplicative for the DOB calculation. Grantees must exclude amounts that are: (1) provided for a different purpose; or (2) provided for the same purpose (eligible activity), but for a different, allowable use (cost). Below, each of these categories is explained in greater detail.

IV.A.1.(d)(iii)(1). Funds for a Different Purpose. Any assistance provided for a different purpose than the CDBG-DR eligible activity, or a general, non-specific purpose (e.g., “disaster relief/recovery”) and not used for the same purpose must be excluded from total assistance when calculating the amount of the DOB.

Insurance proceeds for damage or destruction of a building are for the same purpose as CDBG-DR assistance to rehabilitate or reconstruct that building. On the other hand, grantees may exclude, as non-duplicative, insurance provided for a different purpose (e.g., insurance proceeds for loss of contents and personal property, or insurance proceeds for loss of buildings (such as a detached garage) that the grantee has determined it will not assist with CDBG-DR funds). However, a grantee may treat all insurance proceeds as duplicative if it is impractical to identify the portion of insurance proceeds that are non-duplicative because they are for a different purpose than the CDBG-DR assistance.

Similarly, CDBG-DR assistance paid to a homeowner as a housing incentive for the purpose of inducing the homeowner to sell the home to the grantee (e.g., in conjunction with a buyout) are for a different purpose than funds provided for interim housing (e.g., temporary assistance for rental housing during a period when a household is unable to reside in its home). In such a case, interim housing assistance may be excluded from the final DOB calculation as non-duplicative of funds paid for the housing incentive.

IV.A.1.(d)(iii)(2). Funds for Same Purpose, Different Allowable Use. Assistance provided for the same purpose as the CDBG-DR purpose (the CDBG-DR eligible activity) must be excluded when calculating the amount of the DOB if the applicant can document that actual specific use of the assistance was an allowable use of that assistance and was different than the use (cost) of the CDBG-DR assistance (e.g., the purpose is housing

rehabilitation, the use of the other assistance was roof replacement and the use of the CDBG-DR assistance is rehabilitation of the interior of the house). Grantees are advised to consult with HUD to determine what documentation is appropriate in this circumstance. As a starting point, grantees should consider whether the source of the assistance requires beneficiaries to maintain documentation of how the assistance was used.

Whether the use of the non-CDBG-DR assistance is an allowable use depends on the rules imposed by the source that provided the assistance. For example, assume that a CDBG-DR grantee is administering a homeowner rehabilitation program and an applicant to the program can document that he/she previously received and used FEMA funds for interim housing costs (i.e., rent). If FEMA permitted the applicant to use its assistance for the general purpose of meeting any housing need, the CDBG-DR grantee can exclude the FEMA assistance used for interim housing as non-duplicative of the CDBG-DR assistance for rehabilitation.

If, on the other hand, FEMA limited the use of FEMA funds to housing rehabilitation, then the full amount of the FEMA assistance must be considered for the specific purpose of housing rehabilitation and cannot be excluded if the applicant used those funds for interim housing. If interim housing is not an allowable use, the amount of the FEMA housing rehabilitation assistance used for interim housing is considered a DOB. If the grantee thinks the actual use of the FEMA assistance may be allowable, the CDBG-DR grantee should contact FEMA for clarification.

Assistance provided for the purpose of housing rehabilitation, including assistance provided for temporary or minor rehabilitation, is for the same purpose as CDBG-DR rehabilitation assistance. However, the grantee can exclude assistance used for different costs of the rehabilitation, which are a different allowable use (rehabilitation costs not assisted with CDBG-DR). For example, if the other assistance is used for minor or temporary rehabilitation which enabled the applicant family to live in their home instead of moving to temporary housing until rehabilitation can be completed, the grantee can undertake remaining work necessary to complete rehabilitation. The grantee's assessment of total need at the time of application may include the costs of replacing temporary materials with permanent construction and of completing mold remediation by removing drywall installed with other

assistance. These types of costs to modify partially completed rehabilitation that the grantee determines are necessary to comply with the requirements of CDBG-DR assistance do not duplicate other assistance used for the partial rehabilitation.

Grantees are encouraged to contact HUD for further guidance in cases when it is unclear whether non-CDBG-DR assistance for the same general purpose can be excluded from the DOB calculation because it was used for a different allowable use.

IV.A.1.(d)(iv). Identify DOB Amount and Calculate the Total CDBG-DR Award. The total DOB is calculated by subtracting non-duplicative exclusions from total assistance. Therefore, to calculate the total maximum amount of the CDBG-DR award, the grantee must: (1) identify total need; (2) identify total assistance; (3) subtract exclusions from total assistance to determine the amount of the DOB; and (4) subtract the amount of the DOB from the amount of the total need to determine the maximum amount of the CDBG-DR award.

Three considerations may change the maximum amount of the CDBG-DR award.

First, the grantee may impose a program cap that limits the amount of assistance an applicant is eligible to receive, which may reduce the potential CDBG-DR assistance available to the applicant.

Second, the grantee may increase the amount of an award if the applicant agrees to repay duplicative assistance it receives in the future (unless prohibited by a statutory order of assistance, as in the requirement to use FEMA or USACE assistance before CDBG-DR assistance discussed in sections II. and IV.A.1.(f)). Section 312(b) of the Stafford Act permits a grantee to provide CDBG-DR assistance to an applicant who is or may be entitled to receive assistance that would be duplicative if: (1) the applicant has not received the other assistance at the time the CDBG-DR grantee makes its award; and (2) the applicant agrees to repay the CDBG-DR grantee for any duplicative assistance once it is received. The agreement to repay from future funds may enable a faster recovery in cases when other sources of assistance are delayed (e.g., due to insurance litigation). HUD requires all grantees to enter into agreements with applicants before the applicant receives CDBG-DR assistance.

Third, the applicant's CDBG-DR award may increase if a reassessment shows that the applicant has additional unmet need.

IV.A.1.(d)(v). Reassess Unmet Need When Necessary. Although long-term recovery is a process, disaster recovery needs are calculated at points in time. As a result, a subsequent change in an applicant's circumstances can affect that applicant's remaining unmet need, meaning the need that was not met by CDBG-DR and other sources of assistance. Oftentimes, unmet need does not become apparent until after CDBG-DR assistance has been provided. Examples may include: a subsequent disaster that causes further damage to a partially rehabilitated home or business; an increase in the cost of construction materials; vandalism; contractor fraud; or theft of materials. Unmet need may also change if other resources become available to pay for costs of the activity (such as FEMA or USACE), and reduce the need for CDBG-DR.

To the extent that an original disaster recovery need was not fully met or was exacerbated by factors beyond the control of the applicant, the grantee may provide additional CDBG-DR funds to meet the increased unmet need.

Grantees must be able to identify and document additional unmet need, for example, by completing a professional inspection to verify the revised estimate of costs to rehabilitate or reconstruct damaged property.

IV.A.1.(e). Special Considerations. The potential for DOB arises most frequently under homeowner rehabilitation programs but is not limited solely to that type of activity. The following examples do not form an exhaustive list of all CDBG-DR funded programs or activities. They are included to illustrate instances when duplicative assistance can occur when assisting other recovery activities:

1. Assistance to businesses. Many grantees carry out economic revitalization programs that provide working capital assistance to businesses. Generally, working capital assistance is calculated after assessing a business's ability to use its current assets to pay its current liabilities. The grantee's DOB analysis must consider total assistance, which includes all sources of financial assistance available to the applicant to pay a portion of liabilities that will become due. For example, a downtown business alliance might award business recovery grants from its funds to cover some of the same liabilities. Even if the downtown business alliance does not call its assistance "working capital" assistance, the amount the business received from the downtown business alliance to pay the same costs as the CDBG-DR funds is a DOB. Therefore, a grantee's basis for calculating CDBG-DR economic development assistance and

the purposes for which the applicant can use the assistance should be clearly identified so that grantees can prevent a DOB. As discussed above, assets such as cash and cash equivalents (excluding deposits of insurance proceeds or other disaster assistance), inventories, short-term investments and securities, accounts receivable, and other assets of the business are not financial assistance, although those assets may be relevant to underwriting.

2. Assistance for infrastructure. State grantees may assist state or local government entities by providing funding to restore infrastructure (public facilities and improvements) after a disaster. CDBG-DR funds used directly by state and local governments for public facilities and improvements, or other purposes are also subject to the DOB requirements of the Stafford Act. For example, a wastewater treatment facility owned by a local government may need to be rehabilitated. In this instance, total assistance, for a DOB analysis, would not only include any other Federal assistance available to rehabilitate the facility, but it must also include any local funds that are available for this activity. And if local funds were previously designated or planned for the activity, but are no longer available, the grantee should document that the local government recipient does not have funds set aside for the activity in any capital improvement plan (or similar document showing planned use of funds).

3. Payments made under the Uniform Relocation Assistance and Real Property Acquisition Policies Act (URA). Grantees may provide a displaced person (as defined under 24 CFR 570.606) with rental assistance payments under the URA or provide temporary relocation assistance (as described in 49 CFR part 24, *Appendix A*, 49 CFR 24.2(a)(9)(ii)(D)) to persons temporarily relocated as a result of a project. Relocation payments made under the URA, as well as under CDBG's optional relocation assistance provisions of 24 CFR 570.606(d), are subject to DOB requirements in this notice and the Consolidated Notice, as well as DOB requirements under the URA that prohibit payments for the same "purpose and effect" as another payment to a displaced person (49 CFR 24.3). To comply with CDBG-DR DOB requirements, before issuance of rental assistance payments required by the URA, grantees must complete a DOB analysis. For example, a CDBG-DR grantee must check FEMA assistance data to determine that FEMA did not provide rental assistance payments during the same time period (under the

URA or as part of a FEMA Individual Assistance Award). Please note that while you cannot duplicate assistance for the same purpose, advisory services and the provision of notices required under the URA are not subject to this analysis because they are not financial assistance to the person, and therefore must be provided in accordance with the URA.

Subsidized Loans. For this notice, subsidized loans (including forgivable loans) are loans other than private loans. Subsidized loans are assistance that must be included in the DOB analysis, unless an exception applies. Section IV.A. of the Consolidated Notice discusses these exceptions and related requirements for the treatment of subsidized loans in a duplication of benefits analysis. The full amount of a subsidized loan available to the applicant for the same purpose as CDBG-DR assistance is assistance that must be included in the DOB calculation unless one of the exceptions in IV.A.1. of the Consolidated Notice applies. A subsidized loan is available when it is accepted, meaning that the borrower has signed a note or other loan document that allows the lender to advance loan proceeds. Both SBA and FEMA provide subsidized loans for disaster recovery. Note that the statutory order of assistance provision pertaining to assistance from FEMA and USACE applies to grants and subsidized loans made by these agencies. Subsidized loans may also be available from other sources.

IV.A.1.(f). Order of Assistance. CDBG-DR appropriations acts generally include a statutory order of assistance for Federal agencies. Although the language may vary among appropriations, the statutory order of assistance typically provides that CDBG-DR funds may not be used for activities reimbursable by or for which funds are made available by FEMA or USACE. This means that grantees must verify whether FEMA or USACE funds are available for an activity (*i.e.* the application period is open) or the costs are reimbursable by FEMA or USACE (*i.e.*, the grantee will receive FEMA or USACE assistance to reimburse the costs of the activity) before awarding CDBG-DR assistance for costs of carrying out the same activity. If FEMA or USACE are accepting applications for the activity, the applicant must seek assistance from those sources before receiving CDBG-DR assistance. If the applicant's costs for the activity will be reimbursed by FEMA or USACE, the grantee cannot provide the CDBG-DR assistance for those costs. In the event that FEMA or USACE assistance is

awarded after CDBG–DR to pay the same costs, it is the CDBG–DR grantee's responsibility to recapture CDBG–DR assistance that duplicates assistance from FEMA or USACE.

Under the Stafford Act, a Federal agency that provides duplicative assistance must collect that assistance. For CDBG–DR grants, the grantee is required to collect duplicative assistance it provides. A grantee that does not collect duplicative CDBG–DR assistance that it provides may resolve this noncompliance by reimbursing its program account with non-Federal funds in the amount of the duplication and reprogramming the use of the funds in accordance with applicable requirements to avoid other corrective or remedial actions.

FEMA regulations at 44 CFR 206.191 set forth a delivery sequence that establishes which source of assistance is duplicative for certain programs. CDBG–DR assistance is not listed in FEMA's sequence, but as a practical matter, CDBG–DR assistance duplicates other sources received before CDBG–DR assistance for the same purpose and portion of need. Any amount received from other sources before the CDBG–DR assistance that is determined to be duplicative must be collected by the grantee. The mandatory agreement to repay (discussed in section IV.A.1.(i) below) can be used to prevent duplication by assistance that is available, but not yet received. If the duplicative assistance is received after CDBG–DR, the grantee must collect the DOB or contact HUD if it has questions about whether another Federal agency is responsible for collecting the duplication.

IV.A.1.(g). Multiple Disasters. When multiple disasters occur in the same location, and the applicant has not recovered from the first disaster at the time of a second disaster, the assistance provided in response to the second disaster may duplicate assistance for the same purpose and need as assistance provided after the first disaster. HUD recognizes that in this scenario, DOB calculations can be complicated. Damage from a second disaster, for example, may destroy work funded and completed in response to the first disaster. The second disaster may also damage or destroy receipts and other documentation of how applicants expended assistance provided after the first disaster.

Therefore, HUD is adopting the following policy that is applicable to circumstances when two disasters occur in the same area, and the applicant has not fully recovered from the first disaster before the second disaster

occurs: Applicants are not required to maintain documentation related to the use of public disaster assistance (Federal, state, and local) beyond the period required by the agency that provided the assistance. If documentation cannot be provided, the grantee may accept a self-certification regarding how the applicant used the other agency's assistance, provided that the applicant is advised of the criminal and civil penalties that apply in cases of false claims and fraud, and the grantee determines that the applicant's total need is consistent with data the grantee has about the nature of damage caused by the disasters (*e.g.*, flood inundation levels). For example, a second disaster strikes three years after an agency provided assistance in response to the first disaster, and that agency required applicants to maintain documentation for two years, the grantee may accept a self-certification regarding how the applicant used the other agency's assistance.

IV.A.1.(h). Recordkeeping. The grantee must document compliance with DOB requirements. Policies and procedures for DOB may be specific for each program funded by the CDBG–DR grantee and should be commensurate with risk. Grantees should be especially careful to sufficiently document the DOB analysis for activities they are carrying out directly. Insufficient documentation on DOB can lead to findings, which can be difficult to resolve if records are missing, inadequate, or inaccurate to demonstrate compliance with DOB requirements.

When documenting its DOB analysis, grantees cannot rely on certification alone for proof of other sources of funds for the same purpose (unless authorized by this notice, see section IV.A.1.(g) above). Any certification by an applicant must be based on supporting evidence that will be kept available for inspection by HUD. For example, if an applicant certifies that other sources of funds were received and expended for a different purpose than the CDBG–DR funds, grantees must substantiate this assertion with an additional source of information (*e.g.*, physical inspections, credit card statements, work estimates, contractor invoices, flood inundation records, or receipts). For these reasons, HUD recommends that as soon as possible after a disaster, grantees advise the public and potential applicants to retain all receipts that document expenditures for recovery needs. Grantees should consult their CPD specialist or CPD Representative with questions about the sufficiency of documentation.

IV.A.1.(i). Agreement to Repay. The Stafford Act requires grantees to ensure that applicants agree to repay all duplicative assistance to the agency providing that Federal assistance. To address any potential DOB, each applicant must also enter into an agreement with the CDBG–DR grantee to repay any assistance later received for the same purpose for which the CDBG–DR funds were provided. This agreement can be in the form of a subrogation agreement or similar document and must be signed by every applicant before the grantee disburses any CDBG–DR assistance to the applicant.

In its policies and procedures, the grantee must establish a method to monitor each applicant's compliance with the agreement for a reasonable period after project completion (*i.e.*, a time period commensurate with risk). Additionally, section III.A.1. of the Consolidated Notice requires a grantee's agreement to also include the following language: "Warning: Any person who knowingly makes a false claim or statement to HUD may be subject to civil or criminal penalties under 18 U.S.C. 287, 1001 and 31 U.S.C. 3729."

IV.A.1.(j). Collecting a Duplication. If a potential DOB is discovered after CDBG–DR assistance has been provided, the grantee must reassess the applicant's need at that time (see section IV.A.1.(d)(v) above). If additional need is not demonstrated, CDBG–DR funds shall be recaptured to the extent they are in excess of the remaining need and duplicate other assistance received by the applicant for the same purpose. However, this determination may depend on what sources of assistance were last received by the applicant.

If a grantee fails to recapture funds from an applicant, HUD may impose corrective actions pursuant to 24 CFR 570.495, 24 CFR 570.910, and **Federal Register** notices, as applicable. Also, HUD reminds grantees that the Stafford Act states that "A person receiving Federal assistance for a major disaster or emergency shall be liable to the United States to the extent that such assistance duplicates benefits available to the person for the same purpose from another source." A grantee's failure to collect duplication of benefits does not remove an applicant's potential liability to the United States. A grantee that does not collect duplicative CDBG–DR assistance that it provides, should review HUD's guidance in the second paragraph of section IV.A.1.(f) above.

The grantee may refer to any relevant guidance or the debt collection procedures in place for the state or local government. HUD is available to

provide guidance to grantees in establishing or revising the grantee's duplication of benefits policies and procedures.

CDBG–DR grantees awarded funds for disasters occurring in 2022 can find the additional DOB requirements in Section IV.A. of the Consolidated Notice.

IV.A.2. CDBG–DR mitigation set-aside. The Appropriations Acts require HUD to include in any allocation of CDBG–DR funds for unmet needs an additional amount of 15 percent for mitigation activities (“CDBG–DR mitigation set-aside”). Grantees should consult Table 1 for the amount allocated specifically for the CDBG–DR mitigation set-aside. For purposes of grants under this notice, mitigation activities are defined as those activities that increase resilience to disasters and reduce or eliminate the long-term risk of loss of life, injury, damage to and loss of property, and suffering and hardship, by lessening the impact of future disasters.

In the grantee's action plan, it must identify how the proposed use of the CDBG–DR mitigation set-aside will: (1) meet the definition of mitigation activities; (2) address the current and future risks as identified in the grantee's mitigation needs assessment in the MID areas; (3) be CDBG-eligible activities under title I of the HCDA or otherwise eligible pursuant to a waiver or alternative requirement; and (4) meet a national objective.

Unlike recovery activities where grantees must demonstrate that their activities “tie-back” to the specific disaster and address a specific unmet recovery need for which the CDBG–DR funds were appropriated, activities funded by the CDBG–DR mitigation set-aside do not require such a “tie-back” to the specific qualified disaster that has served as the basis for the grantee's allocation. Instead, grantees must demonstrate that activities funded by the CDBG–DR mitigation set-aside meet the provisions included as (1) through (4) in the prior paragraph, to be eligible. Grantees must report activities as a “MIT” activity type in DRGR so that HUD and the public can determine that the grantee has fulfilled the requirement for the CDBG–DR mitigation set-aside.

Grantees may also meet the requirement of the CDBG–DR mitigation set-aside by including eligible recovery activities that both address the impacts of the disaster (*i.e.*, have “tie-back” to the specific qualified disaster) and incorporate mitigation measures into the recovery activities. In section II.A.2.b of the Consolidated Notice, grantees are instructed to incorporate mitigation measures when carrying out activities to construct, reconstruct, or rehabilitate

residential or non-residential structures with CDBG–DR funds as part of activities eligible under 42 U.S.C. 5305(a) (including activities authorized by waiver and alternative requirement). Additionally, in section II.A.2.c of the Consolidated Notice, grantees are required to establish resilience performance metrics for those activities.

If grantees wish to count those activities towards the grantee's CDBG–DR mitigation set-aside, grantees must: (1) Document how those activities and the incorporated mitigation measures will meet the definition of mitigation, as provided above; and (2) Report those activities as a “MIT” activity type in DRGR so they are easily tracked.

IV.A.2.a. Mitigation needs assessment. In addition to the requirements prescribed in section III.C.1.a of the Consolidated Notice that grantees must develop an impact and unmet needs assessment, grantees receiving an award under this Allocation Announcement Notice must also include in their action plan a mitigation needs assessment to inform the activities funded by the CDBG–DR mitigation set-aside. Each grantee must assess the characteristics and impacts of current and future hazards identified through its recovery from the qualified disaster and any other Presidentially declared disaster. Mitigation solutions designed to be resilient only for threats and hazards related to a prior disaster can leave a community vulnerable to negative effects from future extreme events related to other threats or hazards. When risks are identified among other vulnerabilities during the framing and design of mitigation projects, implementation of those projects can enhance protection and save lives, maximize the utility of scarce resources, and benefit the community long after the projects are complete.

Accordingly, each grantee receiving a CDBG–DR allocation under this notice must conduct a risk-based assessment to inform the use of its CDBG–DR mitigation set-aside considering identified current and future hazards. Grantees must assess their mitigation needs in a manner that effectively addresses risks to indispensable services that enable continuous operation of critical business and government functions and are critical to human health and safety or economic security. In the mitigation needs assessment, each grantee must cite data sources and must, at a minimum, use the risks identified in the current FEMA-approved state or local Hazard Mitigation Plan (HMP). If a jurisdiction is currently updating an expired HMP, the grantee's agency administering the CDBG–DR funds must

consult with the agency administering the HMP update to identify the risks that will be included in the assessment. Mitigation needs evolve over time and grantees are to amend the mitigation needs assessment and action plan as conditions change, additional mitigation needs are identified, and additional resources become available.

IV.A.2.b. Connection of programs and projects to the mitigation needs assessment. Grantees are required by section III.C.1.b of the Consolidated Notice to describe the connection between identified unmet needs and the allocation of CDBG–DR resources. In a similar fashion, the plan must provide a clear connection between a grantee's mitigation needs assessment and its proposed activities in the MID areas funded by the CDBG–DR mitigation set-aside (or outside in connection to the MID areas as described in section II.A.3 of the Consolidated Notice). To maximize the impact of all available funds, grantees are encouraged to coordinate and align these funds with other projects funded with CDBG–DR and CDBG–MIT funds, as well as other disaster recovery activities funded by FEMA, USACE, the U.S. Forest Service, and other agencies as appropriate. Grantees are encouraged to fund planning activities that complement FEMA's Building Resilient Infrastructure and Communities (BRIC) program and to upgrade mapping, data, and other capabilities to better understand evolving disaster risks.

IV.A.3. Interchangeability of disaster funds. The Appropriations Acts gives the Secretary authority to authorize grantees that receive an award in this Allocation Announcement Notice and under prior or future appropriations to use those funds interchangeably and without limitation for the same activities related to unmet recovery needs in the MID areas resulting from a major disaster in the Appropriations Acts or in prior or future appropriation acts, when the MID areas overlap and when the use of the funds will address unmet recovery needs of major disasters in the Appropriations Acts or in any prior or future appropriation acts.

Based on this authority, the Secretary authorizes grantees receiving a CDBG–DR grant under the Appropriations Acts and prior or future appropriation acts for activities authorized under title I of the HCDA for a specific qualifying disaster(s) to use these funds interchangeably and without limitation for the same activities in MID areas resulting from a major disaster in prior or future appropriation acts, as long as the MID areas overlap and the activities address unmet needs of both disasters.

Grantees are reminded that expanding the eligible beneficiaries of activities in an action plan funded by any prior or future acts to include those impacted by the specific qualifying disaster(s) in this notice requires the submission of a substantial action plan amendment in accordance with section III.C.6 of the Consolidated Notice. Additionally, all waivers and alternative requirements associated with a CDBG–DR grant apply to the use of the funds provided by that grant, regardless of which disaster the funded activity will address.

For example, if a grantee is receiving funds under this notice for a disaster occurring in 2022 and the MID areas for the 2022 disaster overlap with the MID areas for a disaster that occurred in 2017, the grantee may choose to use the funds allocated under this notice to address unmet needs of both the 2017 disaster and the 2022 disaster. In doing so, the grantee must follow the rules and requirements outlined in this notice. However, if the grantee chooses to use its CDBG–DR grant awarded due to a disaster that occurred in 2017 to address unmet needs of both that disaster and the 2022 disaster, the grantee must follow the rules and requirements outlined in the **Federal Register** notices applicable to its CDBG–DR grant for 2017 disasters.

IV.A.4. Assistance to utilities. The Appropriations Acts provide that funds “may be used by a grantee to assist utilities as part of a disaster-related eligible activity under section 105(a) of the Housing and Community Development Act of 1974 (42 U.S.C. 5305(a)).”

Accordingly, paragraph III.G.3 of the Consolidated Notice does not apply to funds under the Appropriations Acts, and HUD is adding a modified alternative requirement that applies in lieu of paragraph III.G.3.

While it is possible that not every CDBG–DR assisted utility will serve predominantly low- and moderate-income (LMI) populations, HUD recognizes that LMI populations would benefit especially from the increased resilience and recovery of private utilities. HUD also recognizes that privately-owned, for-profit utilities have a means of obtaining private investment or otherwise recapturing costs from ratepayers. Therefore, HUD’s alternative requirement below includes basic safeguards that HUD has determined are necessary to ensure that costs comply with the certification to give maximum feasible priority to activities that benefit LMI persons and that costs are necessary and reasonable and do not duplicate other financial assistance. The modified alternative requirement also

makes clear that assistance to utilities is subject to all other requirements that apply to the use of funds, consistent with the requirement in the Appropriations Acts that funds must be for an “eligible activity under section 105(a).” If a grantee needs to submit a substantial amendment to add any activity based on these new alternative requirements, they must follow section III.C.6.a in the Consolidated Notice.

For grants made in response to 2022 disasters under the Appropriations Acts, the following alternative requirement applies:

A grantee may assist private for-profit, non-profit, or publicly owned utilities as part of disaster-related activities that are eligible under section 105(a) of the HCDA, or otherwise made eligible through a waiver or alternative requirement, provided that the grantee complies with the following:

1. The funded activity must comply with applicable CDBG–DR requirements, including the requirements that the assisted activity will meet a national objective, the activity will address an unmet recovery need or a risk identified in the grantee’s mitigation needs assessment, and if the assistance is provided to a for-profit entity for an economic development project under section 105(a)(17), the grantee must first comply with the underwriting requirements in section II.D.6 of the Consolidated Notice.

2. Each grantee must carry out the grant consistent with the grantee’s certification that “With respect to activities expected to be assisted with CDBG–DR funds, the action plan has been developed so as to give the maximum feasible priority to activities that will benefit low- and moderate-income families.”

To fortify compliance with the existing certification, if the grantee carries out activities that assist privately-owned, for-profit utilities, the grantee must prioritize assistance to for-profit utilities that will benefit areas where at least 51 percent of the residents are LMI persons and demonstrate how assisting the private, for-profit utility will benefit those areas.

3. The grantee must determine that the costs of the activity to assist a utility are necessary and reasonable and that they do not duplicate other financial assistance. To fortify these requirements and achieve a targeted use of funds and to safeguard against the potential over-subsidization when assistance is used to carry out activities that benefit private, for-profit utilities, the grantee must document that the level of assistance provided to a private, for-profit utility addresses only the actual identified

needs of the utility. Additionally, the grantee must establish policies and procedures to ensure that the CDBG–DR funds that assist private, for-profit utilities reflect the actual identified financing needs of the assisted businesses by establishing a mix of financing terms (loan, forgivable loan, and/or grant) for each assisted private, for-profit utility, based on the business’s financial capacity, in order to ensure that assistance is based on actual identified need.

IV.B. Clarifications to the Consolidated Notice

IV.B.1. Reimbursement Requirements for Grants Under the Appropriations Acts. This section sets out requirements for 2022 disasters under the Appropriations Acts. In paragraph III.F.5 of the Consolidated Notice, HUD permits grantees to charge to grants the pre-award and pre-application costs of homeowners, renters, businesses, and other qualifying entities for eligible costs these applicants have incurred in response to an eligible disaster covered under a grantee’s applicable Allocation Announcement Notice. In addition to other requirements, paragraph III.F.5 stipulates that grantees may charge the eligible pre-application costs to the grant only if (1) the person or private entity incurred the expenses within one year after the applicability date of the grantee’s Allocation Announcement Notice (or within one year after the date of the disaster, whichever is later); and (2) the person or entity pays for the cost before the date on which the person or entity applies for CDBG–DR assistance.

Congress may enact multiple supplemental appropriations of CDBG–DR funds for disasters occurring in the same year and HUD may then publish multiple notices announcing CDBG–DR grants for the same disaster. For example, HUD announced CDBG–DR grants for disasters occurring in 2022 in this notice. If Congress appropriates additional funds for 2022 disasters in a future appropriations act, grantees may find it difficult to track expenses incurred within one year after the applicability date of this notice and another Allocation Announcement Notice, given that funds for disasters occurring in 2022 would be announced in different notices. To avoid confusion and to apply a uniform time frame to reimbursement of all pre-application costs for 2022 disasters, the requirement in III.F.5.(1) in the Consolidated Notice that states, “The person or private entity incurred the expenses within one year after the applicability date of the grantee’s Allocation Announcement Notice (or within one year after the date

of the disaster, whichever is later)” shall not apply, and instead, grantees shall comply with the following alternative to that requirement in III.F.5.(1): “The person or private entity incurred the expenses within one year after the applicability date of the notice that announced the *initial* allocation of CDBG–DR funds (or within one year after the date of the disaster, whichever is later).” For grantees receiving an allocation for a 2022 disaster, the notice that announced the initial allocation of CDBG–DR funds is this notice.

IV.B.2. Clarification of the green and resilient building standard. Paragraph II.B.2.a. of the Consolidated Notice requires that all covered construction (new construction, reconstruction, and rehabilitation) that is assisted with CDBG–DR funds meet an industry-recognized standard that has achieved certain certifications described in the notice. HUD updated its building standards to support the adoption and enforcement of modern and resilient codes for grants subject to the **Federal Register** notices published on February 3, 2022, at 87 FR 6364; May 24, 2022 at 87 FR 31636; January 18, 2023, at 88 FR 3198; and this notice (including requirements identified as the “Consolidated Notice” incorporated by each of these notices as an Appendix B). During this update, HUD inadvertently omitted a standard.

Accordingly, HUD clarifies that paragraph II.B.2.a. in the “Consolidated Notice” (as defined in the previous sentence) allows a grantee to use either the ICC–700 National Green Building Standard (NGBS) Green or NGBS Green+ Resilience standard, among other industry-recognized standards. For grants made in response to disasters occurring in 2020, 2021, and 2022, this notice replaces paragraph II.B.2.a. in the Appendix B Consolidated Notice attached to this notice and to the document titled “Consolidated Notice” in Appendix B to each of the **Federal Register** notices published on February 3, 2022, at 87 FR 6364; May 24, 2022 at 87 FR 31636; January 18, 2023, at 88 FR 3198; and this notice. In lieu of the text originally published in paragraph II.B.2.a. of those appendices (which is hereby replaced), the following alternative requirement applies:

II.B.2.a. Green and resilient building standard for new construction and reconstruction of housing. Grantees must meet the Green and Resilient Building Standard, as defined in this subparagraph, for: (i) all new construction and reconstruction (*i.e.*, demolishing a housing unit and rebuilding it on the same lot in substantially the same manner) of

residential buildings and (ii) all rehabilitation activities of substantially damaged residential buildings, including changes to structural elements such as flooring systems, columns, or load-bearing interior or exterior walls.

The Green and Resilient Building Standard requires that all construction covered by the paragraph above and assisted with CDBG–DR funds meet an industry-recognized standard that has achieved certification under (i) Enterprise Green Communities; (ii) LEED (New Construction, Homes, Midrise, Existing Buildings Operations and Maintenance, or Neighborhood Development); (iii) ICC–700 National Green Building Standard (NGBS) Green or NGBS Green+ Resilience; (iv) Living Building Challenge; or (v) any other equivalent comprehensive green building program acceptable to HUD.

IV.B.3. Clarification of the Use of “Uncapped” Income Limits. The Quality Housing and Work Responsibility Act of 1998 (Title V of Pub. L. 105–276) enacted a provision that directs the Department to grant exceptions to at least 10 jurisdictions that are currently “capped” under HUD’s low and moderate-income limits. Under this exception, several CDBG entitlement grantees may use “uncapped” income limits that reflect 80 percent of the actual median income for the area. Each year, HUD publishes guidance on its website identifying which grantees may use uncapped limits.

Accordingly, HUD clarifies that, the annual uncapped income limits published by HUD applies to CDBG–DR funded activities in jurisdictions covered by the uncapped limits, including jurisdictions that receive disaster recovery funds from a state CDBG–DR grantee. This alternative requirement applies to grants made in response to disasters occurring in 2020, 2021, and 2022 that are subject to **Federal Register** notices published on February 3, 2022, at 87 FR 6364; May 24, 2022 at 87 FR 31636; January 18, 2023, at 88 FR 3198; and this notice (including requirements identified as a “Consolidated Notice” incorporated by each of these notices as an Appendix B).

V. Duration of Funding

The Appropriations Acts make the funds available for obligation by HUD until expended. HUD waives the provisions at 24 CFR 570.494 and 24 CFR 570.902 regarding timely distribution and expenditure of funds and establishes an alternative requirement providing that each grantee must expend 100 percent of its allocation within six years of the date

HUD signs the grant agreement. HUD may extend the time period in this alternative requirement and associated grant period of performance administratively, if good cause for such an extension exists at that time, as requested by the grantee, and approved by HUD. When the period of performance has ended, HUD will close out the grant and any remaining funds not expended by the grantee on appropriate programmatic purposes will be recaptured by HUD.

VI. Assistance Listing Numbers (Formerly Known as the CFDA Number)

The Assistance Listing Numbers (formerly known as the Catalog of Federal Domestic Assistance numbers) for the disaster recovery grants under this notice are as follows: 14.218; 14.228.

VII. Finding of No Significant Impact

A Finding of No Significant Impact (FONSI) with respect to the environment has been made in accordance with HUD regulations at 24 CFR part 50, which implement section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)). The FONSI is available online on HUD’s CDBG–DR website at https://www.hud.gov/program_offices/comm_planning/cdbg-dr. Due to security measures at the HUD Headquarters building, an advance appointment to review the docket file must be scheduled by calling the Regulations Division at 202–708–3055 (this is not a toll-free number). HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech or communication disabilities. To learn more about how to make an accessible telephone call, please visit <https://www.fcc.gov/consumers/guides/telecommunications-relay-service-trs>.

Adrianne Todman,
Deputy Secretary.

Appendix A

Allocation of CDBG–DR Funds to Most Impacted and Distressed Areas Due to Presidentially Declared Disasters Occurring in 2022

Background

The Continuing Appropriation Act, 2023 (Pub. L. 117–180, Division A) (approved September 30, 2022) appropriated \$2 billion in CDBG–Disaster Recovery (CDBG–DR) funds for “major disasters that occurred in 2021 or 2022” and the Department of Housing and Urban Development Appropriations Act, 2023 (Pub. L. 117–328, Division L, Title II) (approved on December

29, 2022) appropriated \$3 billion of CDBG—DR for disasters “that occurred in 2022 or later until such funds are fully allocated”. Both laws instruct HUD that the funds are “for the same purposes and under the same terms and conditions as funds appropriated under such heading in title VIII of the Disaster Relief Supplemental Appropriations Act, 2022 (division B of Pub. L. 117–43)”.

The statutory text related to the allocation in Public Law 117–43 is as follows:

“ . . . for necessary expenses for activities authorized under title I of the Housing and Community Development Act of 1974 (42 U.S.C. 5301 *et seq.*) related to disaster relief, long-term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation, in the most impacted and distressed areas resulting from a major disaster. . . . *Provided*, That amounts made available under this heading in this Act shall be awarded directly to the State, unit of general local government, or Indian tribe (as such term is defined in section 102 of the Housing and Community Development Act of 1974 (42 U.S.C. 5302)) at the discretion of the Secretary: *Provided further*, That the Secretary shall allocate, using the best available data, an amount equal to the total estimate for unmet needs for qualifying disasters under this heading in this Act: *Provided further*, That any final allocation for the total estimate for unmet need made available under the preceding proviso shall include an additional amount of 15 percent of such estimate for additional mitigation: ”

This methodology applies to allocations for disasters occurring on or after January 1, 2022 and had been declared major disasters as of October 30, 2022. It reflects the \$553,371,000 remaining from the \$2 billion appropriated under Public Law 117–180 (\$1.44 billion had been provided for 2021 disasters in an earlier allocation) and \$2,837,849,000 under Public Law 117–328.

Most Impacted and Distressed Areas

As with prior CDBG—DR appropriations, HUD is not obligated to allocate funds for all major disasters occurring in the statutory timeframes. HUD is directed to use the funds “in the most impacted and distressed areas.” HUD has implemented this directive by limiting CDBG—DR formula allocations to grantees with major disasters that meet these standards:

(1) Individual and Households Program (IHP) designation. HUD has limited allocations to those disasters where the Federal Emergency Management Agency (FEMA) had determined the damage was sufficient to declare the disaster as eligible to receive IHP funding.

(2) Concentrated damage. HUD has limited its estimate of serious unmet housing need to counties and/or counties with zip codes with high levels of damage, collectively referred to as “most impacted areas.” For this allocation, HUD is defining most impacted areas as either most impacted counties—counties exceeding \$10 million in serious unmet housing needs—and most impacted Zip Codes—Zip Codes with \$2 million or more of serious unmet housing needs. The calculation of serious unmet housing needs is described below.

For disasters that meet the most impacted threshold described above, the unmet need allocations are based on the following factors summed together:

- (1) Repair estimates for seriously damaged owner-occupied units without insurance (with some exceptions) in most impacted areas after FEMA and Small Business Administration (SBA) repair grants or loans;
- (2) Repair estimates for seriously damaged rental units occupied by very low-income renters in most impacted areas;
- (3) Repair and content loss estimates for small businesses with serious damage denied by SBA; and
- (4) The estimated local cost share for Public Assistance Category C to G projects.

Methods for Estimating Serious Unmet Needs for Housing

The data HUD uses to calculate unmet needs for 2022 qualifying disasters come from the FEMA IHP data on housing-unit damage as of January 10, 2023, and reflect disasters occurring in 2022 and declared on or before October 30, 2022.

The core data on housing damage for both the unmet housing needs calculation and the concentrated damage are based on home inspection data for FEMA’s IHP and SBA’s disaster loan program. HUD calculates “unmet housing needs” as the number of housing units with unmet needs times the estimated cost to repair those units less repair funds estimated to be provided by FEMA and SBA.

Each of the FEMA IHP inspected owner units are categorized by HUD into one of five categories:

- *Minor-Low*: Less than \$3,000 of FEMA inspected real property damage.
- *Minor-High*: \$3,000 to \$7,999 of FEMA inspected real property damage.
- *Major-Low*: \$8,000 to \$14,999 of FEMA inspected real property damage and/or 1 to 3.9 feet of flooding on the first floor.
- *Major-High*: \$15,000 to \$28,800 of FEMA inspected real property damage and/or 4 to 5.9 feet of flooding on the first floor.
- *Severe*: Greater than \$28,800 of FEMA inspected real property damage or determined destroyed and/or six or more feet of flooding on the first floor.

When owner-occupied properties also have a personal property inspection or only have a personal property inspection, HUD reviews the personal property damage amounts such that if the personal property damage places the home into a higher need category over the real property assessment, the personal property amount is used. The personal property-based need categories for owner-occupied units are defined as follows:

- *Minor-Low*: Less than \$2,500 of FEMA inspected personal property damage.
- *Minor-High*: \$2,500 to \$3,499 of FEMA inspected personal property damage.
- *Major-Low*: \$3,500 to \$4,999 of FEMA inspected personal property damage or 1 to 3.9 feet of flooding on the first floor.
- *Major-High*: \$5,000 to \$9,000 of FEMA inspected personal property damage or 4 to 5.9 feet of flooding on the first floor.
- *Severe*: Greater than \$9,000 of FEMA inspected personal property damage or determined destroyed and/or 6 or more feet of flooding on the first floor.

To meet the statutory requirement of “most impacted” in this legislative language, homes are determined to have a high level of damage if they have damage of “major-low” or higher. That is, they have a FEMA inspected real property damage of \$8,000 or above, personal property damage \$3,500 or above, or flooding 1 foot or above on the first floor.

Furthermore, a homeowner with flooding outside the one percent risk flood hazard area is determined to have unmet needs if they reported damage and no flood insurance to cover that damage. For homeowners inside the one percent risk flood hazard area, homeowners without flood insurance with flood damage below the greater of national median or 120 percent of Area Median Income are determined to have unmet needs. For non-flood damage, homeowners without hazard insurance with incomes below the greater of national median or 120 percent of Area Median Income are included as having unmet needs. The unmet need categories for these types of homeowners are defined as above for real and personal property damage.

FEMA IHP does not inspect rental units for real property damage so personal property damage is used as a proxy for unit damage. Each of the FEMA-inspected rental units are categorized by HUD into one of five categories:

- *Minor-Low*: Less than \$1,000 of FEMA inspected personal property damage.
- *Minor-High*: \$1,000 to \$1,999 of FEMA inspected personal property damage or determination of “Moderate” damage by the FEMA inspector.
- *Major-Low*: \$2,000 to \$3,499 of FEMA inspected personal property damage or 1 to 3.9 feet of flooding on the first floor or determination of “Major” damage by the FEMA inspector.
- *Major-High*: \$3,500 to \$7,500 of FEMA inspected personal property damage or 4 to 5.9 feet of flooding on the first floor.
- *Severe*: Greater than \$7,500 of FEMA inspected personal property damage or determined destroyed and/or 6 or more feet of flooding on the first floor or determination of “Destroyed” by the FEMA inspector.

To meet the statutory requirement of “most impacted” for rental properties, homes are determined to have a high level of damage if they have damage of “major-low” or higher. That is, they have a FEMA personal property damage assessment of \$2,000 or greater or flooding 1 foot or above on the first floor.

Furthermore, landlords are presumed to have adequate insurance coverage unless the unit is occupied by a renter with income less than the greater of the Federal poverty level or 50 percent of the area median income. Units occupied by a tenant with income less than the greater of the poverty level or 50 percent of the area median income are used to calculate likely unmet needs for affordable rental housing.

The average cost to fully repair a home for a specific disaster to code within each of the damage categories noted above is calculated using the median real property damage repair costs determined by the SBA for its disaster loan program based on a match comparing FEMA and SBA inspections by each of the FEMA damage categories described above.

If there is a match of 20 or more SBA inspections to FEMA inspections for any damage category, the median damage estimate for the SBA properties is used less the estimated average FEMA IHP repair grant and average SBA disaster loan grant weighted on take-up rates, which are generally high for

IHP and low and for SBA. Except that no matched multiplier can be less than the 25th percentile for all IHP eligible disasters combined in eligible disaster years at the time of the allocation calculation or more than the 75th percentile for all IHP eligible

disasters combined with data available as of the allocation.

If there is a match of fewer than 20 SBA inspections to FEMA inspections within individual damage categories, these multipliers are used which are based on the 2020 and 2021 disaster years:

Disaster type	Multipliers by disaster type		
	Major-low	Major-high	Severe
Dam/Levee Break	\$33,007	\$47,078	\$47,078
Earthquake	27,141	33,714	134,503
Fire	22,971	82,582	134,503
Flood	47,074	57,856	64,513
Hurricane	36,800	45,952	45,952
Severe Ice Storm	33,528	33,714	36,592
Severe Storm(s)	22,971	37,299	37,299
Tornado	52,961	82,582	134,503

A separate multiplier is applied to mobile homes for all disaster types. Where there are fewer than 20 mobile homes for a match for a disaster, the mobile home multipliers are \$49,571 for major-low, \$60,189 for major-high, and \$67,594 for severe. If there are 20 or more matches for a specific disaster's mobile homes, that specific disaster multiplier is used.

Methods for Estimating Serious Unmet Economic Revitalization Needs

Based on SBA disaster loans to businesses using data for 2022 disasters from as of January 4, 2023, HUD calculates the median real estate and content loss by the following damage categories for each disaster:

- *Category 1*: real estate + content loss = below \$12,000
- *Category 2*: real estate + content loss = \$12,000–\$29,999
- *Category 3*: real estate + content loss = \$30,000–\$64,999
- *Category 4*: real estate + content loss = \$65,000–\$149,999
- *Category 5*: real estate + content loss = \$150,000 and above

For properties with real estate and content loss of \$30,000 or more, HUD calculates the estimated amount of unmet needs for small businesses by multiplying the median damage estimates for the categories above by the number of small businesses denied an SBA loan, including those denied a loan prior to inspection due to inadequate credit or income (or a decision had not been made), under the assumption that damage among those denied at pre-inspection have the same distribution of damage as those denied after inspection.

Methods for Estimating Unmet Infrastructure Needs

To calculate 2022 unmet needs for infrastructure projects, HUD received FEMA cost estimates on January 10, 2023, of the expected local cost share to repair the permanent public infrastructure (Categories C to G) to their pre-storm condition.

Allocation Calculation

Once eligible entities are identified using the above criteria, the allocation to individual grantees represents their

proportional share of the estimated unmet needs. For the formula allocation, HUD calculates total unmet recovery needs for eligible disasters as the aggregate of:

- Serious unmet housing needs in most impacted and distressed areas;
- Serious unmet business needs; and
- Unmet infrastructure need.

Mitigation is calculated as 15 percent of the unmet need calculation, and then rounded to the nearest \$1,000.

Sub-Disaster Allocations for Local Governments

Sub-allocations to local governments are made from this disaster level allocation. Each disaster that has allocations to local governments has a slightly different methodology reflecting best available data for that disaster at the local level and program administration considerations.

- DR4665–MO. This disaster is concentrated in two entitlement areas. Local data from this July 2022 disaster allows for consideration of housing, business, and infrastructure data for all impacted counties. St. Louis County has the greatest serious housing damage for a most impacted and distressed area designation while St. Louis City has the greatest concentration of public assistance category C to G match requirements in excess of \$10 million for a Most Impacted and Distressed area designation.

- DR4657 & DR4670–OK. These two Oklahoma major disaster declarations were for the same event, DR 4657 received an IHP designation for several counties in Oklahoma and DR 4670 a Public Assistance designation for Muscogee (Creek). This disaster was made eligible based on a concentration of damage in a zip code. To ease program administration the Most Impacted and Distressed Areas are defined as both Okmulgee County and Muscogee (Creek) Oklahoma Tribal Statistical Area (OTSA). These areas overlap and HUD has identified both as most impacted and distressed areas for purposes of this allocation.

- DR 4673–FL. Hurricane Ian has led to the designation of 18 Most Impacted Counties and 1 Most Impacted Zip Code. Within those areas are dozens of affected regular CDBG entitlement areas. There are four counties,

however, that are entitlement counties under the regular CDBG Urban County program and, when their need is combined with the 6 city entitlement cities within them, each have more than \$100 million in serious unmet housing needs, which is a natural break in the distribution from the other CDBG program entitlement communities. With administrative costs capped at 5 percent, larger grants offer more program efficiencies, HUD is allocating directly to the most seriously impacted counties to serve their entire county (including all cities within them) and the state to serve the areas for the other counties where funds are not directly allocated.

Appendix B—The Consolidated Notice CDBG–DR Consolidated Notice Waivers and Alternative Requirements

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I. Waivers and Alternative Requirements

CDBG–DR grantees that are subject to this Consolidated Notice, as indicated in each **Federal Register** notice that announces allocations of the appropriated CDBG–DR funds (“Allocation Announcement Notice”), must comply with all waivers and alternative requirements in the Consolidated Notice, unless expressly made inapplicable (e.g., a waiver that applies to states only does not apply to units of general local governments and Indian tribes). Except as described in applicable waivers and alternative requirements, the statutory and regulatory provisions governing the CDBG program (and for Indian tribes, the Indian CDBG program) shall apply to grantees receiving a CDBG–DR allocation. Statutory provisions (title I of the HCDA) that apply to all grantees can be found at 42 U.S.C. 5301 *et seq.* and regulatory requirements, which differ for each type of grantee, are described in each of the three paragraphs below.

Except as modified, the State CDBG program rules shall apply to state grantees receiving a CDBG–DR allocation. Applicable State CDBG program regulations are found at 24 CFR part 570, subpart I. For insular areas, HUD waives the provisions of 24 CFR part 570, subpart F and imposes the following alternative requirement: Insular areas shall administer their CDBG–DR allocations in accordance with the regulatory and statutory provisions governing the State CDBG program, as modified by the Consolidated Notice.

Except as modified, statutory and regulatory provisions governing the Entitlement CDBG Program shall apply to unit of general local government grantees (often referred to as local government grantees in appropriations acts). Applicable Entitlement CDBG Program regulations are found at 24 CFR part 570, as described in 570.1(a).

Except as modified, CDBG–DR grants made by HUD to Indian tribes shall be subject to the statutory provisions in title I of the HCDA that apply to Indian tribes and the regulations in 24 CFR part 1003 governing the Indian CDBG program, except those requirements in part 1003 related to the funding application and selection process.

References to the action plan in the above regulations shall refer to the action plan required by the Consolidated Notice and not to the consolidated plan action plan required by 24 CFR part 91. All references pertaining to timelines and/or deadlines are in terms of calendar days unless otherwise noted.

II. Eligible Activities

II.A. Clarification of Disaster-Related Activities

CDBG–DR funds are provided for necessary expenses for activities authorized under title I of the HCDA related to disaster relief, long-term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation of risk associated with activities carried out for these purposes, in the “most impacted and distressed” areas (identified by

HUD or the grantee) resulting from a major disaster. All CDBG–DR funded activities must address an impact of the disaster for which funding was allocated. Accordingly, each activity must: (1) address a direct or indirect impact from the disaster in a most impacted and distressed area; (2) be a CDBG-eligible activity (or be eligible under a waiver or alternative requirement); and (3) meet a national objective. When appropriations acts provide an additional allocation amount for mitigation of hazard risks that does not require a connection to the qualifying major disaster, requirements for the use of those funds will be included in the Allocation Announcement Notice.

II.A.1. Documenting a Connection to the Disaster. Grantees must maintain records that document how each funded activity addresses a direct or indirect impact from the disaster. Grantees may do this by linking activities to a disaster recovery need that is described in the impact and unmet needs assessment in the action plan (requirements for the assessment are addressed in section III.C.1.a.). Sufficient documentation of physical loss must include damage or rebuilding estimates, insurance loss reports, images, or similar information that documents damage caused by the disaster. Sufficient documentation for non-physical disaster-related impacts must clearly show how the activity addresses the disaster impact, e.g., for economic development activities, data about job loss or businesses closing after the disaster or data showing how pre-disaster economic stressors were aggravated by the disaster; or for housing activities, a post-disaster housing analysis that describes the activities that are necessary to address the post-disaster housing needs.

II.A.2. Resilience and hazard mitigation. The Consolidated Notice will help to improve long-term community resilience by requiring grantees to fully incorporate mitigation measures that will protect the public, including members of protected classes, vulnerable populations, and underserved communities, from the risks identified by the grantee among other vulnerabilities. This approach will better ensure the revitalization of the community long after the recovery projects are complete.

Accordingly, HUD is adopting the following alternative requirement to section 105(a): Grantees may carry out the activities described in section 105(a), as modified by waivers and alternative requirements, to the extent that the activities comply with the following:

II.A.2.a. Alignment with mitigation plans. Grantees must ensure that the mitigation measures identified in their action plan will align with existing hazard mitigation plans submitted to the Federal Emergency Management Agency (FEMA) under section 322 of the Robert T. Stafford Disaster Relief and Emergency Assistance Act (42 U.S.C. 5165) or other state, local, or tribal hazard mitigation plans.

II.A.2.b. Mitigation measures. Grantees must incorporate mitigation measures when carrying out activities to construct, reconstruct, or rehabilitate residential or non-residential structures with CDBG–DR funds as part of activities eligible under 42 U.S.C.

5305(a) (including activities authorized by waiver and alternative requirement). To meet this alternative requirement, grantees must demonstrate that they have incorporated mitigation measures into CDBG–DR activities as a construction standard to create communities that are more resilient to the impacts of recurring natural disasters and the impacts of climate change. When determining which mitigation measures to incorporate, grantees should design and construct structures to withstand existing and future climate impacts expected to occur over the service life of the project.

II.A.2.c. Resilience performance metrics. Before carrying out CDBG–DR funded activities to construct, reconstruct, or rehabilitate residential or non-residential structures, the grantee must establish resilience performance metrics for the activity, including: (1) an estimate of the projected risk to the completed activity from natural hazards, including those hazards that are influenced by climate change (e.g., high winds destroying newly built homes), (2) identification of the mitigation measures that will address the projected risks (e.g., using building materials that are able to withstand high winds), and (3) an assessment of the benefit of the grantee's measures through verifiable data (e.g., 10 newly built homes will withstand high winds up to 100 mph).

II.A.3. Most impacted and distressed (MID) areas. Funds must be used for costs related to unmet needs in the MID areas resulting from qualifying disasters. HUD allocates funds using the best available data that cover the eligible affected areas and identifies MID areas. Grantees are required to use 80 percent of all CDBG–DR funds to benefit the HUD-identified MID areas. The HUD-identified MID areas and the minimum dollar amount that must be spent to benefit those areas will be identified for each grantee in the applicable Allocation Announcement Notice. If a grantee seeks to add other areas to the HUD-identified MID area, the grantee must contact its CPD Representative or CPD Specialist and submit the request with a data-driven analysis that illustrates the basis for designating the additional area as most impacted and distressed as a result of the qualifying disaster.

Grantees may use up to five percent of the total grant award for grant administration. Therefore, HUD will include 80 percent of a grantee's expenditures for grant administration in its determination that 80 percent of the total award has benefited the HUD-identified MID area. Expenditures for planning activities may also be counted towards the HUD-identified MID area requirement, if the grantee describes in its action plan how those planning activities benefit those areas.

HUD may identify an entire jurisdiction or a ZIP code as a MID area. If HUD designates a ZIP code as a MID area for the purposes of allocating funds, the grantee may expand program operations to the whole county or counties that overlap with the HUD designated ZIP code. A grantee must indicate the decision to expand eligibility to the whole county or counties in its action plan.

Grantees must determine where to use the remaining amount of the CDBG–DR grant, but

that portion of the allocation may only be used to address unmet needs and that benefit those areas that the grantee determines are most impacted and distressed (“grantee-identified MID areas”) within areas that received a presidential major disaster declaration identified by the disaster numbers listed in the applicable Allocation Announcement Notice. The grantee must use quantifiable and verifiable data in its analysis, as referenced in its action plan, to identify the MID areas where it will use the remaining amount of CDBG–DR funds.

Grantee expenditures for eligible unmet needs outside of the HUD-identified or grantee-identified MID areas are allowable, provided that the grantee can demonstrate how the expenditure of CDBG–DR funds outside of the MID areas will address unmet needs identified within the HUD-identified or grantee-identified MID area (e.g., upstream water retention projects to reduce downstream flooding in the HUD-identified MID area).

II.B. Housing Activities and Related Floodplain Issues

Grantees may use CDBG–DR funds for activities that may include, but are not limited to, new construction, reconstruction, and rehabilitation of single-family or multifamily housing, homeownership assistance, buyouts, and rental assistance. The broadening of eligible CDBG–DR activities related to housing under the HCDA is necessary following major disasters in which housing, including large numbers of affordable housing units, have been damaged or destroyed. The following waivers and alternative requirements will assist grantees in addressing the full range of unmet housing needs arising from a disaster.

II.B.1. New housing construction waiver and alternative requirement. 42 U.S.C. 5305(a) and 24 CFR 570.207(b)(3) are waived to the extent necessary to permit new housing construction, subject to the following alternative requirement. When a CDBG–DR grantee carries out a new housing construction activity, 24 CFR 570.202 shall apply and shall be read to extend to new construction in addition to rehabilitation assistance. Private individuals and entities must remain compliant with federal accessibility requirements as well as with the applicable site selection requirements of 24 CFR 1.4(b)(3) and 8.4(b)(5).

II.B.2. Construction standards for new construction, reconstruction, and rehabilitation. HUD is adopting an alternative requirement to require grantees to adhere to the applicable construction standards in II.B.2.a. through II.B.2.d. when carrying out activities to construct, reconstruct, or rehabilitate residential structures with CDBG–DR funds as part of activities eligible under 42 U.S.C. 5305(a) (including activities authorized by waiver and alternative requirement). For purposes of the Consolidated Notice, the terms “substantial damage” and “substantial improvement” shall be as defined in 44 CFR 59.1 unless otherwise noted.

II.B.2.a. Green and resilient building standard for new construction and reconstruction of housing. Grantees must

meet the Green and Resilient Building Standard, as defined in this subparagraph, for: (i) all new construction and reconstruction (i.e., demolishing a housing unit and rebuilding it on the same lot in substantially the same manner) of residential buildings and (ii) all rehabilitation activities of substantially damaged residential buildings, including changes to structural elements such as flooring systems, columns, or load-bearing interior or exterior walls.

The Green and Resilient Building Standard requires that all construction covered by the paragraph above and assisted with CDBG–DR funds meet an industry-recognized standard that has achieved certification under (i) Enterprise Green Communities; (ii) LEED (New Construction, Homes, Midrise, Existing Buildings Operations and Maintenance, or Neighborhood Development); (iii) ICC–700 National Green Building Standard Green+ Resilience; (iv) Living Building Challenge; or (v) any other equivalent comprehensive green building program acceptable to HUD. Additionally, all such covered construction must achieve a minimum energy efficiency standard, such as (i) ENERGY STAR (Certified Homes or Multifamily High-Rise); (ii) DOE Zero Energy Ready Home; (iii) EarthCraft House, EarthCraft Multifamily; (iv) Passive House Institute Passive Building or EnerPHit certification from the Passive House Institute US (PHIUS), International Passive House Association; (v) Greenpoint Rated New Home, Greenpoint Rated Existing Home (Whole House or Whole Building label); (vi) Earth Advantage New Homes; or (vii) any other equivalent energy efficiency standard acceptable to HUD. Grantees must identify, in each project file, which of these Green and Resilient Building Standards will be used for any building subject to this paragraph. However, grantees are not required to use the same standards for each project or building.

II.B.2.b. Standards for rehabilitation of nonsubstantially damaged residential buildings. For rehabilitation other than the rehabilitation of substantially damaged residential buildings described in section II.B.2.a. above, grantees must follow the guidelines specified in the HUD CPD Green Building Retrofit Checklist.

Grantees must apply these guidelines to the extent applicable for the rehabilitation work undertaken, for example, the use of mold resistant products when replacing surfaces such as drywall. Products and appliances replaced as part of the rehabilitation work, must be ENERGY STAR-labeled, WaterSense-labeled, or Federal Energy Management Program (FEMP)-designated products or appliances.

II.B.2.c. Elevation standards for new construction, reconstruction, and rehabilitation of substantial damage, or rehabilitation resulting in substantial improvements. The following elevation standards apply to new construction, rehabilitation of substantial damage, or rehabilitation resulting in substantial improvement of residential structures located in an area delineated as a special flood hazard area or equivalent in FEMA’s data sources. 24 CFR 55.2(b)(1) provides additional information on data sources, which apply to all floodplain designations.

All structures, defined at 44 CFR 59.1, designed principally for residential use, and located in the one percent annual chance (or 100-year) floodplain, that receive assistance for new construction, reconstruction, rehabilitation of substantial damage, or rehabilitation that results in substantial improvement, as defined at 24 CFR 55.2(b)(10), must be elevated with the lowest floor, including the basement, at least two feet above the one percent annual chance floodplain elevation (base flood elevation). Mixed-use structures with no dwelling units and no residents below two feet above base flood elevation, must be elevated or floodproofed, in accordance with FEMA floodproofing standards at 44 CFR 60.3(c)(3)(ii) or successor standard, up to at least two feet above base flood elevation.

All Critical Actions, as defined at 24 CFR 55.2(b)(3), within the 500-year (or 0.2 percent annual chance) floodplain must be elevated or floodproofed (in accordance with FEMA floodproofing standards at 44 CFR 60.3(c)(2)–(3) or successor standard) to the higher of the 500-year floodplain elevation or three feet above the 100-year floodplain elevation. If the 500-year floodplain is unavailable, and the Critical Action is in the 100-year floodplain, then the structure must be elevated or floodproofed (in accordance with FEMA floodproofing standards at 44 CFR 60.3(c)(2)–(3) or successor standard) at least three feet above the 100-year floodplain elevation. Critical Actions are defined as “any activity for which even a slight chance of flooding would be too great, because such flooding might result in loss of life, injury to persons or damage to property.” For example, Critical Actions include hospitals, nursing homes, emergency shelters, police stations, fire stations, and principal utility lines.

In addition to other requirements in this section, grantees must comply with applicable state, local, and tribal codes and standards for floodplain management, including elevation, setbacks, and cumulative substantial damage requirements. Grantees using CDBG–DR funds as the non-Federal match in a FEMA-funded project may apply the alternative requirement for the elevation of structures described in section III.F.6. Structures that are elevated must meet federal accessibility standards.

II.B.2.d. Broadband infrastructure in housing. Any substantial rehabilitation, as defined by 24 CFR 5.100, reconstruction, or new construction of a building with more than four rental units must include installation of broadband infrastructure, except where the grantee documents that: (i) the location of the new construction or substantial rehabilitation makes installation of broadband infrastructure infeasible; (ii) the cost of installing broadband infrastructure would result in a fundamental alteration in the nature of its program or activity, or in an undue financial burden; or (iii) the structure of the housing to be substantially rehabilitated makes installation of broadband infrastructure infeasible.

II.B.3. Applicable affordability periods for new construction of affordable rental housing. To meet the low- and moderate-income housing national objective, rental

housing assisted with CDBG–DR funds must be rented to low- and moderate-income (LMI) households at affordable rents, and a grantee must define “affordable rents” in its action plan. Because the waiver and alternative requirement in II.B.1. authorizes the use of grant funds for new housing construction, HUD is imposing the following alternative requirement to modify the low- and moderate-income housing national objective criteria in 24 CFR 570.208(a)(3) and 570.483(b)(3) for activities involving the new construction of affordable rental housing of five or more units. For activities that will construct five or more units, in addition to other applicable criteria in 24 CFR 570.208(a)(3) and 570.483(b)(3), in its action plan, a grantee must define the affordability standards, including “affordable rents,” the enforcement mechanisms, and applicable timeframes, that will apply to the new construction of affordable rental housing, *i.e.*, when the activity will result in construction of five or more units, the affordability requirements described in the action plan apply to the units that will be occupied by LMI households. The minimum timeframes and other related requirements acceptable for compliance with this alternative requirement are the HOME Investment Partnerships Program (HOME) requirements at 24 CFR 92.252(e), including the table listing the affordability periods at the end of 24 CFR 92.252(e). Therefore, the grantee must adopt and implement enforceable affordability standards that comply with or exceed requirements at 24 CFR 92.252(e)(1) for the new construction of affordable rental housing in structures containing five or more units.

II.B.4. *Affordability period for new construction of homes built for LMI households.* In addition to alternative requirements in II.B.1., the following alternative requirement applies to activities to construct new single-family units for homeownership that will meet the LMI housing national objective criteria. Grantees must establish affordability restrictions on all newly constructed single-family housing (for purposes of the Consolidated Notice, single-family housing is defined as four units or less), that, upon completion, will be purchased and occupied by LMI homeowners. The minimum affordability period acceptable for compliance are the HOME requirements at 24 CFR 92.254(a)(4). If a grantee applies other standards, the periods of affordability applied by a grantee must meet or exceed the applicable HOME requirements in 24 CFR 92.254(a)(4) and the table of affordability periods directly following that provision. Grantees shall establish resale or recapture requirements for housing funded pursuant to this paragraph and shall describe those requirements in the action plan or substantial amendment in which the activity is proposed. The resale or recapture requirements must clearly describe the terms of resale or recapture and the specific circumstances under which resale or recapture will be used. Affordability restrictions must be enforceable and imposed by recorded deed restrictions, covenants, or other similar mechanisms. The affordability restrictions, including the affordability period requirements in this paragraph do not

apply to housing units newly constructed or reconstructed for an owner-occupant to replace the owner-occupant’s home that was damaged by the disaster.

II.B.5. *Homeownership assistance waiver and alternative requirement.* 42 U.S.C. 5305(a)(24) is waived and replaced with the following alternative requirement:

“Provision of direct assistance to facilitate and expand homeownership among persons at or below 120 percent of area median income (except that such assistance shall not be considered a public service for purposes of 42 U.S.C. 5305(a)(8)) by using such assistance to—

(A) subsidize interest rates and mortgage principal amounts for homebuyers with incomes at or below 120 percent of area median income;

(B) finance the acquisition of housing by homebuyers with incomes at or below 120 percent of area median income that is occupied by the homebuyers;

(C) acquire guarantees for mortgage financing obtained by homebuyers with incomes at or below 120 percent of area median income from private lenders, meaning that if a private lender selected by the homebuyer offers a guarantee of the mortgage financing, the grantee may purchase the guarantee to ensure repayment in case of default by the homebuyer. This subparagraph allows the purchase of mortgage insurance by the household but not the direct issuance of mortgage insurance by the grantee;

(D) provide up to 100 percent of any down payment required from homebuyers with incomes at or below 120 percent of area median income; or

(E) pay reasonable closing costs (normally associated with the purchase of a home) incurred by homebuyers with incomes at or below 120 percent of area median income.”

While homeownership assistance, as described above, may be provided to households with incomes at or below 120 percent of the area median income, HUD will only consider those funds used for households with incomes at or below 80 percent of the area median income to qualify as meeting the LMI person benefit national objective.

II.B.6. *Limitation on emergency grant payments—interim mortgage assistance.* 42 U.S.C. 5305(a)(8), 24 CFR 570.201(e), 24 CFR 570.207(b)(4), and 24 CFR 1003.207(b)(4) are modified to extend interim mortgage assistance (IMA) to qualified individuals from three months to up to twenty months. IMA must be used in conjunction with a buyout program, or the rehabilitation or reconstruction of single-family housing, during which mortgage payments may be due but the home is not habitable. A grantee using this alternative requirement must document, in its policies and procedures, how it will determine that the amount of assistance to be provided is necessary and reasonable.

II.B.7. *Buyout activities.* CDBG–DR grantees may carry out property acquisition for a variety of purposes, but buyouts are a type of acquisition for the specific purpose of reducing the risk of property damage. HUD

has determined that creating a new activity and alternative requirement for buyouts is necessary for consistency with the application of other Federal resources commonly used for this type of activity. Therefore, HUD is waiving 42 U.S.C. 5305(a) and establishing an alternative requirement only to the extent necessary to create a new eligible activity for buyouts. The term “buyouts” means the acquisition of properties located in a floodway, floodplain, or other Disaster Risk Reduction Area that is intended to reduce risk from future hazards. Grantees can designate a Disaster Risk Reduction Area, as defined below.

Grantees carrying out buyout activities must establish an open space management plan or equivalent, if one has not already been established, before implementation. The plan must establish full transparency about the planned use of acquired properties post-buyout, or the process by which the planned use will be determined and enforced.

Buyout activities are subject to all requirements that apply to acquisition activities generally including but not limited to, the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970 (URA) (42 U.S.C. 4601, *et seq.*) and its implementing regulations at 49 CFR part 24, subpart B, unless waived or modified by alternative requirements. Only acquisitions that meet the definition of a “buyout” are subject to the post-acquisition land use restrictions imposed by the alternative requirement (II.B.7.a. below). The key factor in determining whether the acquisition is a buyout is whether the intent of the purchase is to reduce risk of property damage from future flooding or other hazards in a floodway, floodplain, or a Disaster Risk Reduction Area. A grantee that will buyout properties in a Disaster Risk Reduction Area must establish criteria in its policies and procedures to designate an area as a Disaster Risk Reduction Area for the buyout, pursuant to the following requirements:

(1) the area has been impacted by the hazard that has been caused or exacerbated by the disaster for which the grantee received its CDBG–DR allocation;

(2) the hazard identified must be a predictable environmental threat to the safety and well-being of program beneficiaries, including members of protected classes, vulnerable populations, and underserved communities, as evidenced by the best available data (*e.g.*, FEMA Repetitive Loss Data, EPA’s Environmental Justice Screening and Mapping Tool, HHS’s climate change related guidance and data, etc.) and science (such as engineering and structural solutions propounded by FEMA, USACE, other federal agencies, etc.); and

(3) the area must be clearly delineated so that HUD and the public may easily determine which properties are located within the designated area.

Grantees may only redevelop an acquired property if the property is not acquired through a buyout program (*i.e.*, the purpose of acquisition was something other than risk reduction). When acquisitions are not acquired through a buyout program, the purchase price must be consistent with 2 CFR part 200, subpart E—Cost Principles

(“cost principles”) and the pre-disaster fair market value may not be used.

II.B.7.a. Buyout requirements:

(i) Property to be acquired or accepted must be located within a floodway, floodplain, or Disaster Risk Reduction Area.

(ii) Any property acquired or accepted must be dedicated and maintained in perpetuity for a use that is compatible with open space, recreational, floodplain and wetlands management practices, or other disaster-risk reduction practices.

(iii) No new structure will be erected on property acquired or accepted under the buyout program other than:

(a) a public facility that is open on all sides and functionally related to a designated open space (e.g., a park, campground, or outdoor recreation area);

(b) a restroom; or

(c) a flood control structure, provided that:

(1) the structure does not reduce valley storage, increase erosive velocities, or increase flood heights on the opposite bank, upstream, or downstream; and

(2) the local floodplain manager approves the structure, in writing, before commencement of construction of the structure.

(iv) After the purchase of a buyout property with CDBG-DR funds, the owner of the buyout property (including subsequent owners) is prohibited from making any applications to any Federal entity in perpetuity for additional disaster assistance for any purpose related to the property acquired through the CDBG-DR funded buyout, unless the assistance is for an allowed use as described in paragraph (ii) above. The entity acquiring the property may lease or sell it to adjacent property owners or other parties for compatible uses that comply with buyout requirements in return for a maintenance agreement.

(v) A deed restriction or covenant running with the property must require that the buyout property be dedicated and maintained for compatible uses that comply with buyout requirements in perpetuity.

(vi) Grantees must choose from one of two valuation methods (pre-disaster value or post-disaster value) for a buyout program (or a single buyout activity). The grantee must apply its valuation method for all buyouts carried out under the program. If the grantee determines the post-disaster value of a property is higher than the pre-disaster value, a grantee may provide exceptions to its established valuation method on a case-by-case basis. The grantee must describe the process for such exceptions and how it will analyze the circumstances to permit an exception in its buyout policies and procedures. Each grantee must adopt policies and procedures on how it will demonstrate that the amount of assistance for a buyout is necessary and reasonable.

(vii) All buyout activities must be classified using the “buyout” activity type in the Disaster Recovery and Grant Reporting (DRGR) system.

(viii) Any state grantee implementing a buyout program or activity must consult with local or tribal governments within the areas in which buyouts will occur.

II.B.8. Safe housing incentives in disaster-affected communities.

The limitation on eligible activities in section 42 U.S.C. 5305(a) is waived and HUD is establishing the following alternative requirement to establish safe housing incentives as an eligible activity. A safe housing incentive is any incentive provided to encourage households to relocate to suitable housing in a lower risk area or in an area promoted by the community’s comprehensive recovery plan. Displaced persons must receive any relocation assistance to which they are entitled under other legal authorities, such as the URA, section 104(d) of the HCDA, or those described in the Consolidated Notice. The grantee may offer safe housing incentives in addition to the relocation assistance that is legally required.

Grantees must maintain documentation, at least at a programmatic level, describing how the grantee determined the amount of assistance for the incentive was necessary and reasonable, how the incentive meets a national objective, and that the incentives are in accordance with the grantee’s approved action plan and published program design(s). A grantee may require the safe housing incentive to be used for a particular purpose by the household receiving the assistance. However, this waiver does not permit a compensation program meaning that funds may not be provided to a beneficiary to compensate the beneficiary for an estimated or actual amount of loss from the declared disaster. Grantees are prohibited from offering housing incentives to a homeowner as an incentive to induce the homeowner to sell a second home, consistent with the prohibition and definition of second home in section II.B.12.

II.B.9. National objectives for buyouts and safe housing incentives.

Activities that assist LMI persons and meet the criteria for the national objectives described below, including in II.B.10., will be considered to benefit LMI persons unless there is substantial evidence to the contrary and will count towards the calculation of a grantee’s overall LMI benefit requirement as described in section III.F.2. The grantee shall appropriately ensure that activities that meet the criteria for any of the national objectives below do not benefit moderate-income persons to the exclusion of low-income persons.

When undertaking buyout activities, to demonstrate that a buyout meets the low- and moderate-income housing (LMH) national objective, grantees must meet all requirements of the HCDA, and applicable regulatory criteria described below. 42 U.S.C. 5305(c)(3) provides that any assisted activity that involves the acquisition of property to provide housing shall be considered to benefit LMI persons only to the extent such housing will, upon completion, be occupied by such persons. In addition, 24 CFR 570.483(b)(3), 24 CFR 570.208(a)(3), and 24 CFR 1003.208(c) apply the LMH national objective to an eligible activity carried out for the purpose of providing or improving permanent residential structures that, upon completion, will be occupied by LMI households.

A buyout program that merely pays homeowners to leave their existing homes

does not guarantee that those homeowners will occupy a new residential structure. Therefore, acquisition-only buyout programs cannot satisfy the LMH national objective criteria.

To meet a national objective that benefits a LMI person, buyout programs can be structured in one of the following ways:

(1) The buyout activity combines the acquisition of properties with another direct benefit—LMI housing activity, such as down payment assistance—that results in occupancy and otherwise meets the applicable LMH national objective criteria;

(2) The activity meets the low- and moderate-income area (LMA) benefit criteria and documents that the acquired properties will have a use that benefits all the residents in a particular area that is primarily residential, where at least 51 percent of the residents are LMI persons. Grantees covered by the “exception criteria” as described in section IV.C. of the Consolidated Notice may apply it to these activities. To satisfy LMA criteria, grantees must define the service area based on the end use of the buyout properties; or

(3) The program meets the criteria for the low- and moderate-income limited clientele (LMC) national objective by restricting buyout program eligibility to exclusively LMI persons and benefiting LMI sellers by acquiring their properties for more than current fair market value (in accordance with the valuation requirements in section II.B.7.a.(vi)).

II.B.10. For LMI Safe Housing Incentive (LMHI). The following alternative requirement establishes new LMI national objective criteria that apply to safe housing incentive (LMHI) activities that benefit LMI households. HUD has determined that providing CDBG-DR grantees with an additional method to demonstrate how safe housing incentive activities benefit LMI households will ensure that grantees and HUD can account for and assess the benefit that CDBG-DR assistance for these activities has on LMI households.

The LMHI national objective may be used when a grantee uses CDBG-DR funds to carry out a safe housing incentive activity that benefits one or more LMI persons. To meet the LMHI national objective, the incentive must be (a.) tied to the voluntary acquisition of housing (including buyouts) owned by a qualifying LMI household and made to induce a move outside of the affected floodplain or disaster risk reduction area to a lower-risk area or structure; or (b.) for the purpose of providing or improving residential structures that, upon completion, will be occupied by a qualifying LMI household and will be in a lower risk area.

II.B.11. Redevelopment of acquired properties. Although properties acquired through a buyout program may not be redeveloped, grantees may redevelop other acquired properties. For non-buyout acquisitions, HUD has not permitted the grantee to base acquisition cost on pre-disaster fair market value. The acquisition cost must comply with applicable cost principles and with the acquisition requirements at 49 CFR 24, Subpart B, as revised by the Consolidated Notice waivers

and alternative requirements. In addition to the purchase price, grantees may opt to provide optional relocation assistance, as allowable under section 104 and 105 of the HCDA (42 U.S.C. 5304 and 42 U.S.C. 5305) and 24 CFR 570.606(d), and as expanded by section IV.F.5. of the Consolidated Notice, to the owner of a property that will be redeveloped if: (a.) the property is purchased by the grantee or subrecipient through voluntary acquisition; and (b.) the owner's need for additional assistance is documented. Any optional relocation assistance must provide equal relocation assistance within each class of displaced persons, including but not limited to providing reasonable accommodation exceptions to persons with disabilities. See 24 CFR 570.606(d) for more information on optional relocation assistance. In addition, tenants displaced by these voluntary acquisitions may be eligible for URA relocation assistance. In carrying out acquisition activities, grantees must ensure they are in compliance with the long-term redevelopment plans of the community in which the acquisition and redevelopment is to occur.

II.B.12. Alternative requirement for housing rehabilitation—assistance for second homes. HUD is instituting an alternative requirement to the rehabilitation provisions at 42 U.S.C. 5305(a)(4) as follows: properties that served as second homes at the time of the disaster, or following the disaster, are not eligible for rehabilitation assistance or safe housing incentives. This prohibition does not apply to acquisitions that meet the definition of a buyout. A second home is defined for purposes of the Consolidated Notice as a home that is not the primary residence of the owner, a tenant, or any occupant at the time of the disaster or at the time of application for CDBG–DR assistance. Grantees can verify a primary residence using a variety of documentation including, but not limited to, voter registration cards, tax returns, homestead exemptions, driver's licenses, and rental agreements. Acquisition of second homes at post-disaster fair market value is not prohibited.

II.C. Infrastructure (Public Facilities, Public Improvements), Match, and Elevation of Non-Residential Structures

HUD is adopting an alternative requirement to require grantees to adhere to the applicable construction standards and requirements in II.C.1., II.C.2. and II.C.4., which apply only to those eligible activities described in those paragraphs.

II.C.1. Infrastructure planning and design. All newly constructed infrastructure that is assisted with CDBG–DR funds must be designed and constructed to withstand extreme weather events and the impacts of climate change. To satisfy this requirement, the grantee must identify and implement resilience performance metrics as described in section II.A.2.

For purposes of this requirement, an infrastructure activity includes any activity or group of activities (including acquisition or site or other improvements), whether carried out on public or private land, that assists the development of the physical assets that are designed to provide or support

services to the general public in the following sectors: Surface transportation, including roadways, bridges, railroads, and transit; aviation; ports, including navigational channels; water resources projects; energy production and generation, including from renewable, nuclear, and hydro sources; electricity transmission; broadband; pipelines; stormwater and sewer infrastructure; drinking water infrastructure; schools, hospitals, and housing shelters; and other sectors as may be determined by the Federal Permitting Improvement Steering Council. For purposes of this requirement, an activity that falls within this definition is an infrastructure activity regardless of whether it is carried out under sections 105(a)(2), 105(a)(4), 105(a)(14), another section of the HCDA, or a waiver or alternative requirement established by HUD. Action plan requirements related to infrastructure activities are found in section II.C.1.e. of the Consolidated Notice.

II.C.2. Elevation of nonresidential structure. Nonresidential structures, including infrastructure, assisted with CDBG–DR funds must be elevated to the standards described in this paragraph or floodproofed, in accordance with FEMA floodproofing standards at 44 CFR 60.3(c)(3)(ii) or successor standard, up to at least two feet above the 100-year (or one percent annual chance) floodplain. All Critical Actions, as defined at 24 CFR 55.2(b)(3), within the 500-year (or 0.2 percent annual chance) floodplain must be elevated or floodproofed (in accordance with FEMA floodproofing standards at 44 CFR 60.3(c)(2)–(3) or successor standard) to the higher of the 500-year floodplain elevation or three feet above the 100-year floodplain elevation. If the 500-year floodplain or elevation is unavailable, and the Critical Action is in the 100-year floodplain, then the structure must be elevated or floodproofed at least three feet above the 100-year floodplain elevation. Activities subject to elevation requirements must comply with applicable federal accessibility mandates.

In addition to the other requirements in this section, the grantee must comply with applicable state, local, and tribal codes and standards for floodplain management, including elevation, setbacks, and cumulative substantial damage requirements. Grantees using CDBG–DR funds as the non-Federal match in a FEMA-funded project may apply the alternative requirement for the elevation of structures described in section IV.D.5.

II.C.3. CDBG–DR funds as match. As provided by the HCDA, grant funds may be used to satisfy a match requirement, share, or contribution for any other Federal program when used to carry out an eligible CDBG–DR activity. This includes programs or activities administered by the FEMA or the U.S. Army Corps of Engineers (USACE). By law, (codified in the HCDA as a note to section 105(a)) only \$250,000 or less of CDBG–DR funds may be used for the non-Federal cost-share of any project funded by USACE. Appropriations acts prohibit the use of CDBG–DR funds for any activity reimbursable by, or for which funds are also made available by FEMA or USACE.

In response to a disaster, FEMA may implement, and grantees may elect to follow, alternative procedures for FEMA's Public Assistance Program, as authorized pursuant to section 428 of the Robert T. Stafford Disaster Relief and Emergency Assistance Act ("Stafford Act"). Like other projects, grantees may use CDBG–DR funds as a matching requirement, share, or contribution for section 428 Public Assistance Projects. For all match activities, grantees must document that CDBG–DR funds have been used for the actual costs incurred for the assisted project and for costs that are eligible, meet a national objective, and meet other applicable CDBG requirements.

II.C.4. Requirements for flood control structures. Grantees that use CDBG–DR funds to assist flood control structures (*i.e.*, dams and levees) are prohibited from using CDBG–DR funds to enlarge a dam or levee beyond the original footprint of the structure that existed before the disaster event, without obtaining pre-approval from HUD and any Federal agencies that HUD determines are necessary based on their involvement or potential involvement with the levee or dam. Grantees that use CDBG–DR funds for levees and dams are required to: (1) register and maintain entries regarding such structures with the USACE National Levee Database or National Inventory of Dams; (2) ensure that the structure is admitted in the USACE PL 84–99 Program (Levee Rehabilitation and Inspection Program); (3) ensure the structure is accredited under the FEMA National Flood Insurance Program; (4) enter the exact location of the structure and the area served and protected by the structure into the DRGR system; and (5) maintain file documentation demonstrating that the grantee has conducted a risk assessment before funding the flood control structure and documentation that the investment includes risk reduction measures.

II.D. Economic Revitalization and Section 3 Requirements on Economic Opportunities

CDBG–DR funds can be used for CDBG–DR eligible activities related to economic revitalization. The attraction, retention, and return of businesses and jobs to a disaster-impacted area is critical to long-term recovery. Accordingly, for CDBG–DR purposes, economic revitalization may include any CDBG–DR eligible activity that demonstrably restores and improves the local economy through job creation and retention or by expanding access to goods and services. The most common CDBG–DR eligible activities to support economic revitalization are outlined in 24 CFR 570.203 and 570.204 and sections 105(a)(14), (15), and (17) of the HCDA.

Based on the U.S. Change Research Program's Fourth National Climate Assessment, climate-related natural hazards, extreme events, and natural disasters disproportionately affect LMI individuals who belong to underserved communities because they are less able to prepare for, respond to, and recover from the impacts of extreme events and natural hazards, or are members of communities that have experienced significant disinvestment and historic discrimination. Therefore, HUD is imposing the following alternative

requirement: When funding activities under section 105(a) of the HCDA that support economic revitalization, grantees must prioritize those underserved communities that have been impacted by the disaster and that were economically distressed before the disaster, as described further below in II.D.1.

The term “underserved communities” refers to populations sharing a particular characteristic, as well as geographic communities, that have been systematically denied a full opportunity to participate in aspects of economic, social, and civic life. Underserved communities that were economically distressed before the disaster include, but are not limited to, those areas that were designated as a Promise Zone, Opportunity Zone, a Neighborhood Revitalization Strategy Area, a tribal area, or those areas that meet at least one of the distress criteria established for the designation of an investment area of Community Development Financial Institution at 12 CFR 1805.201(b)(3)(ii)(D).

Grantees undertaking an economic revitalization activity must maintain supporting documentation to demonstrate how the grantee has prioritized underserved communities for purposes of its activities that support economic revitalization, as described below in II.D.1.

II.D.1. Prioritizing economic revitalization assistance—alternative requirement. When funding activities outlined in 24 CFR 570.203 and 570.204 and sections 105(a)(14), (15), and (17) of the HCDA, HUD is instituting an alternative requirement in addition to the other requirements in these provisions to require grantees to prioritize assistance to disaster-impacted businesses that serve underserved communities and spur economic opportunity for underserved communities that were economically distressed before the disaster.

II.D.2. National objective documentation for activities that support economic revitalization. 24 CFR 570.208(a)(4)(i)&(ii), 24 CFR 570.483(b)(4)(i)&(ii), 24 CFR 570.506(b)(5)&(6), and 24 CFR 1003.208(d) are waived to allow the grantees under the Consolidated Notice to identify the LMI jobs benefit by documenting, for each person employed, the name of the business, type of job, and the annual wages or salary of the job. HUD will consider the person income-qualified if the annual wages or salary of the job is at or under the HUD-established income limit for a one-person family. This method replaces the standard CDBG requirement—in which grantees must review the annual wages or salary of a job in comparison to the person’s total household income and size (*i.e.*, the number of persons). Thus, this method streamlines the documentation process by allowing the collection of wage data for each position created or retained from the assisted businesses, rather than from each individual household.

II.D.3. Public benefit for activities that support economic revitalization. When applicable, the public benefit provisions set standards for individual economic development activities (such as a single loan to a business) and for the aggregate of all economic development activities. Economic

development activities support economic revitalization. Currently, public benefit standards limit the amount of CDBG assistance per job retained or created, or the amount of CDBG assistance per LMI person to whom goods or services are provided by the activity. These dollar thresholds can impede recovery by limiting the amount of assistance the grantee may provide to a critical activity.

HUD waives the public benefit standards at 42 U.S.C. 5305(e)(3), 24 CFR 570.482(f)(1), (2), (3), (4)(i), (5), and (6), and 570.209(b)(1), (2), (3)(i), (4), and 24 CFR 1003.302(c) for all economic development activities. Paragraph (g) of 24 CFR 570.482 and paragraph (c) and (d) under 570.209 are also waived to the extent these provisions are related to public benefit. However, grantees that choose to take advantage of this waiver in lieu of complying with public benefit standards under the existing regulatory requirements shall be subject to the following condition: grantees shall collect and maintain documentation in the project file on the creation and retention of total jobs; the number of jobs within appropriate salary ranges, as determined by the grantee; the average amount of assistance provided per job, by activity or program; and the types of jobs. Additionally, grantees shall report the total number of jobs created and retained and the applicable national objective in the DRGR system.

II.D.4. Clarifying note on Section 3 worker eligibility and documentation requirements. Section 3 of the Housing and Urban Development Act of 1968 (12 U.S.C. 1701u) (section 3) applies to CDBG–DR activities that are section 3 projects, as defined at 24 CFR 75.3(a)(2). The purpose of section 3 is to ensure that economic opportunities, most importantly employment, generated by certain HUD financial assistance shall be directed to low- and very low-income persons, particularly those who are recipients of government assistance for housing or residents of the community in which the Federal assistance is spent. CDBG–DR grantees are directed to HUD’s guidance published in CPD Notice 2021–09, “Section 3 of the Housing and Urban Development Act of 1968, as amended by the Housing and Community Development Act of 1992, final rule requirements for CDBG, CDBG–CV, CDBG–DR, CDBG–Mitigation (CDBG–MIT), NSP, section 108, and RHP projects,” as amended (<https://www.hud.gov/sites/dfiles/OCHCO/documents/2021-09cpdn.pdf>). All direct recipients of CDBG–DR funding must report section 3 information through the DRGR system.

II.D.5. Waiver and modification of the job relocation clause to permit assistance to help a business return. CDBG requirements prevent program participants from providing assistance to a business to relocate from one labor market area to another if the relocation is likely to result in a significant loss of jobs in the labor market from which the business moved. This prohibition can be a critical barrier to reestablishing and rebuilding a displaced employment base after a major disaster. Therefore, 42 U.S.C. 5305(h), 24 CFR 570.210, 24 CFR 570.482(h), and 24 CFR 1003.209, are waived to allow a grantee to provide assistance to any business that was

operating in the disaster-declared labor market area before the incident date of the applicable disaster and has since moved, in whole or in part, from the affected area to another state or to another labor market area within the same state to continue business.

II.D.6. Underwriting. Notwithstanding section 105(e)(1) of the HCDA, no CDBG–DR funds may be provided to a for-profit entity for an economic development project under section 105(a)(17) of the HCDA unless such project has been evaluated and selected in accordance with guidelines developed by HUD pursuant to section 105(e)(2) of the HCDA for evaluating and selecting economic development projects. Grantees and their subrecipients are required to comply with the underwriting guidelines in Appendix A to 24 CFR part 570 if they are using grant funds to provide assistance to a for-profit entity for an economic development project under section 105(a)(17) of the HCDA. The underwriting guidelines are found at Appendix A of 24 CFR part 570.

II.D.7. Limitation on use of funds for eminent domain. CDBG–DR funds may not be used to support any Federal, state, or local projects that seek to use the power of eminent domain, unless eminent domain is employed only for a public use. For purposes of this paragraph, public use shall not be construed to include economic development that primarily benefits private entities. The following shall be considered a public use for the purposes of eminent domain: any use of funds for (1) mass transit, railroad, airport, seaport, or highway projects; (2) utility projects that benefit or serve the general public, including energy related, communication-related, water related, and wastewater-related infrastructure; (3) other structures designated for use by the general public or which have other common-carrier or public-utility functions that serve the general public and are subject to regulation and oversight by the government; and (4) projects for the removal of an immediate threat to public health and safety, including the removal of a brownfield as defined in the Small Business Liability Relief and Brownfields Revitalization Act (Pub. L. 107–118).

III. Grant Administration

III.A. Pre-Award Evaluation of Management and Oversight of Funds

III.A.1. Certification of financial controls and procurement processes, and adequate procedures for proper grant management. Appropriations acts require that the Secretary certify that the grantee has in place proficient financial controls and procurement processes and has established adequate procedures to prevent any duplication of benefits as defined by section 312 of the Stafford Act, 42 U.S.C. 5155, to ensure timely expenditure of funds, to maintain a comprehensive website regarding all disaster recovery activities assisted with these funds, and to detect and prevent waste, fraud, and abuse of funds.

III.A.1.a. Documentation requirements. To enable the Secretary to make this certification, each grantee must submit to HUD the certification documentation listed below. This information must be submitted within 60 days of the applicability date of the

Allocation Announcement Notice, or with the grantee's submission of its action plan in DRGR as described in section III.C.1, whichever date is earlier. If required by appropriations acts, grant agreements will not be executed until the Secretary has issued a certification for the grantee. For each of the items (1) through (6) below (collectively referred to as the "Financial Management and Grant Compliance Certification Requirements") the grantee must certify to the accuracy of its submission when submitting the Financial Management and Grant Compliance Certification Checklist (the "Certification Checklist"). The Certification Checklist is a document that incorporates all of the Financial Management and Grant Compliance Certification Requirements. Not all of the requirements in (1) through (6) below are appropriate or applicable to Indian tribes. Therefore, Indian tribes that receive an allocation directly from HUD may request an alternative method to document support for the Secretary's certification.

(1) Proficient financial management controls. A grantee has proficient financial management controls if each of the following criteria is satisfied:

(a) The grantee agency administering this grant submits its most recent single audit and consolidated annual financial report (CAFR), which in HUD's determination indicates that the grantee has no material weaknesses, deficiencies, or concerns that HUD considers to be relevant to the financial management of CDBG, CDBG-DR, or CDBG-MIT funds. If the single audit or CAFR identified weaknesses or deficiencies, the grantee must provide documentation satisfactory to HUD showing how those weaknesses have been removed or are being addressed.

(b) The grantee has completed and submitted the certification documentation required in the applicable Certification Checklist. The grantee's documentation must demonstrate that the standards meet the requirements in the Consolidated Notice and the Certification Checklist.

(2) Each grantee must provide HUD its procurement processes for review, so HUD may evaluate the grantee's processes to determine that they are based on principles of full and open competition. A grantee's procurement processes must comply with the procurement requirements at section IV.B.

(a) A state grantee has proficient procurement processes if HUD determines that its processes uphold the principles of full and open competition and include an evaluation of the cost or price of the product or service, and if its procurement processes reflect that it:

- (i) adopted 2 CFR 200.318 through 200.327;
- (ii) follows its own state procurement policies and procedures and establishes requirements for procurement processes for local governments and subrecipients based on full and open competition pursuant to 24 CFR 570.489(g), and the requirements for the state, its local governments, and subrecipients include evaluation of the cost or price of the product or service; or
- (iii) adopted 2 CFR 200.317, meaning that it will follow its own state procurement processes and evaluate the cost or price of

the product or service, but impose 2 CFR 200.318 through 200.327 on its subrecipients.

(b) A local government grantee has proficient procurement processes if the processes are consistent with the specific applicable procurement standards identified in 2 CFR 200.318 through 200.327. When the grantee provides a copy of its procurement processes, it must indicate the sections that incorporate these provisions.

(c) An Indian tribe grantee has proficient procurement processes if its procurement standards are consistent with procurement requirements in 2 CFR part 200 imposed by 24 CFR 1003.501, and additional procurement requirements in 1003.509(e) and 1003.510.

(3) Duplication of benefits. A grantee has adequate policies and procedures to prevent the duplication of benefits (DOB) if the grantee submits and identifies a uniform process that reflects the requirements in section IV.A of the Consolidated Notice, including:

(a) determining all disaster assistance received by the grantee or applicant and all reasonably identifiable financial assistance available to the grantee or applicant, as applicable, before committing funds or awarding assistance;

(b) determining a grantee's or an applicant's unmet need(s) for CDBG-DR assistance before committing funds or awarding assistance; and

(c) requiring beneficiaries to enter into a signed agreement to repay any duplicative assistance if they later receive additional assistance for the same purpose for which the CDBG-DR award was provided. The grantee must identify a method to monitor compliance with the agreement for a reasonable period (*i.e.*, a time period commensurate with risk) and must articulate this method in its policies and procedures, including the basis for the period during which the grantee will monitor compliance. This agreement must also include the following language: "Warning: Any person who knowingly makes a false claim or statement to HUD or causes another to do so may be subject to civil or criminal penalties under 18 U.S.C. 2, 287, 1001 and 31 U.S.C. 3729."

Policies and procedures of the grantee submitted to support the certification must provide that before the award of assistance, the grantee will use the best, most recent available data from FEMA, the Small Business Administration (SBA), insurers, and any other sources of local, state, and Federal sources of funding to prevent the duplication of benefits.

(4) Timely expenditures. A grantee has adequate policies and procedures to determine timely expenditures if it submits policies and procedures that indicate the following to HUD: how it will track and document expenditures of the grantee and its subrecipients (both actual and projected reported in performance reports); how it will account for and manage program income; how it will reprogram funds in a timely manner for activities that are stalled; and how it will project expenditures of all CDBG-DR funds within the period provided for in section V.A.

(5) Comprehensive disaster recovery website. A grantee has adequate policies and procedures to maintain a comprehensive accessible website if it submits policies and procedures indicating to HUD that the grantee will have a separate web page dedicated to its disaster recovery activities assisted with CDBG-DR funds that includes the information described at section III.D.1.d.—e. The procedures must also indicate the frequency of website updates. At minimum, grantees must update their website quarterly.

(6) Procedures to detect and prevent fraud, waste, and abuse. A grantee has adequate procedures to detect and prevent fraud, waste, and abuse if it submits procedures that indicate:

(a) how the grantee will verify the accuracy of information provided by applicants;

(b) the criteria to be used to evaluate the capacity of potential subrecipients;

(c) the frequency with which the grantee will monitor other agencies of the grantee that will administer CDBG-DR funds, and how it will monitor subrecipients, contractors, and other program participants, and why monitoring is to be conducted and which items are to be monitored;

(d) it has or will hire an internal auditor that provides both programmatic and financial oversight of grantee activities, and has adopted policies that describes the auditor's role in detecting fraud, waste, and abuse, which policies must be submitted to HUD;

(e) (i) for states or grantees subject to the same requirements as states, a written standard of conduct and conflicts of interest policy that complies with the requirements of 24 CFR 570.489(g) and (h) and subparagraph III.A.1.a(2)(a) of the Consolidated Notice, which policy includes the process for promptly identifying and addressing such conflicts;

(ii) for units of general local government or grantees subject to the same requirements as units of general local government, a written standard of conduct and conflicts of interest policy that complies with 24 CFR 570.611 and 2 CFR 200.318, as applicable, which includes the process for promptly identifying and addressing such conflicts;

(iii) for Indian tribes, a written standard of conduct and conflicts of interest policy that complies with 24 CFR 1003.606, as applicable; and

(f) it assists in investigating and taking action when fraud occurs within the grantee's CDBG-DR activities and/or programs. All grantees receiving CDBG-DR funds for the first time shall attend and require subrecipients to attend fraud related training provided by HUD OIG, when offered, to assist in the proper management of CDBG-DR grant funds. Instances of fraud, waste, and abuse should be referred to the HUD OIG Fraud Hotline (phone: 1-800-347-3735 or email: hotline@hudoig.gov).

Following a disaster, property owners and renters are frequently the targets of persons fraudulently posing as government employees, creditors, mortgage servicers, insurance adjusters, and contractors. The grantee's procedures must address how the grantee will make CDBG-DR beneficiaries

aware of the risks of contractor fraud and other potentially fraudulent activity that can occur in communities recovering from a disaster. Grantees must provide CDBG–DR beneficiaries with information that raises awareness of possible fraudulent activity, how the fraud can be avoided, and what local or state agencies to contact to take action and protect the grantee and beneficiary investment. The grantee's procedures must address the steps it will take to assist a CDBG–DR beneficiary if the beneficiary experiences contractor or other fraud. If the beneficiary is eligible for additional assistance as a result of the fraudulent activity and the creation of remaining unmet need, the procedures must also address what steps the grantee will follow to provide the additional assistance.

III.A.1.b. Relying on prior submissions—financial management and grant compliance certification requirements. This section only applies once a grantee has received a CDBG–DR grant through an Allocation Announcement Notice that makes the Consolidated Notice applicable. After that original grant, if a CDBG–DR grantee is awarded a subsequent CDBG–DR grant, HUD will rely on the grantee's prior submissions provided in response to the Financial Management and Grant Compliance Certification Requirements in the Consolidated Notice. HUD will continue to monitor the grantee's submissions and updates made to policies and procedures during the normal course of business. The grantee must notify HUD of any substantial changes made to these submissions.

If a CDBG–DR grantee is awarded a subsequent CDBG–DR grant, and it has been more than three years since the executed grant agreement for the original CDBG–DR grant or a subsequent grant is equal to or greater than ten times the amount of the original CDBG–DR grant, grantees must update and resubmit the documentation required by paragraph III.A.1.a. with the completed Certification Checklist to enable the Secretary to certify that the grantee has in place proficient financial controls and procurement processes, and adequate procedures for proper grant management. However, the Secretary may require any CDBG–DR grantee to update and resubmit the documentation required by paragraph III.A.1.a., if there is good cause to require it.

III.A.2. Implementation plan. HUD requires each grantee to demonstrate that it has sufficient capacity to manage the CDBG–DR funds and the associated risks. Grantees must evidence their management capacity through their implementation plan submissions. These submissions must meet the criteria below and must be submitted within 120 days of the applicability date of the governing Allocation Announcement Notice or with the grantee's submission of its action plan, whichever is earlier, unless the grantee has requested, and HUD has approved an extension of the submission deadline.

III.A.2.a. To enable HUD to assess risk as described in 2 CFR 200.206, the grantee will submit an implementation plan to HUD. The implementation plan must describe the grantee's capacity to carry out the recovery and how it will address any capacity gaps.

HUD will determine that the grantee has sufficient management capacity to adequately reduce risk if the grantee submits implementation plan documentation that addresses (1) through (3) below:

(1) **Capacity assessment.** The grantee identifies the lead agency responsible for implementation of the CDBG–DR award and indicates that the head of that agency will report directly to the chief executive officer of the jurisdiction. The grantee has conducted an assessment of its capacity to carry out CDBG–DR recovery efforts and has developed a timeline with milestones describing when and how the grantee will address all capacity gaps that are identified. The assessment must include a list of any open CDBG–DR findings and an update on the corrective actions undertaken to address each finding.

(2) **Staffing.** The grantee must submit an organizational chart of its department or division and must also provide a table that clearly indicates which personnel or organizational unit will be responsible for each of the Financial Management and Grant Compliance Certification Requirements identified in section III.A.1.a. along with staff contact information, if available (*i.e.*, personnel responsible for conducting DOB analysis, timely expenditure, website management, monitoring and compliance, and financial management). The grantee must also submit documentation demonstrating that it has assessed staff capacity and identified positions for the purpose of: case management in proportion to the applicant population; program managers who will be assigned responsibility for each primary recovery area; staff who have demonstrated experience in housing, infrastructure (as applicable), and economic revitalization (as applicable); staff responsible for procurement/contract management, regulations implementing section 3 of the Housing and Urban Development Act of 1968, as amended (24 CFR part 75) (section 3), fair housing compliance, and environmental compliance. An adequate plan must also demonstrate that the internal auditor and responsible audit staff report independently to the chief elected or executive officer or board of the governing body of any designated administering entity.

The grantee's implementation plan must describe how it will provide technical assistance for any personnel that are not employed by the grantee at the time of action plan submission, and to fill gaps in knowledge or technical expertise required for successful and timely recovery. State grantees must also include how it plans to provide technical assistance to subgrantees and subrecipients, including units of general local government.

(3) **Internal and interagency coordination.** The grantee's plan must describe how it will ensure effective communication between different departments and divisions within the grantee's organizational structure that are involved in CDBG–DR-funded recovery efforts, mitigation efforts, and environmental review requirements, as appropriate; between its lead agency and subrecipients responsible for implementing the grantee's action plan; and with other local and regional planning

efforts to ensure consistency. The grantee's submissions must demonstrate how it will consult with other relevant government agencies, including the State Hazard Mitigation Officer (SHMO), State or local Disaster Recovery Coordinator, floodplain administrator, and any other state and local emergency management agencies, such as public health and environmental protection agencies, that have primary responsibility for the administration of FEMA or USACE funds.

III.A.2.b. Relying on prior submissions—Implementation plan. This section only applies once a grantee has received a CDBG–DR grant through an Allocation Announcement Notice that makes the Consolidated Notice applicable. After that original grant, if a CDBG–DR grantee is awarded a subsequent CDBG–DR grant, HUD will rely on the grantee's implementation plan submitted for its original CDBG–DR grant unless it has been more than three years since the executed grant agreement for the original CDBG–DR grant or the subsequent grant is equal to or greater than ten times the amount of its original CDBG–DR grant.

If a CDBG–DR grantee is awarded a subsequent CDBG–DR grant, and it has been more than three years since the executed grant agreement for its original CDBG–DR grant or a subsequent grant is equal to or greater than ten times the amount of the original CDBG–DR grant, the grantee is to update and resubmit its implementation plan to reflect any changes to its capacity, staffing, and coordination.

III.B. Administration, Planning, and Financial Management

III.B.1. Grant administration and planning.

III.B.1.a. Grantee responsibilities. Each grantee shall administer its award in compliance with all applicable laws and regulations and shall be financially accountable for the use of all awarded funds. CDBG–DR grantees must comply with the recordkeeping requirements of 24 CFR 570.506 and 24 CFR 570.490, as amended by the Consolidated Notice waivers and alternative requirements. All grantees must maintain records of performance in DRGR, as described elsewhere in the Consolidated Notice.

III.B.1.b. Grant administration cap. Up to five percent of the grant (plus five percent of program income generated by the grant) can be used for administrative costs by the grantee, units of general local government, or subrecipients. Thus, the total of all costs classified as administrative for a CDBG–DR grant must be less than or equal to the five percent cap (plus five percent of program income generated by the grant). The cap for administrative costs is subject to the combined technical assistance and administrative cap for state grantees as discussed in section III.B.2.a.

III.B.1.c. Use of funds for administrative costs across multiple grants. The Additional Supplemental Appropriations for Disaster Relief Act, 2019 (Pub. L. 116–20) authorized special treatment for eligible administrative costs for grantees that received awards under Public Laws 114–113, 114–223, 114–254, 115–31, 115–56, 115–123, 115–254, 116–20, or any future act. The Consolidated Notice

permits grantees to use eligible administrative funds (up to five percent of each grant award plus up to five percent of program income generated by the grant) for the cost of administering any of these grants awarded under the identified Public Laws (including future Acts) without regard to the particular disaster appropriation from which such funds originated. To exercise this authority, the grantee must ensure that it has appropriate financial controls to guarantee that the amount of grant administration expenditures for each of the aforementioned grants will not exceed five percent of the total grant award for each grant (plus five percent of program income generated by the grant). The grantee must review and modify any financial management policies and procedures regarding the tracking and accounting of administration costs as necessary.

III.B.1.d. *Planning expenditures cap.* Both state and local government grantees are limited to spending a maximum of fifteen percent of their total grant amount on planning costs. Planning costs subject to the 15 percent cap are those defined in 42 U.S.C. 5305(a)(12) and more broadly in 24 CFR 570.205.

III.B.2. *State grantees only.*

III.B.2.a. *Combined technical assistance and administrative cap (state grantees only).* The provisions of 42 U.S.C. 5306(d) and 24 CFR 570.489(a)(1)(i) and (iii), and 24 CFR 570.489(a)(2) shall not apply to the extent that they cap administration and technical assistance expenditures, limit a state's ability to charge a nominal application fee for grant applications for activities the state carries out directly, and require a dollar-for-dollar match of state funds for administrative costs exceeding \$100,000. 42 U.S.C. 5306(d)(5) and (6) are waived and replaced with the alternative requirement that the aggregate total for administrative and technical assistance expenditures must not exceed five percent of the grant, plus five percent of program income generated by the grant.

III.B.2.b. *Planning-only activities (state grantees only).* The State CDBG Program requires that, for planning-only grants, local government grant recipients must document that the use of funds meets a national objective. In the CDBG Entitlement Program, these more general planning activities are presumed to meet a national objective under the requirements at 24 CFR 570.208(d)(4). HUD notes that almost all effective recoveries in the past have relied on some form of area-wide or comprehensive planning activity to guide overall redevelopment independent of the ultimate source of implementation funds. To assist state grantees, HUD is waiving the requirements at 24 CFR 570.483(b)(5) and (c)(3), which limit the circumstances under which the planning activity can meet a low-and-moderate-income or slum-and-bligh national objective. Instead, as an alternative requirement, 24 CFR 570.208(d)(4) applies to states when funding disaster recovery-assisted, planning-only grants, or when directly administering planning activities that guide disaster recovery. In addition, 42 U.S.C. 5305(a)(12) is waived to the extent necessary so the types of planning activities that states may fund or undertake are

expanded to be consistent with those of CDBG Entitlement grantees identified at 24 CFR 570.205.

III.B.2.c. *Direct grant administration and means of carrying out eligible activities (state grantees only).* Requirements at 42 U.S.C. 5306(d) are waived to allow a state to use its disaster recovery grant allocation directly to carry out state-administered activities eligible under the Consolidated Notice, rather than distribute all funds to local governments. Pursuant to this waiver and alternative requirement, the standard at 24 CFR 570.480(c) and the provisions at 42 U.S.C. 5304(e)(2) will also include activities that the state carries out directly. Activities eligible under the Consolidated Notice may be carried out by a state, subject to state law and consistent with the requirement of 24 CFR 570.200(f), through its employees, through procurement contracts, or through assistance provided under agreements with subrecipients. State grantees continue to be responsible for civil rights, labor standards, and environmental protection requirements, for compliance with 24 CFR 570.489(g) and (h), and subparagraph III.A.1.a.(2)(a) of the Consolidated Notice relating to conflicts of interest, and for compliance with 24 CFR 570.489(m) relating to monitoring and management of subrecipients.

A state grantee may also carry out activities in tribal areas. A state must coordinate with the Indian tribe with jurisdiction over the tribal area when providing CDBG-DR assistance to beneficiaries in tribal areas. State grantees carrying out projects in tribal areas, either directly or through its employees, through procurement contracts, or through assistance provided under agreements with subrecipients, must obtain the consent of the Indian tribe with jurisdiction over the tribal area to allow the state grantee to carry out or to fund CDBG-DR projects in the area.

III.B.2.d. *Waiver and alternative requirement for distribution to CDBG metropolitan cities and urban counties (state grantees only).* 42 U.S.C. 5302(a)(7) (definition of "nonentitlement area") and related provisions of 24 CFR part 570, including 24 CFR 570.480, are waived to permit state grantees to distribute CDBG-DR funds to units of local government and Indian tribes.

III.B.2.e. *Use of subrecipients (state grantees only).* Paragraph III.B.2.c. provides a waiver and alternative requirement that a state may carry out activities directly, including through assistance provided under agreements with subrecipients. Therefore, when states carry out activities directly through subrecipients, the following alternative requirements apply: the state is subject to the definition of subrecipients at 24 CFR 570.500(c) and must adhere to the requirements for agreements with subrecipients at 24 CFR 570.503. Additionally, 24 CFR 570.503(b)(4) is modified to require the subrecipient to comply with applicable uniform requirements, as described in 24 CFR 570.502, except that the subrecipient shall follow procurement requirements imposed by the state in accordance with subparagraph III.A.1.a.(2) of the Consolidated Notice. When

24 CFR 570.503 applies, notwithstanding 24 CFR 570.503(b)(5)(i), units of general local government that are subrecipients are defined as recipients under 24 CFR part 58 and are therefore responsible entities that assume environmental review responsibilities, as described in III.F.5. Grantees are reminded that they are responsible for providing on-going oversight and monitoring of subrecipients and are ultimately responsible for subrecipient compliance with all CDBG-DR requirements.

III.B.2.f. *Recordkeeping (state grantees only).* When a state carries out activities directly, 24 CFR 570.490(b) is waived and the following alternative provision shall apply: a state grantee shall establish and maintain such records as may be necessary to facilitate review and audit by HUD of the state's administration of CDBG-DR funds, under 24 CFR 570.493 and reviews and audits by the state under III.B.2.h. Consistent with applicable statutes, regulations, waivers and alternative requirements, and other Federal requirements, the content of records maintained by the state shall be sufficient to: (a) enable HUD to make the applicable determinations described at 24 CFR 570.493; (b) make compliance determinations for activities carried out directly by the state; and (c) show how activities funded are consistent with the descriptions of activities proposed for funding in the action plan and/or DRGR system. For fair housing and equal opportunity purposes, and as applicable, such records shall include data on the racial, ethnic, and gender characteristics of persons who are applicants for, participants in, or beneficiaries of the program.

III.B.2.g. *Change of use of real property (state grantees only).* This alternative requirement conforms the change of use of real property rule to the waiver allowing a state to carry out activities directly. For purposes of these grants, all references to "unit of general local government" in 24 CFR 570.489(j), shall be read as "state, local governments, or Indian tribes (either as subrecipients or through a method of distribution), or other state subrecipient."

III.B.2.h. *Responsibility for review and handling of noncompliance (state grantees only).* This change is in conformance with the waiver allowing a state to carry out activities directly. 24 CFR 570.492 is waived, and the following alternative requirement applies for any state receiving a direct award: the state shall make reviews and audits, including on-site reviews of any local governments or Indian tribes (either as subrecipients or through a method of distribution) designated public agencies, and other subrecipients, as may be necessary or appropriate to meet the requirements of section 104(e)(2) of the HCDA, as amended, and as modified by the Consolidated Notice. In the case of noncompliance with these requirements, the state shall take such actions as may be appropriate to prevent a continuance of the deficiency, mitigate any adverse effects or consequences, and prevent a recurrence. The state shall establish remedies for noncompliance by any subrecipients, designated public agencies, or local governments.

III.B.2.i. *Consultation (state grantees only).* Currently, the HCDA and regulations require

a state grantee to consult with affected local governments in nonentitlement areas of the state in determining the state's proposed method of distribution. HUD is waiving 42 U.S.C. 5306(d)(2)(C)(iv), 42 U.S.C. 5306(d)(2)(D), 24 CFR 91.325(b)(2), and 24 CFR 91.110, and imposing an alternative requirement that states receiving an allocation of CDBG–DR funds consult with all disaster-affected local governments (including any CDBG-entitlement grantees), Indian tribes, and any public housing authorities in determining the use of funds. This approach ensures that a state grantee sufficiently assesses the recovery needs of all areas affected by the disaster.

III.C. Action Plan for Disaster Recovery Waiver and Alternative Requirement

Requirements for CDBG actions plans, located at 42 U.S.C. 5304(a)(1), 42 U.S.C. 5304(m), 42 U.S.C. 5306(a)(1), 42 U.S.C. 5306(d)(2)(C)(iii), 42 U.S.C. 12705(a)(2), and 24 CFR 91.220 and 91.320, are waived for CDBG–DR grants. Instead, grantees must submit to HUD an action plan for disaster recovery which will describe programs and activities that conform to applicable requirements as specified in the Consolidated Notice and the applicable Allocation Announcement Notice. HUD will monitor the grantee's actions and use of funds for consistency with the plan, as well as meeting the performance and timeliness objectives therein. The Secretary will disapprove all action plans that are substantially incomplete if it is determined that the plan does not satisfy all of the required elements identified in the Consolidated Notice and the applicable Allocation Announcement Notice.

III.C.1. *Action plan.* The grantee's action plan must identify the use of all funds—including criteria for eligibility and how the uses address long-term recovery needs, restoration of infrastructure and housing, economic revitalization, and the incorporation of mitigation measures in the MID areas. HUD created the Public Action Plan in DRGR which is a function that allows grantees to develop and submit their action plans for disaster recovery directly into DRGR. Grantees must use HUD's Public Action Plan in DRGR to develop all CDBG–DR action plans and substantial amendments submitted to HUD for approval. The Public Action Plan is different from the DRGR Action Plan, which is a comprehensive description of projects and activities in DRGR.

The grantee must describe the steps it will follow to make the action plan, substantial amendments, performance reports, and other relevant program materials available in a form accessible to persons with disabilities and those with limited English proficiency (LEP). All grantees must include sufficient information in its action plan so that all interested parties will be able to understand and comment on the action plan. The action plan (and subsequent amendments) must include a single chart or table that illustrates, at the most practical level, how all funds are budgeted (*e.g.*, by program, subrecipient, grantee-administered activity, or other category). The grantee must certify, as required by section III.F.7., that activities to

be undertaken with CDBG–DR funds are consistent with its action plan.

The action plan must contain:

III.C.1.a. *An impact and unmet needs assessment.* Each grantee must develop an impact and unmet needs assessment to understand the type and location of community needs and to target limited resources to those areas with the greatest need. CDBG–DR grantees must conduct an impact and unmet needs assessment to inform the use of the grant. Grantees must cite data sources in the impact and unmet needs assessment. At a minimum, the impact and unmet needs assessment must:

- Evaluate all aspects of recovery including housing (interim and permanent, owner and rental, single family and multifamily, affordable and market rate, and housing to meet the needs of persons who were experiencing homelessness pre-disaster), infrastructure, and economic revitalization needs, while also incorporating mitigation needs into activities that support recovery as required in section II.A.2.;

- Estimate unmet needs to ensure CDBG–DR funds meet needs that are not likely to be addressed by other sources of funds by accounting for the various forms of assistance available to, or likely to be available to, affected communities (*e.g.*, projected FEMA funds) and individuals (*e.g.*, estimated insurance) and, using the most recent available data, estimating the portion of need unlikely to be addressed by insurance proceeds, other Federal assistance, or any other funding sources;

- Assess whether public services (*e.g.*, housing counseling, legal advice and representation, job training, mental health, and general health services) are necessary to complement activities intended to address housing, infrastructure, and economic revitalization and how those services would need to be made accessible to individuals with disabilities including, but not limited to, mobility, sensory, developmental, emotional, cognitive, and other impairments;

- Describe the extent to which expenditures for planning activities, including the determination of land use goals and policies, will benefit the HUD-identified MID areas, as described in section II.A.3.;

- Describe disaster impacts geographically by type at the lowest level practicable (*e.g.*, county/parish level or lower if available for states, and neighborhood or census tract level for cities); and

- Take into account the costs and benefits of incorporating hazard mitigation measures to protect against the specific identified impacts of future extreme weather events and other natural hazards. This analysis should factor in historical and projected data on risk that incorporates best available science (*e.g.*, the most recent National Climate Assessment).

Disaster recovery needs evolve over time and grantees must amend the impact and unmet needs assessment and action plan as additional needs are identified and additional resources become available. At a minimum, grantees must revisit and update the impact and unmet needs assessment when moving funds from one program to another through a substantial amendment.

III.C.1.b. *Connection of programs and projects to unmet needs.* The grantee must describe the connection between identified unmet needs and the allocation of CDBG–DR resources. The plan must provide a clear connection between a grantee's impact and unmet needs assessment and its proposed programs and projects in the MID areas (or outside in connection to the MID areas as described in section II.A.3). Such description must demonstrate a reasonably proportionate allocation of resources relative to areas and categories (*i.e.*, housing, economic revitalization, and infrastructure) of greatest needs identified in the grantee's impact and unmet needs assessment or provide an acceptable justification for a disproportional allocation, while also incorporating hazard mitigation measures to reduce the impacts of recurring natural disasters and the long-term impacts of climate change. Grantee action plans may provide for the allocation of funds for administration and planning activities and for public service activities, subject to the caps on such activities as described in the Consolidated Notice.

III.C.1.c. *Public housing, affordable rental housing, and housing for vulnerable populations.* Each grantee must include a description of how it has analyzed, identified, and will address (with CDBG–DR or other sources) the disaster-related rehabilitation, reconstruction, and new construction needs in the MID-area of the types of housing described below. Specifically, a grantee must assess and describe how it will address unmet needs in the following types of housing, subject to the applicable HUD program requirements: public housing, affordable rental housing (including both subsidized and market rate affordable housing), and housing for vulnerable populations (*See* section III.C.1.c.iii below), including emergency shelters and permanent housing for persons experiencing homelessness, in the areas affected by the disaster. Grantees must coordinate with local public housing authorities (PHA) in the MID areas to ensure that the grantee's representation in the action plan reflects the input of those entities as well as coordinating with State Housing Finance agencies to make sure that all funding sources that are available and opportunities for leverage are noted in the action plan.

(i) *Public housing:* Describe unmet public housing needs of each disaster-impacted PHA within its jurisdiction, if applicable. The grantee must work directly with impacted PHAs in identifying necessary and reasonable costs and ensuring that adequate funding from all available sources is dedicated to addressing the unmet needs of damaged public housing (*e.g.*, FEMA, insurance, and funds available from programs administered by HUD's Office of Public and Indian Housing).

(ii) *Affordable rental housing:* Describe unmet affordable rental housing needs for LMI households as a result of the disaster or exacerbated by the disaster, including private market units receiving project-based rental assistance or with tenants that participate in the section 8 Housing Choice Voucher Program, and any other housing that is

assisted under a HUD program in the MID areas. Identify funding to specifically address these unmet needs for affordable rental housing to LMI households. If a grantee is proposing an allocation of CDBG–DR funds for affordable rental housing needs, the action plan must, at a minimum, meet the requirements described in II.B.3.

(iii) Housing for vulnerable populations: Describe how CDBG–DR or other funding sources available will promote housing for vulnerable populations, as defined in section III.C.1.d., in the MID area, including how it plans to address: (1) transitional housing, including emergency shelters and housing for persons experiencing homelessness, permanent supportive housing, and permanent housing needs of individuals and families (including subpopulations) that are experiencing or at risk of experiencing homelessness; (2) the prevention of low-income individuals and families with children (especially those with incomes below thirty percent of the area median) from becoming homeless; (3) the special needs of persons who are not experiencing homelessness but require supportive housing (*i.e.*, elderly, frail elderly, persons with disabilities (mental, physical, developmental, etc.), victims of domestic violence, persons with alcohol or other substance-use disorder, persons with HIV/AIDS and their families, and public housing residents, as identified in 24 CFR 91.315(e)).

III.C.1.d. *Fair housing, civil rights data, and advancing equity.*

The grantee must use its CDBG–DR funds in a manner that complies with its fair housing and nondiscrimination obligations, including title VI of the Civil Rights Act of 1964, 42 U.S.C. 2000d *et seq.*, the Fair Housing Act, 42 U.S.C. 3601–19, section 504 of the Rehabilitation Act of 1973, 29 U.S.C. 794, the Americans with Disabilities Act of 1990, 42 U.S.C. 12131 *et seq.*, and section 109 of the HCDA, 42 U.S.C. 5309. To ensure that the activities performed in connection with the action plan will comply with these requirements, the grantee must provide an assessment of whether its planned use of CDBG–DR funds will have an unjustified discriminatory effect on or failure to benefit racial and ethnic minorities in proportion to their communities' needs, particularly in racially and ethnically concentrated areas of poverty, and how it will address the recovery needs of impacted individuals with disabilities.

Grantees should also consider the impact of their planned use of CDBG–DR funds on other protected class groups under fair housing and civil rights laws, vulnerable populations, and other historically underserved communities. For purposes of the Consolidated Notice, HUD defines vulnerable populations as a group or community whose circumstances present barriers to obtaining or understanding information or accessing resources. In the action plan, grantees should identify those populations (*i.e.*, which protected class, vulnerable population, and historically underserved groups were considered) and how those groups can be expected to benefit from the activities set forth in the plan consistent with the civil rights requirements set forth above.

To perform such an assessment, grantees must include data for the HUD-identified and grantee-identified MID areas that identifies the following information, as it is available:

- Racial and ethnic make-up of the population, including relevant sub-populations depending on activities and programs outlined in the plan (this would include renters and homeowners if eligibility is dependent on housing tenure) and the specific sub-geographies in the MID areas in which those programs and activities will be carried out;
- LEP populations, including number and percentage of each identified group;
- Number and percentage of persons with disabilities;
- Number and percentage of persons belonging to Federally protected classes under the Fair Housing Act (race, color, national origin, religion, sex—which includes sexual orientation and gender identity—familial status, and disability) and other vulnerable populations as determined by the grantee;
- Indigenous populations and tribal communities, including number and percentage of each identified group;
- Racially and ethnically concentrated areas and concentrated areas of poverty; and
- Historically distressed and underserved communities;

Grantees must explain how the use of funds will reduce barriers that individuals may face when enrolling in and accessing CDBG–DR assistance, for example, barriers imposed by a lack of outreach to their community or by the lack of information in non-English languages or accessible formats for individuals with different types of disabilities.

Grantees are strongly encouraged to include examples of how their proposed allocations, selection criteria, and other actions can be expected to advance equity for protected class groups. Grantees are strongly encouraged to explain and provide examples of how their actions can be expected to advance the following objectives:

- Equitably benefit protected class groups in the MID areas, including racial and ethnic minorities, and sub geographies in the MID areas in which residents belonging to such groups are concentrated;
- To the extent consistent with purposes and uses of CDBG–DR funds, overcome prior disinvestment in infrastructure and public services for protected class groups, and areas in which residents belonging to such groups are concentrated, when addressing unmet needs;
- Enhance for individuals with disabilities in the MID areas (a) the accessibility of disaster preparedness, resilience, or recovery services, including the accessibility of evacuation services and shelters; (b) the provision of critical disaster-related information in accessible formats; and/or (c) the availability of integrated, accessible housing and supportive services.

Grantees must identify the proximity of natural and environmental hazards (*e.g.*, industrial corridors, sewage treatment facilities, waterways, EPA superfund sites, brownfields, etc.) to affected populations in the MID area, including members of

protected classes, vulnerable populations, and underserved communities and explore how CDBG–DR activities may mitigate environmental concerns and increase resilience among these populations to protect against the effects of extreme weather events and other natural hazards.

Grantees must also describe how their use of CDBG–DR funds is consistent with their obligation to affirmatively further fair housing. HUD regulations at 24 CFR 5.151 provide that affirmatively furthering fair housing means taking meaningful actions, in addition to combating discrimination, that overcome patterns of segregation and foster inclusive communities free from barriers that restrict access to opportunity based on protected characteristics. Specifically, affirmatively furthering fair housing means taking meaningful actions that, taken together, address significant disparities in housing needs and in access to opportunity, replacing segregated living patterns with truly integrated and balanced living patterns, transforming racially or ethnically concentrated areas of poverty into areas of opportunity, and fostering and maintaining compliance with civil rights and fair housing laws.

State and local government grantees must submit a certification to AFFH in accordance with 24 CFR 5.150, *et seq.* CDBG–DR grantees must also comply with the recordkeeping requirements of 24 CFR 570.506 and 24 CFR 570.490(b), as amended by the Consolidated Notice.

III.C.1.e. *Infrastructure.* In its action plan, each grantee must include a description of how it plans to meet the requirements of the Consolidated Notice, including how it will: promote sound, sustainable long-term recovery planning as described in this section; adhere to the elevation requirements established in section II.C.2.; and coordinate with local and regional planning efforts as described in section III.B.2.i and III.D.1.a. All infrastructure investments must be designed and constructed to withstand chronic stresses and extreme events by identifying and implementing resilience performance metrics as described in section II.A.2.c.

If a grantee is allocating funds for infrastructure, its description must include:

- (1) How it will address the construction or rehabilitation of disaster-related systems (*e.g.*, storm water management systems) or other disaster-related community-based mitigation systems (*e.g.*, using FEMA's community lifelines). State grantees carrying out infrastructure activities must work with units of general local government and Indian tribes in the MID areas to identify the unmet needs and associated costs of needed disaster-related infrastructure improvements;
- (2) How mitigation measures and strategies to reduce natural hazard risks, including climate-related risks, will be integrated into rebuilding activities;
- (3) The extent to which CDBG–DR funded infrastructure activities will achieve objectives outlined in regionally or locally established plans and policies that are designed to reduce future risk to the jurisdiction;
- (4) How the grantee will evaluate the costs and benefits in selecting infrastructure projects to assist with CDBG–DR funds;

(5) How the grantee will align infrastructure investments with other planned federal, state, or local capital improvements and infrastructure development efforts, and will work to foster the potential for additional infrastructure funding from multiple sources, including state and local capital improvement projects in planning, and the potential for private investment;

(6) How the grantee will employ adaptable and reliable technologies to prevent premature obsolescence of infrastructure; and

(7) How the grantee will invest in restoration of infrastructure and related long-term recovery needs within historically underserved communities that lacked adequate investments in housing, transportation, water, and wastewater infrastructure prior to the disaster.

III.C.1.f. *Minimize Displacement.* A description of how the grantee plans to minimize displacement of persons or entities, and assist any persons or entities displaced, and ensure accessibility needs of displaced persons with disabilities. Specifically, grantees must detail how they will meet the Residential Anti-displacement and Relocation Assistance Plan (RARAP) requirements in section IV.F.7. Grantees must indicate to HUD whether they will be amending an existing RARAP or creating a new RARAP specific to CDBG-DR. Grantees must meet the requirements related to the RARAP prior to implementing any activity with CDBG-DR grant funds, such as buyouts and other disaster recovery activities. Grantees must seek to minimize displacement or adverse impacts from displacement, consistent with the requirements of Section IV.F of the Consolidated Notice, section 104(d) of the HCDA (42 U.S.C. 5304(d)) and implementing regulations at 24 CFR part 42, and 24 CFR 570.488 or 24 CFR 570.606, as applicable. Grantees must describe how they will plan and budget for relocation activities in the action plan.

III.C.1.g. *Allocation and award caps.* The grantee must provide a budget for the full amount of the allocation that is reasonably proportionate to its unmet needs (or provide an acceptable justification for disproportional allocation) and is consistent with the requirements to integrate hazard mitigation measures into all its programs and projects. The grantee shall provide a description of each disaster recovery program or activity to be funded, including the CDBG-DR eligible activities and national objectives associated with each program and the eligibility criteria for assistance. The grantee shall also describe the maximum amount of assistance (*i.e.*, award cap) available to a beneficiary under each of the grantee's disaster recovery programs. A grantee may find it necessary to provide exceptions on a case-by-case basis to the maximum amount of assistance and must describe the process it will use to make such exceptions in its action plan. At a minimum, each grantee must adopt policies and procedures that communicate how it will analyze the circumstances under which an exception is needed and how it will demonstrate that the amount of assistance is necessary and reasonable. Each grantee must

also indicate in its action plan that it will make exceptions to the maximum award amounts when necessary, to comply with federal accessibility standards or to reasonably accommodate a person with disabilities.

III.C.1.h. *Cost controls and warranties.* The grantee must provide a description of the standards to be established for construction contractors performing work in the jurisdiction and the mechanisms to be used by the grantee to assist beneficiaries in responding to contractor fraud, poor quality work, and associated issues. Grantees must require a warranty period post-construction with a formal notification to beneficiaries on a periodic basis (*e.g.*, 6 months and one month before expiration date of the warranty). Each grantee must also describe its controls for assuring that construction costs are reasonable and consistent with market costs at the time and place of construction.

III.C.1.i. *Resilience planning.* Resilience is defined as a community's ability to minimize damage and recover quickly from extreme events and changing conditions, including natural hazard risks. At a minimum, the grantee's action plan must contain a description of how the grantee will: (a) emphasize high quality design, durability, energy efficiency, sustainability, and mold resistance; (b) support adoption and enforcement of modern and/or resilient building codes that mitigate against natural hazard risks, including climate-related risks (*e.g.*, sea level rise, high winds, storm surge, flooding, volcanic eruption, and wildfire risk, where appropriate and as may be identified in the jurisdiction's rating and identified weaknesses (if any) in building code adoption using FEMA's Nationwide Building Code Adoption Tracking (BCAT) portal), and provide for accessible building codes and standards, as applicable; (c) establish and support recovery efforts by funding feasible, cost-effective measures that will make communities more resilient against a future disaster; (d) make land-use decisions that reflect responsible and safe standards to reduce future natural hazard risks, *e.g.*, by adopting or amending an open space management plan that reflects responsible floodplain and wetland management and takes into account continued sea level rise, if applicable, and (e) increase awareness of the hazards in their communities (including for members of protected classes, vulnerable populations, and underserved communities) through outreach to the MID areas.

While the purpose of CDBG-DR funds is to recover from a Presidentially declared disaster, integrating hazard mitigation and resilience planning with recovery efforts will promote a more resilient and sustainable long-term recovery. The action plan must include a description of how the grantee will promote sound, sustainable long-term recovery planning informed by a post-disaster evaluation of hazard risk, including climate-related natural hazards and the creation of resilience performance metrics as described in paragraph II.A.2.c. of the Consolidated Notice. This information should be based on the history of FEMA and other federally-funded disaster mitigation efforts and, as appropriate, take into account

projected increases in sea level, the frequency and intensity of extreme weather events, and worsening wildfires. Grantees must use the FEMA-approved Hazard Mitigation Plan (HMP), Community Wildfire Protection Plan (CWPP), or other resilience plans to inform the evaluation, and it should be referenced in the action plan.

III.C.2. *Additional action plan requirements for states.* For state grantees, the action plan must describe how the grantee will distribute grant funds, either through specific programs and projects the grantee will carry out directly (through employees, contractors, or through subrecipients), or through a method of distribution of funds to local governments and Indian tribes (as permitted by III.B.2.d.). The grantee shall describe how the method of distribution to local governments or Indian tribes, or programs/projects carried out directly, will result in long-term recovery from specific impacts of the disaster.

All states must include in their action plan the information outlined in (1) through (7) below (in addition to other information required by section III.C.). For states using a method of distribution, if some required information is unknown when the grantee is submitting its action plan to HUD (*e.g.*, the list of programs or activities required by III.C.1.g. or the projected use of CDBG-DR funds by responsible entity as required by subparagraph (5) below), the grantee must update the action plan through a substantial amendment once the information is known. If necessary to comply with a statutory requirement that a grantee shall submit a plan detailing the proposed use of all funds prior to HUD's obligation of grant funds, HUD may obligate only a portion of grant funds until the substantial amendment providing the required information is submitted and approved by HUD.

(1) How the impact and unmet needs assessment informs funding determinations, including the rationale behind the decision(s) to provide funds to most impacted and distressed areas.

(2) When funds are subgranted to local governments or Indian tribes (either as subrecipients or through a method of distribution), all criteria used to allocate and award the funds including the relative importance of each criterion (including any priorities). If the criteria are unknown when the grantee is submitting the initial action plan to HUD, the grantee must update the action plan through a substantial amendment once the information is known. The substantial amendment must be submitted and approved before distributing the funds to a local government or Indian tribe.

(3) How the distribution and selection criteria will address disaster-related unmet needs in a manner that does not have an unjustified discriminatory effect based on race or other protected class and ensure the participation of minority residents and those belonging to other protected class groups in the MID areas. Such description should include an assessment of who may be expected to benefit, the timing of who will be prioritized, and the amount or proportion of benefits expected to be received by different communities or groups (*e.g.*, the

proportion of benefits going to different locations within the MID or to homeowners versus renters).

(4) The threshold factors and recipient or beneficiary grant size limits that are to be applied.

(5) The projected uses for the CDBG–DR funds, by responsible entity, activity, and geographic area.

(6) For each proposed program and/or activity, its respective CDBG activity eligibility category (or categories), national objective(s), and what disaster-related impact is addressed, as described in section II.A.1.

(7) When applications are solicited for programs carried out directly, all criteria used to select applications for funding, including the relative importance of each criterion, and any eligibility requirements. If the criteria are unknown when the grantee is submitting the initial action plan to HUD, the grantee must update the action plan through a substantial amendment once the information is known. The substantial amendment must be submitted and approved before selecting applications.

III.C.3. Additional action plan requirements for local governments. For local governments grantees, the action plan shall describe specific programs and/or activities they will carry out. The action plan must also describe:

(1) How the impact and unmet needs assessment informs funding determinations, including the rationale behind the decision(s) to provide funds to most impacted and distressed areas.

(2) All criteria used to select applications (including any priorities), including the relative importance of each criterion, and any eligibility requirements. If the criteria are unknown when the grantee is submitting the initial action plan to HUD, the grantee must update the action plan through a substantial amendment once the information is known. The substantial amendment must be submitted and approved before selecting applications.

(3) How the distribution and selection criteria will address disaster-related unmet needs in a manner that does not have an unjustified discriminatory effect and ensures the participation of minority residents and those belonging to other protected class groups in the MID areas, including with regards to who may benefit, the timing of who will be prioritized, and the amount or proportion of benefits expected to be received by different communities or groups (e.g., the proportion of benefits going to different locations within the MID or to homeowners versus renters).

(4) The threshold factors and grant size limits that are to be applied.

(5) The projected uses for the CDBG–DR funds, by responsible entity, activity, and geographic area.

(6) For each proposed program and/or activity, its respective CDBG activity eligibility category (or categories), national objective(s), and what disaster-related impact is addressed, as described in section II.A.1. of the Consolidated Notice.

III.C.4. Waiver of 45-day review period for CDBG–DR action plans to 60 days. HUD may disapprove an action plan or substantial

action plan amendment if it is incomplete. HUD works with grantees to resolve or provide additional information during the review period to avoid the need to disapprove an action plan or substantial action plan amendments. There are several issues related to the action plan as submitted that can be fully resolved via further discussion and revision during an extended review period, rather than through HUD disapproval of the plan, which in turn would require grantees to take additional time to revise and resubmit their respective plan. Therefore, the Secretary has determined that good cause exists and waives 24 CFR 91.500(a) to extend HUD's action plan review period from 45 days to 60 days.

The action plan (including SF–424 and certifications) must be submitted to HUD for review and approval using DRGR. By submitting required standard forms (that must be submitted with the action plan), the grantee is providing assurances that it will comply with statutory requirements, including, but not limited to civil rights requirements. Applicants and recipients are required to submit assurances of compliance with federal civil rights requirements. A grantee will use DRGR's upload function to include the SF 424 (including SF 424B and SF 424D, as applicable) and certifications with its action plan. Grantees receiving an allocation are required to submit an action plan within 120 days of the applicability date of the Allocation Announcement Notice, unless the grantee has requested, and HUD has approved an extension of the submission deadline. HUD will then review each action plan within 60 days from the date of receipt.

During its review, HUD typically provides grantees with comments on the submitted plan to avoid the need to disapprove an action plan and offers a grantee the opportunity to make updates to the action plan during the first forty-five days of HUD's initial sixty-day review period. If a grantee wants to make updates to the action plan, HUD will reject the Public Action Plan in DRGR to return the plan to the grantee. Then, once the grantee resubmits the plan, HUD reviews the revised plan within the initial sixty-day period. HUD is establishing an alternative process that offers a grantee the option to voluntarily provide a revised action plan, updated to respond to HUD's comments, no later than day forty-five in HUD's sixty-day review. A grantee is not required to participate in the revisions of the action plan during this time, but with the understanding that an action plan may be determined to be substantially incomplete. The Secretary may disapprove an action plan as substantially incomplete if HUD determines that the action plan does not meet the requirements of the Consolidated Notice and the applicable Allocation Announcement Notice.

III.C.5. Obligation and expenditure of funds. Once HUD approves the action plan and approves certifications if required by appropriations acts, it will then sign a grant agreement obligating allocated funds to the grantee. The grantee will continue the action plan process in DRGR to draw funds (see section V.C.1.).

The grantee must meet the applicable environmental requirements before the use or

commitment of funds for each activity. After the Responsible Entity (1) completes environmental review(s) pursuant to 24 CFR part 58 and receives from HUD an approved Request for Release of Funds and certification (as applicable), or (2) adopts another Federal agency's environmental review, approval, or permit and receives from HUD (or the state) an approved Request for Release of Funds and certification (as applicable), the grantee may draw down funds from the line of credit for an activity. The disbursement of grant funds must begin no later than 180 calendar days after HUD executes a grant agreement with the grantee. Failure to draw funds within this timeframe may result in HUD's review of the grantee's certification of its financial controls, procurement processes, and capacity, and may result in the imposition of any corrective actions deemed appropriate by HUD pursuant to 24 CFR 570.495, 24 CFR 570.910, or 24 CFR 1003.701.

III.C.6. Amending the action plan. The grantee must amend its action plan to update its needs assessment, modify or create new activities, or reprogram funds, as necessary, in the DRGR system. Each amendment must be published on the grantee's official website and describe the changes within the context of the entire action plan. A grantee's current version of its entire action plan must be accessible for viewing as a single document at any given point in time, rather than require the public or HUD to view and cross-reference changes among multiple amendments. HUD's DRGR system will include the capabilities necessary for a grantee to sufficiently identify the changes for each amendment. When a grantee has finished amending the content in the Public Action Plan, the grantee will click "Submit Plan" in the DRGR system. The DRGR system will prompt the grantee to select the "Public Action Plan" and identify the amendment type (substantial or nonsubstantial). The grantee will complete this cover page to describe each amendment. At a minimum, the grantee must: (1) identify exactly what content is being added, deleted, or changed; (2) clearly illustrate where funds are coming from and where they are moving to; and (3) include a revised budget allocation table that reflects the entirety of all funds, as amended.

III.C.6.a. Substantial amendment. In its action plan, each grantee must specify criteria for determining what changes in the grantee's plan constitute a substantial amendment to the plan. At a minimum, the following modifications will constitute a substantial amendment: a change in program benefit or eligibility criteria; the addition or deletion of an activity; a proposed reduction in the overall benefit requirement, as outlined in III.F.2.; or the allocation or reallocation of a monetary threshold specified by the grantee in their action plan. For all substantial amendments, the grantee must follow the same procedures required for the preparation and submission of an action plan for disaster recovery, with the exception of the public hearing requirements described in section III.D.1.b. and the consultation requirements described in section III.D.1.a., which are not required for substantial amendments. A substantial action plan

amendment shall require a 30-day public comment period.

III.C.6.b *Nonsubstantial amendment.* The grantee must notify HUD, but is not required to seek public comment, when it makes any plan amendment that is not substantial. Although nonsubstantial amendments do not require HUD's approval to become effective, the DRGR system must approve the amendment to change the status of the Public Action Plan to "reviewed and approved." The DRGR system will automatically approve the amendment by the fifth day, if not completed by HUD sooner.

III.C.7. *Projection of expenditures and outcomes.* Each grantee must submit projected expenditures and outcomes with the action plan. The projections must be based on each quarter's expected performance—beginning with the first quarter funds are available to the grantee and continuing each quarter until all funds are expended. The grantee will use DRGR's upload feature to include projections and accomplishments for each program created.

III.D. Citizen Participation Requirements

III.D.1. *Citizen participation waiver and alternative requirement.* To permit a more streamlined process and ensure disaster recovery grants are awarded in a timely manner, provisions of 42 U.S.C. 5304(a)(2) and (3), 42 U.S.C. 12707, 24 CFR 570.486, 24 CFR 1003.604, 24 CFR 91.105(b) through (d), and 24 CFR 91.115(b) through (d), with respect to citizen participation requirements, are waived and replaced by the alternative requirements in this section. The streamlined requirements require the grantee to include public hearings on the proposed action plan and provide a reasonable opportunity (at least 30 days) for citizen comment.

The grantee must follow a detailed citizen participation plan that satisfies the requirements of 24 CFR 91.115 or 91.105 (except as provided for in notices providing waivers and alternative requirements). Each local government receiving assistance from a state grantee must follow a detailed citizen participation plan that satisfies the requirements of 24 CFR 570.486 (except as provided for in notices providing waivers and alternative requirements).

In addition to the requirements above, the streamlined citizen participation alternative requirements for CDBG-DR grants are as follows:

III.D.1.a. *Requirement for consultation during plan preparation.* All grantees must consult with states, Indian tribes, local governments, Federal partners, nongovernmental organizations, the private sector, and other stakeholders and affected parties in the surrounding geographic area, including organizations that advocate on behalf of members of protected classes, vulnerable populations, and underserved communities impacted by the disaster, to ensure consistency of the action plan with applicable regional redevelopment plans. A grantee must consult with other relevant government agencies, including state and local emergency management agencies that have primary responsibility for the administration of FEMA funds, if applicable.

III.D.1.b. *Publication of the action plan and opportunity for public comment.* Following

the creation of the action plan or substantial amendment in DRGR and before the grantee submits the action plan or substantial amendment to HUD, the grantee must publish the proposed plan or amendment for public comment. The manner of publication must include prominent posting on the grantee's official disaster recovery website and must afford citizens, affected local governments, and other interested parties a reasonable opportunity to review the plan or substantial amendment. Grantees shall consider if there are potential barriers that may limit or prohibit vulnerable populations or underserved communities and individuals affected by the disaster from providing public comment on the grantee's action plan or substantial amendment. If the grantee identifies barriers that may limit or prohibit equitable participation, the grantee must take reasonable measures to increase coordination, communication, affirmative marketing, targeted outreach, and engagement with underserved communities and individuals, including persons with disabilities and persons with LEP.

At a minimum, the topic of disaster recovery on the grantee's website must be navigable by all interested parties from the grantee homepage and must link to the disaster recovery website required by section III.D.1.e. The grantee's records must demonstrate that it has notified affected citizens through electronic mailings, press releases, statements by public officials, media advertisements, public service announcements, and/or contacts with neighborhood organizations.

Additionally, the CDBG-DR grantee must convene at least one public hearing on the proposed action plan after it has published on its website to solicit public comment and before submittal of the action plan to HUD. If the grantee holds more than one public hearing, it must hold each hearing in a different location within the MID area in locations that the grantee determines will promote geographic balance and maximum accessibility. The minimum number of public hearings a grantee must convene on the action plan to obtain interested parties' views and to respond to comments and questions shall be determined by the amount of the grantee's CDBG-DR allocation: (1) CDBG-DR grantees with allocations under \$500 million are required to hold at least one public hearing in a HUD-identified MID area; and (2) CDBG-DR grantees with allocations over \$500 million or more shall convene at least two public hearings in HUD-identified MID areas.

Grantees may convene public hearings virtually (alone, or in concert with an in-person hearing). All in-person hearings must be held in facilities that are physically accessible to persons with disabilities. HUD's implementing regulations for section 504 of the Rehabilitation Act (24 CFR part 8, subpart C) provide that where physical accessibility is not achievable, grantees must give priority to alternative methods of product or information delivery that offer programs and activities to qualified individuals with disabilities in the most integrated setting appropriate. When conducting a virtual hearing, the grantee must allow questions in

real time, with answers coming directly from the grantee representatives to all "attendees."

For both virtual and in person hearings, grantees must update their citizen participation plans to provide that hearings be held at times and locations convenient to potential and actual beneficiaries, with accommodation for persons with disabilities and appropriate auxiliary aids and services to ensure effective communication, and specify how they will meet these requirements. See 24 CFR 8.6 for HUD's regulations about effective communication. Grantees must also provide meaningful access for individuals with LEP at both in-person and virtual hearings. In their citizen participation plan, state and local government grantees shall identify how the needs of non-English speaking residents will be met in the case of virtual and in-person public hearings where a significant number of non-English speaking residents can be reasonably expected to participate. In addition, for both virtual or in-person hearings, the grantee shall provide reasonable notification and access for citizens in accordance with the grantee's certifications at III.F.7.g., timely responses to all citizen questions and issues, and public access to all questions and responses.

III.D.1.c. *Consideration of public comments.* The grantee must provide a reasonable time frame (no less than 30 days) and method(s) (including electronic submission) for receiving comments on the action plan or substantial amendment. The grantee must consider all oral and written comments on the action plan or any substantial amendment. Any updates or changes made to the action plan in response to public comments should be clearly identified in the action plan. A summary of comments on the plan or amendment, and the grantee's response to each, must be included (e.g., uploaded) in DRGR with the action plan or substantial amendment. Grantee responses shall address the substance of the comment rather than merely acknowledge that the comment was received.

III.D.1.d. *Availability and accessibility of documents.* The grantee must make the action plan, any substantial amendments, vital documents, and all performance reports available to the public on its website. See the following guidance for more information on vital documents: https://www.lep.gov/guidance/HUD_guidance_Jan07.pdf. In addition, the grantee must make these documents available in a form accessible to persons with disabilities and those with LEP. Grantees must take reasonable steps to ensure meaningful access to their programs and activities by LEP persons, including members of protected classes, vulnerable populations, and individuals from underserved communities. In their citizen participation plan, state and local government grantees shall describe their procedures for assessing their language needs and identify any need for translation of notices and other vital documents. At a minimum, the citizen participation plan shall require that the state or local government grantee take reasonable steps to provide language assistance to ensure meaningful access to participation by non-English-speaking residents of the grantee's jurisdiction.

III.D.1.e. *Public website.* The grantee must maintain a public website that permits individuals and entities awaiting assistance and the general public to see how all grant funds are used and administered. The website must include copies of all relevant procurement documents and, except as noted in the next paragraph, all grantee administrative contracts, details of ongoing procurement processes, and action plans and amendments. The public website must be accessible to persons with disabilities and individuals with LEP.

To meet this requirement, each grantee must make the following items available on its website: the action plan created using DRGR (including all amendments); each performance report (as created using the DRGR system); citizen participation plan; procurement policies and procedures; all contracts, as defined in 2 CFR 200.22, that will be paid with CDBG–DR funds (including, but not limited to, subrecipients' contracts); and a summary including the description and status of services or goods currently being procured by the grantee or the subrecipient (e.g., phase of the procurement, requirements for proposals, etc.). Contracts and procurement actions that do not exceed the micro-purchase threshold, as defined in 2 CFR 200.1, are not required to be posted to a grantee's website.

III.D.1.f. *Application status.* The grantee must provide multiple methods of communication, such as websites, toll-free numbers, TTY and relay services, email address, fax number, or other means to provide applicants for recovery assistance with timely information to determine the status of their application.

III.D.1.g. *Citizen complaints.* The grantee will provide a timely written response to every citizen complaint. The grantee response must be provided within fifteen working days of the receipt of the complaint, or the grantee must document why additional time for the response was required. Complaints regarding fraud, waste, or abuse of government funds should be forwarded to the HUD OIG Fraud Hotline (phone: 1-800-347-3735 or email: hotline@hudoig.gov).

III.D.1.h. *General requirements.* For plan publication, the comprehensive disaster recovery website and vital documents must ensure effective communication for individuals with disabilities, as required by 24 CFR 8.6 and the Americans with Disabilities Act, as applicable. In addition to ensuring the accessibility of the comprehensive disaster recovery website and vital documents, this obligation includes the requirement to provide auxiliary aids and services where necessary to ensure effective communication with individuals with disabilities, which may take the form of the furnishing of the above referenced materials in alternative formats (24 CFR 8.6(a)(1)). When required by III.D.1.d., grantees must take reasonable steps to ensure meaningful access for individuals with LEP.

III.E. Program Income

III.E.1. *Program income waiver and alternative requirement.* For state and unit of general local government grantees, HUD is waiving all applicable program income rules

at 42 U.S.C. 5304(j), 24 CFR 570.489(e), 24 CFR 570.500, and 24 CFR 570.504 and providing the alternative requirement described below. Program income earned by Indian tribes that receive an allocation from HUD will be governed by the regulations at 24 CFR 1003.503 until grant closeout and not by the waivers and alternative requirements in this Consolidated Notice. Program income earned by Indian tribes that are subrecipients of state grantees or local government grantees will be subject to the program income requirements for subrecipients of those grantees.

III.E.1.a. *Definition of program income.* "Program income" is defined as gross income generated from the use of CDBG–DR funds, except as provided in III.E.1.b., and received by a state, local government, Indian tribe receiving funds from a grantee, or their subrecipients. When income is generated by an activity that is only partially assisted with CDBG–DR funds, the income shall be prorated to reflect the percentage of CDBG–DR funds used (e.g., a single loan supported by CDBG–DR funds and other funds, or a single parcel of land purchased with CDBG–DR funds and other funds). If CDBG funds are used with CDBG–DR funds on an activity, any income earned on the CDBG portion would not be subject to the waiver and alternative requirement in the Consolidated Notice.

Program income includes, but is not limited to, the following:

- (i) Proceeds from the disposition by sale or long-term lease of real property purchased or improved with CDBG–DR funds.
- (ii) Proceeds from the disposition of equipment purchased with CDBG–DR funds.
- (iii) Gross income from the use or rental of real or personal property acquired by a state, local government, or subrecipient thereof with CDBG–DR funds, less costs incidental to generation of the income.
- (iv) Gross income from the use or rental of real property owned by a state, local government, or subrecipient thereof, that was constructed or improved with CDBG–DR funds, less costs incidental to generation of the income.
- (v) Payments of principal and interest on loans made using CDBG–DR funds.
- (vi) Proceeds from the sale of loans made with CDBG–DR funds.
- (vii) Proceeds from the sale of obligations secured by loans made with CDBG–DR funds.
- (viii) Interest earned on program income pending disposition of the income, including interest earned on funds held in a revolving fund account.
- (ix) Funds collected through special assessments made against nonresidential properties and properties owned and occupied by non-LMI households, where the special assessments are used to recover all or part of the CDBG–DR portion of a public improvement.
- (x) Gross income paid to a state, local government, or subrecipient thereof, from the ownership interest in a for-profit entity in which the income is in return for the provision of CDBG–DR assistance.

III.E.1.b. *Program income—does not include:*

- (i) The total amount of funds that is less than \$35,000 received in a single year and

retained by a state, local government, or a subrecipient thereof.

(ii) Amounts generated by activities eligible under section 105(a)(15) of the HCDA and carried out by an entity under the authority of section 105(a)(15) of the HCDA.

III.E.1.c. *Retention of program income.* State grantees may permit a local government that receives or will receive program income to retain the program income but are not required to do so.

III.E.1.d. *Program income—use, close out, and transfer.*

(i) Program income received (and retained, if applicable) before or after closeout of the grant that generated the program income, and used to continue disaster recovery activities, is treated as additional CDBG–DR funds subject to the requirements of the Consolidated Notice and must be used in accordance with the grantee's action plan for disaster recovery. To the maximum extent feasible, program income shall be used or distributed before additional withdrawals from the U.S. Treasury are made, except as provided in III.E.1.e. below.

(ii) In addition to the alternative requirements dealing with program income required above, the following rules apply:

(1) A state or local government grantee may transfer program income to its annual CDBG program before closeout of the grant that generated the program income. In addition, state grantees may transfer program income before closeout to any annual CDBG-funded activities carried out by a local government within the state.

(2) Program income received by a grantee, or received and retained by a subrecipient, after closeout of the grant that generated the program income, may also be transferred to a grantee's annual CDBG award.

(3) In all cases, any program income received that is not used to continue the disaster recovery activity will not be subject to the waivers and alternative requirements of the Consolidated Notice. Rather, those funds will be subject to the state or local government grantee's regular CDBG program rules. Any other transfer of program income not specifically addressed in the Consolidated Notice may be carried out if the grantee first seeks and then receives HUD's approval.

III.E.1.e. *Revolving funds.* State and local government grantees may establish revolving funds to carry out specific, identified activities. State grantees may also establish a revolving fund to distribute funds to local governments or tribes to carry out specific, identified activities. A revolving fund, for this purpose, is a separate fund (with a set of accounts that are independent of other program accounts) established to carry out specific activities. These activities must generate payments used to support similar activities going forward. These payments to the revolving fund are program income and must be substantially disbursed from the revolving fund before additional grant funds are drawn from the U.S. Treasury for payments that could be funded from the revolving fund. Such program income is not required to be disbursed for nonrevolving fund activities. A revolving fund established by a CDBG–DR grantee shall not be directly

funded or capitalized with CDBG–DR grant funds, pursuant to 24 CFR 570.489(f)(3).

III.F. Other General Waivers and Alternative Requirements

III.F.1. *Consolidated Plan waiver.* HUD is temporarily waiving the requirement for consistency with the consolidated plan (requirements at 42 U.S.C. 12706, 24 CFR 91.225(a)(5), and 24 CFR 91.325(a)(5)), because the effects of a major disaster alter a grantee's priorities for meeting housing, employment, and infrastructure needs. In conjunction, 42 U.S.C. 5304(e) is also waived, to the extent that it would require HUD to annually review grantee performance under the consistency criteria. These waivers apply only for 24 months after the applicability date of the grantee's applicable Allocation Announcement Notice. If the grantee is not scheduled to submit a new three-to five-year consolidated plan within the next two years, the grantee must update its existing three-to five-year consolidated plan to reflect disaster-related needs no later than 24 months after the applicability date of the grantee's applicable Allocation Announcement Notice.

III.F.2. *Overall benefit requirement.* The primary objective of the HCDA is the "development of viable urban communities, by providing decent housing and a suitable living environment and expanding economic opportunities, principally for persons of low and moderate income" (42 U.S.C. 5301(c)). Consistent with the HCDA, this notice requires grantees to comply with the overall benefit requirements in the HCDA and 24 CFR 570.484, 24 CFR 570.200(a)(3), and 24 CFR 1003.208, which require that 70 percent of funds be used for activities that benefit LMI persons. For purposes of a CDBG–DR grant, HUD is establishing an alternative requirement that the overall benefit test shall apply only to the grant of CDBG–DR funds described in the Allocation Announcement Notice and related program income.

A grantee may seek to reduce the overall benefit requirement below 70 percent of the total grant, but must submit a substantial amendment as provided in section III.C.6.a. in the Consolidated Notice, and provide a justification that, at a minimum: (a) identifies the planned activities that meet the needs of its LMI population; (b) describes proposed activities and programs that will be affected by the alternative requirement, including their proposed location(s) and role(s) in the grantee's long-term disaster recovery plan; (c) describes how the activities/programs identified in (b) prevent the grantee from meeting the 70 percent requirement; (d) demonstrates that LMI persons' disaster-related needs have been sufficiently met and that the needs of non-LMI persons or areas are disproportionately greater, and that the jurisdiction lacks other resources to serve non-LMI persons; and (e) demonstrates a compelling need for HUD to lower the percentage of the grant that must benefit low- and moderate-income persons.

III.F.3. *Use of the urgent need national objective.* Because HUD provides CDBG–DR funds only to grantees with documented disaster-related impacts and each grantee is limited to spending funds only for the benefit

of areas that received a Presidential disaster declaration, the Secretary finds good cause to waive the urgent need national objective criteria in section 104(b)(3) of the HCDA and to establish the following alternative requirement for any CDBG–DR grantee using the urgent need national objective for a period of 36 months after the applicability date of the grantee's Allocation Announcement Notice.

Pursuant to this alternative requirement, grantees that use the urgent need national objective must: (1) describe in the impact and unmet needs assessment why specific needs have a particular urgency, including how the existing conditions pose a serious and immediate threat to the health or welfare of the community; (2) identify each program or activity in the action plan that will use the urgent need national objective—either through its initial action plan submission or through a substantial amendment submitted by the grantee within 36 months of the applicability date of the grantee's Allocation Announcement Notice; and (3) document how each program and/or activity funded under the urgent need national objective in the action plan responds to the urgency, type, scale, and location of the disaster-related impact as described in the grantee's impact and unmet needs assessment.

The grantee's action plan must address all three criteria described above to use the alternative urgent need national objective for the program and/or activity. This alternative urgent need national objective is in effect for a period of 36 months following the applicability date of the grantee's Allocation Announcement Notice. After 36 months, the grantee will be required to follow the criteria established in section 104(b)(3) of the HCDA and its implementing regulations in 24 CFR part 570 when using the urgent need national objective for any new programs and/or activities added to an action plan.

III.F.4. *Reimbursement of disaster recovery expenses by a grantee or subrecipient.* The provisions of 24 CFR 570.489(b) are applied to permit a state grantee to charge to the grant otherwise allowable costs incurred by the grantee, its recipients or subrecipients (including Indian tribes and PHAs) on or after the incident date of the covered disaster. A local government grantee is subject to the provisions of 24 CFR 570.200(h) but may reimburse itself or its subrecipients for otherwise allowable costs incurred on or after the incident date of the covered disaster. Section 570.200(h)(1)(i) is waived to the extent that it requires pre-agreement activities to be included in the local government's consolidated plan. As an alternative requirement, grantees must include any pre-agreement activities in their action plans, including any costs of eligible activities that were funded with short-term loans (e.g., bridge loans) and that the grantee intends to reimburse or otherwise charge to the grant, consistent with applicable program requirements.

III.F.5. *Reimbursement of pre-application costs of homeowners, renters, businesses, and other qualifying entities.* Grantees are permitted to charge to grants the pre-award and pre-application costs of homeowners, renters, businesses, and other qualifying

entities for eligible costs these applicants have incurred in response to an eligible disaster covered under a grantees' applicable Allocation Announcement Notice. For purposes of the Consolidated Notice, pre-application costs are costs incurred by an applicant to CDBG–DR funded programs before the time of application to a grantee or subrecipient, which may be before (pre-award) or after the grantee signs its CDBG–DR grant agreement. In addition to the terms described in the remainder of the Consolidated Notice, grantees may only charge costs to the grant that meet the following requirements:

- Grantees may only charge the costs for rehabilitation, demolition, and reconstruction of single family, multifamily, and nonresidential buildings, including commercial properties, owned by private individuals and entities, incurred before the owner applies to a CDBG–DR grantee, recipient, or subrecipient for CDBG–DR assistance;
- For rehabilitation and reconstruction costs, grantees may only charge costs for activities completed within the same footprint of the damaged structure, sidewalk, driveway, parking lot, or other developed area;
- As required by 2 CFR 200.403(g), costs must be adequately documented; and
- Grantees must complete a duplication of benefits check before providing assistance pursuant to section IV.A. in the Consolidated Notice.

Grantees are required to ensure that all costs charged to a CDBG–DR grant are necessary expenses related to authorized recovery purposes. Grantees may charge to CDBG–DR grants the eligible pre-application costs of individuals and private entities related to single family, multifamily, and nonresidential buildings, only if: (1) the person or private entity incurred the expenses within one year after the applicability date of the grantee's Allocation Announcement Notice (or within one year after the date of the disaster, whichever is later); and (2) the person or entity pays for the cost before the date on which the person or entity applies for CDBG–DR assistance. Exempt activities as defined at 24 CFR 58.34, but not including 24 CFR 58.34(a)(12), and categorical exclusions as defined at 24 CFR 58.35(b) are not subject to the time limit on pre-application costs outlined above. Actions that convert or potentially convert to exempt under 24 CFR 58.34(a)(12) remain subject to the reimbursement requirements provided herein. If a grantee cannot meet all requirements at 24 CFR part 58, the pre-application costs cannot be reimbursed with CDBG–DR or other HUD funds.

Grantees must comply with the necessary and reasonable cost principles for state, local, and Indian tribal governments (described at 2 CFR 200.403). Grantees must incorporate into their policies and procedures the basis for determining that the assistance provided under the terms of this provision is necessary and reasonable.

A grantee may not charge such pre-award or pre-application costs to grants if the grantee cannot meet all requirements at 24 CFR part 58. Under CDBG–DR authorizing

legislation and HUD's environmental regulations in 24 CFR part 58, the CDBG-DR "recipient" (as defined in 24 CFR part 58.2(a)(5), which differs from the definition in 2 CFR part 200) is the responsible entity that assumes the responsibility for completing environmental reviews under Federal laws and authorities. The responsible entity assumes all legal liability for the application, compliance, and enforcement of these requirements. Pre-award costs are also allowable when CDBG-DR assistance is provided for the rehabilitation, demolition, or reconstruction of government buildings, public facilities, and infrastructure. However, in such instances, the environmental review must occur before the underlying activity (e.g., rehabilitation of a government building) begins.

Grantees are also required to consult with the State Historic Preservation Officer, Fish and Wildlife Service, and National Marine Fisheries Service, to obtain formal agreements for compliance with section 106 of the National Historic Preservation Act (54 U.S.C. 306108) and section 7 of the Endangered Species Act of 1973 (16 U.S.C. 1536) when designing a reimbursement program.

All grantees must follow all cross-cutting requirements, as applicable, for all CDBG-DR funded activities including but not limited to the environmental requirements above, the Davis Bacon Act, Civil Rights Requirements, HUD's Lead Safe Housing Rule, and the URA.

III.F.6. Alternative requirement for the elevation of structures when using CDBG-DR funds as the non-Federal match in a FEMA-funded project. Currently, CDBG-DR grantees using FEMA and CDBG-DR funds on the same activity have encountered challenges in certain circumstances in reconciling CDBG-DR elevation requirements and those established by FEMA. FEMA regulations at 44 CFR 9.11(d)(3)(i) and (ii) prohibit new construction or substantial improvements to a structure unless the lowest floor of the structure is at or above the level of the base flood and, for Critical Actions, at or above the level of the 500-year flood. However, 44 CFR 9.11(d)(3)(iii) allows for an alternative to elevation to the 100- or 500-year flood level, subject to FEMA approval, which would provide for improvements that would ensure the substantial impermeability of the structure below flood level. While FEMA may change its standards for elevation in the future, as long as the CDBG-DR grantee is following a FEMA-approved flood standard this waiver and alternative requirement will continue to apply.

FEMA funded projects generally commence well in advance of the availability of CDBG-DR funds and when CDBG-DR funds are used as match for a FEMA project that is underway, the alignment of HUD's elevation standards with any alternative standard allowed by FEMA may not be feasible and may not be cost reasonable. For these reasons, the Secretary finds good cause to establish an alternative requirement for the use of an alternative, FEMA-approved flood standard instead of the elevation requirements established in section II.B.2.c. and II.C.2. of the Consolidated Notice.

The alternative requirements apply when: (a) CDBG-DR funds are used as the non-

Federal match for FEMA assistance; (b) the FEMA-assisted activity, for which CDBG-DR funds will be used as match, commenced before HUD's obligation of CDBG-DR funds to the grantee; and (c) the grantee has determined and demonstrated with records in the activity file that implementation costs of the required CDBG-DR elevation or flood proofing requirements are not reasonable costs, as that term is defined in the applicable cost principles at 2 CFR 200.404.

III.F.7. Certifications waiver and alternative requirement. Sections 104(b)(4), (c), and (m) of the HCDA (42 U.S.C. 5304(b)(4), (c) & (m)), sections 106(d)(2)(C) & (D) of the HCDA (42 U.S.C. 5306(d)(2)(C) & (D)), and section 106 of the Cranston-Gonzalez National Affordable Housing Act (42 U.S.C. 12706), and regulations at 24 CFR 91.225 and 91.325 are waived and replaced with the following alternative. Each grantee receiving an allocation under an Allocation Announcement Notice must make the following certifications with its action plan:

a. The grantee certifies that it has in effect and is following a residential anti-displacement and relocation assistance plan (RARAP) in connection with any activity assisted with CDBG-DR grant funds that fulfills the requirements of section 104(d), 24 CFR part 42, and 24 CFR part 570, as amended by waivers and alternative requirements.

b. The grantee certifies its compliance with restrictions on lobbying required by 24 CFR part 87, together with disclosure forms, if required by part 87.

c. The grantee certifies that the action plan for disaster recovery is authorized under state and local law (as applicable) and that the grantee, and any entity or entities designated by the grantee, and any contractor, subrecipient, or designated public agency carrying out an activity with CDBG-DR funds, possess(es) the legal authority to carry out the program for which it is seeking funding, in accordance with applicable HUD regulations as modified by waivers and alternative requirements.

d. The grantee certifies that activities to be undertaken with CDBG-DR funds are consistent with its action plan.

e. The grantee certifies that it will comply with the acquisition and relocation requirements of the URA, as amended, and implementing regulations at 49 CFR part 24, as such requirements may be modified by waivers or alternative requirements.

f. The grantee certifies that it will comply with section 3 of the Housing and Urban Development Act of 1968 (12 U.S.C. 1701u) and implementing regulations at 24 CFR part 75.

g. The grantee certifies that it is following a detailed citizen participation plan that satisfies the requirements of 24 CFR 91.115 or 91.105 (except as provided in waivers and alternative requirements). Also, each local government receiving assistance from a state grantee must follow a detailed citizen participation plan that satisfies the requirements of 24 CFR 570.486 (except as provided for in waivers and alternative requirements).

h. State grantee certifies that it has consulted with all disaster-affected local

governments (including any CDBG-entitlement grantees), Indian tribes, and any local public housing authorities in determining the use of funds, including the method of distribution of funding, or activities carried out directly by the state.

i. The grantee certifies that it is complying with each of the following criteria:

(1) Funds will be used solely for necessary expenses related to disaster relief, long-term recovery, restoration of infrastructure and housing, economic revitalization, and mitigation in the most impacted and distressed areas for which the President declared a major disaster pursuant to the Robert T. Stafford Disaster Relief and Emergency Assistance Act of 1974 (42 U.S.C. 5121 *et seq.*).

(2) With respect to activities expected to be assisted with CDBG-DR funds, the action plan has been developed so as to give the maximum feasible priority to activities that will benefit low- and moderate-income families.

(3) The aggregate use of CDBG-DR funds shall principally benefit low- and moderate-income families in a manner that ensures that at least 70 percent (or another percentage permitted by HUD in a waiver) of the grant amount is expended for activities that benefit such persons.

(4) The grantee will not attempt to recover any capital costs of public improvements assisted with CDBG-DR grant funds, by assessing any amount against properties owned and occupied by persons of low- and moderate-income, including any fee charged or assessment made as a condition of obtaining access to such public improvements, unless: (a) disaster recovery grant funds are used to pay the proportion of such fee or assessment that relates to the capital costs of such public improvements that are financed from revenue sources other than under this title; or (b) for purposes of assessing any amount against properties owned and occupied by persons of moderate income, the grantee certifies to the Secretary that it lacks sufficient CDBG funds (in any form) to comply with the requirements of clause (a).

j. State and local government grantees certify that the grant will be conducted and administered in conformity with title VI of the Civil Rights Act of 1964 (42 U.S.C. 2000d), the Fair Housing Act (42 U.S.C. 3601-3619), and implementing regulations, and that it will affirmatively further fair housing. An Indian tribe grantee certifies that the grant will be conducted and administered in conformity with the Indian Civil Rights Act.

k. The grantee certifies that it has adopted and is enforcing the following policies, and, in addition, state grantees must certify that they will require local governments that receive their grant funds to certify that they have adopted and are enforcing:

(1) A policy prohibiting the use of excessive force by law enforcement agencies within its jurisdiction against any individuals engaged in nonviolent civil rights demonstrations; and

(2) A policy of enforcing applicable state and local laws against physically barring entrance to or exit from a facility or location

that is the subject of such nonviolent civil rights demonstrations within its jurisdiction.

l. The grantee certifies that it (and any subrecipient or administering entity) currently has or will develop and maintain the capacity to carry out disaster recovery activities in a timely manner and that the grantee has reviewed the requirements applicable to the use of grant funds.

m. The grantee certifies to the accuracy of its Financial Management and Grant Compliance Certification Requirements, or other recent certification submission, if approved by HUD, and related supporting documentation as provided in section III.A.1. of the Consolidated Notice and the grantee's implementation plan and related submissions to HUD as provided in section III.A.2. of the Consolidated Notice.

n. The grantee certifies that it will not use CDBG-DR funds for any activity in an area identified as flood prone for land use or hazard mitigation planning purposes by the state, local, or tribal government or delineated as a Special Flood Hazard Area (or 100-year floodplain) in FEMA's most current flood advisory maps, unless it also ensures that the action is designed or modified to minimize harm to or within the floodplain, in accordance with Executive Order 11988 and 24 CFR part 55. The relevant data source for this provision is the state, local, and tribal government land use regulations and hazard mitigation plans and the latest-issued FEMA data or guidance, which includes advisory data (such as Advisory Base Flood Elevations) or preliminary and final Flood Insurance Rate Maps.

o. The grantee certifies that its activities concerning lead-based paint will comply with the requirements of 24 CFR part 35, subparts A, B, J, K, and R.

p. The grantee certifies that it will comply with environmental requirements at 24 CFR part 58.

q. The grantee certifies that it will comply with the provisions of title I of the HCDA and with other applicable laws.

Warning: Any person who knowingly makes a false claim or statement to HUD may be subject to civil or criminal penalties under 18 U.S.C. 287, 1001, and 31 U.S.C. 3729.

III.G. Ineligible Activities in CDBG-DR

Any activity that is not authorized under section 105(a) of the HCDA is ineligible to be assisted with CDBG-DR funds, unless explicitly allowed by waiver and alternative requirement in the Consolidated Notice. Additionally, the uses described below are explicitly prohibited.

III.G.1. *Prohibition on compensation.* Grantees shall not use CDBG-DR funds to provide compensation to beneficiaries for losses stemming from disaster related impacts. Grantees may, however, reimburse disaster-impacted beneficiaries based on the pre-application costs incurred by the beneficiary to complete an eligible activity. Reimbursement of beneficiaries for eligible activity costs are subject to the requirements established in section III.F.5. of the Consolidated Notice.

III.G.2. *Prohibition on forced mortgage payoff.* A forced mortgage payoff occurs when homeowners with an outstanding

mortgage balance are required, under the terms of their loan agreement, to repay the balance of the mortgage loan before using assistance to rehabilitate or reconstruct their homes. CDBG-DR funds, however, shall not be used for a forced mortgage payoff. The ineligibility of a forced mortgage payoff with CDBG-DR funds does not affect HUD's longstanding guidance that when other non-CDBG disaster assistance is taken by lenders for a forced mortgage payoff, those funds are not considered to be available to the homeowner and do not constitute a duplication of benefits for the purpose of housing rehabilitation or reconstruction.

III.G.3. *Prohibiting assistance to private utilities.* HUD is adopting the following alternative requirement to section 105(a) and prohibiting the use of CDBG-DR funds to assist a privately-owned utility for any purpose.

IV. Other Program Requirements

IV.A. Duplication of Benefits

The grantee must comply with section 312 of the Stafford Act, as amended, which prohibits any person, business concern, or other entity from receiving financial assistance with respect to any part of a loss resulting from a major disaster for which such person, business concern, or other entity has received financial assistance under any other program or from insurance or any other source. To comply with section 312, a person or entity may receive financial assistance only to the extent that the person or entity has a disaster recovery need that has not been fully met. Grantees must also establish policies and procedures to provide for the repayment of a CDBG-DR award when assistance is subsequently provided for that same purpose from any other source. Grantees may be subject to additional DOB requirements described in a separate notice. The applicable Allocation Announcement Notice will describe any additional requirements, as applicable.

Subsidized loans are financial assistance and therefore can duplicate financial assistance provided from another source unless an exception in IV.A.1. applies.

IV.A.1. *Exceptions when subsidized loans are not a duplication.* When an exception described in paragraphs IV.A.1.a. or IV.A.1.b. applies, documentation required by those paragraphs must be maintained by the grantee. Without this documentation, any approved but undisbursed portion of a subsidized loan must be included in the grantee's calculation of the total assistance amount unless another exception applies. For cancelled SBA loans, the grantee must notify the SBA that the applicant has agreed to not take any actions to reinstate the cancelled loan or draw any additional undisbursed loan amounts.

IV.A.1.a. *Short-term subsidized loans for costs later reimbursed with CDBG-DR.* CDBG-DR funds may be used to reimburse pre-award costs of the grantee or subrecipient for eligible activities on or after the date of the disaster. If the grantee or subrecipient obtained a subsidized short-term loan to pay for eligible costs before CDBG-DR funds became available (for example, a low-interest loan from a local tax increment financing

fund), the reimbursement of the costs paid by the loan does not create a duplication.

IV.A.1.b. *Declined or cancelled subsidized loans.* The amount of a subsidized loan that is declined or cancelled is not a DOB. To exclude declined or cancelled loan amounts from the DOB calculation, the grantee must document that all or a portion of the subsidized loan is cancelled or declined.

(i) *Declined SBA Loans:* Declined loan amounts are loan amounts that were approved or offered by a lender in response to a loan application, but were turned down by the applicant, meaning the applicant never signed loan documents to receive the loan proceeds.

CDBG-DR grantees shall not treat declined subsidized loans, including declined SBA loans, as a DOB (but are not prohibited from considering declined subsidized loans for other reasons, such as underwriting). A grantee is only required to document declined loans if information available to the grantee (e.g., the data the grantee receives from FEMA, SBA, or other sources) indicates that the applicant received an offer for subsidized loan assistance, and the grantee is unable to determine from that available information that the applicant declined the loan. If the grantee is aware that the applicant received an offer of loan assistance and cannot ascertain from available data that the applicant declined the loan, the grantee must obtain a written certification from the applicant that the applicant did not accept the subsidized loan by signing loan documents and did not receive the loan.

(ii) *Cancelled Loans:* Cancelled loans are loans (or portions of loans) that were initially accepted, but for a variety of reasons, all or a portion of the loan amount was not disbursed and is no longer available to the applicant.

The cancelled loan amount is the amount that is no longer available. The loan cancellation may be due to default of the borrower, agreement by both parties to cancel the undisbursed portion of the loan, or expiration of the term for which the loan was available for disbursement. The following documentation is sufficient to demonstrate that any undisbursed portion of an accepted subsidized loan is cancelled and no longer available: (a) A written communication from the lender confirming that the loan has been cancelled and undisbursed amounts are no longer available to the applicant; or (b) a legally binding agreement between the CDBG-DR grantee (or local government, Indian tribe, or subrecipient administering the CDBG-DR assistance) and the applicant that indicates that the period of availability of the loan has passed and the applicant agrees not to take actions to reinstate the loan or draw any additional undisbursed loan amounts.

IV.B. Procurement

For a grantee to have proficient procurement processes, a grantee must: indicate the procurement standards that apply to its use of CDBG-DR funds; indicate the procurement standards for subrecipients or local governments as applicable; comply with the standards it certified to HUD that it follows (and update the certification

submissions when substantial changes are made); post the required documentation to the official website as described below; and include periods of performance and date of completion in all CDBG–DR contracts.

State grantees must comply with the procurement requirements at 24 CFR 570.489(g) and the following alternative requirements: The grantee must evaluate the cost or price of the product or service being procured. State grantees shall establish requirements for procurement processes for local governments and subrecipients based on full and open competition consistent with the requirements of 24 CFR 570.489(g), and shall require a local government or subrecipient to evaluate the cost or price of the product or service being procured with CDBG–DR funds. Additionally, if the state agency designated as the administering agency chooses to provide funding to another state agency, the administering agency must specify in its procurement processes whether the agency implementing the CDBG–DR activity must follow the procurement processes that the administering agency is subject to, or whether the agency must follow the same processes to which other local governments and subrecipients are subject, or its own procurement processes.

A grantee shall administer CDBG–DR grant funds in accordance with all applicable laws and regulations. As an alternative requirement, grantees may not delegate, by contract, or otherwise, the responsibility for administering such grant funds.

HUD is establishing an additional alternative requirement for all contracts with contractors used to provide goods and services, as follows:

1. The grantee (or procuring entity) is required to clearly state the period of performance or date of completion in all contracts;

2. The grantee (or procuring entity) must incorporate performance requirements and liquidated damages into each procured contract. Contracts that describe work performed by general management consulting services need not adhere to the requirement on liquidated damages but must incorporate performance requirements; and

3. The grantee (or procuring entity) may contract for administrative support, in compliance with 2 CFR 200.459, but may not delegate or contract to any other party any inherently governmental responsibilities related to oversight of the grant, including policy development, fair housing and civil rights compliance, and financial management.

IV.C. Use of the “Upper Quartile” or “Exception Criteria”

The LMA benefit requirement is modified when fewer than one quarter of the populated-block groups in its jurisdictions contain 51 percent or more LMI persons. In such a community, activities must serve an area that contains a percentage of LMI residents that is within the upper quartile of all census-block groups within its jurisdiction in terms of the degree of concentration of LMI residents. HUD determines the lowest proportion a grantee may use to qualify an area for this purpose

and advises the grantee, accordingly. The “exception criteria” applies to CDBG–DR funded activities in jurisdictions covered by such criteria, including jurisdictions that receive disaster recovery funds from a state. Disaster recovery grantees are required to use the most recent data available in implementing the exception criteria (<https://www.hudexchange.info/programs/acs-low-mod-summary-data/acs-low-mod-summary-data-exception-grantees/>).

IV.D. Environmental Requirements

IV.D.1. Clarifying note on the process for environmental release of funds when a state carries out activities directly. For CDBG–DR grants, HUD allows state grantees to carry out activities directly and to distribute funds to subrecipients. Per 24 CFR 58.4(b)(1), when a state carries out activities directly (including through subrecipients that are not units of general local government), the state must submit the Certification and Request for Release of Funds to HUD for approval.

IV.D.2. Adoption of another agency’s environmental review. Appropriations acts allow recipients of funds that use such funds to supplement Federal assistance provided under section 402, 403, 404, 406, 407, 408(c)(4), or 502 of the Stafford Act to adopt, without review or public comment, any environmental review, approval, or permit performed by a Federal agency. Such adoption shall satisfy the responsibilities of the recipient with respect to such environmental review, approval, or permit.

This provision allows the recipient of supplemental assistance to adopt another Federal agency’s review where the HUD assistance supplements the Stafford Act, and the other Federal agency performed an environmental review for assistance under section 402, 403, 404, 406, 407, or 502 of the Stafford Act.

The other agency’s environmental review must cover all project activities funded by the HUD recipient for each project. The grantee is only required to supplement the other agency’s environmental review to comply with HUD regulations (e.g., publication or posting requirements for Notice of Finding of No Significant Impact (FONSI), Notice of Intent to Request Release of Funds (NOI–RRF), concurrent or combined notices, or HUD approval period for objections) if the activity is modified so the other agency’s environmental review no longer covers the activity. The recipient’s environmental review obligations are considered complete when adopting another agency’s environmental review. To be adequate:

1. The grantee must obtain a completed electronic or paper copy of the Federal agency’s review and retain a copy in its environmental records.

2. The grantee must notify HUD on the Request for Release of Funds (RRF) Form 7015.15 (or the state, if the state is acting as HUD under 24 CFR 58.18) that another agency review is being used. The grantee must include the name of the other Federal agency, the name of the project, and the date of the project’s review as prepared by the other Federal agency.

When permitted by the applicable appropriations acts, and notwithstanding 42

U.S.C. 5304(g)(2), the Secretary or a state may, upon receipt of a Request for Release of Funds and Certification, immediately approve the release of funds for an activity or project assisted with CDBG–DR funds if the recipient has adopted an environmental review, approval, or permit under this section, or if the activity or project is categorically excluded from review under the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*) (NEPA).

IV.D.3. Historic preservation reviews. The responsible entity must comply with section 106 of the National Historic Preservation Act of 1966 (54 U.S.C. 306108). Early coordination under section 106 is important to the recovery process and required by 24 CFR 58.5(a).

IV.D.4. Tiered environmental reviews. Tiering, as described at 40 CFR 1508.1(ff) and 24 CFR 58.15, is a means of making the environmental review process more efficient by allowing parties to “eliminate repetitive discussions of the same issues, focus on the actual issues ripe for decision, and exclude from consideration issues already decided or not yet ripe at each level of environmental review” (40 CFR 1501.11(a)). Tiering is appropriate when a responsible entity is evaluating a single-family housing program with similar activities within a defined local geographic area and timeframe (e.g., rehabilitating single-family homes within a city district or county over the course of one to five years) but where the specific sites and activities are not yet known. Public notice and the Request for Release of Funds (HUD-Form 7015.15) are processed at a broad-level, eliminating the need for publication at the site-specific level. However, funds cannot be spent or committed on a specific site or activity until the site-specific review has been completed and approved.

IV.E. Flood Insurance Requirements

Grantees, recipients, and subrecipients must implement procedures and mechanisms to ensure that assisted property owners comply with all flood insurance requirements, including the purchase and notification requirements described below, before providing assistance.

IV.E.1. Flood insurance purchase requirements. When grantees use CDBG–DR funds to rehabilitate or reconstruct existing residential buildings in a Special Flood Hazard Area (or 100-year floodplain), the grantee must comply with applicable Federal, state, local, and tribal laws and regulations related to both flood insurance and floodplain management. The grantee must comply with section 102(a) of the Flood Disaster Protection Act of 1973 (42 U.S.C. 4012a) which mandates the purchase of flood insurance protection for any HUD-assisted property within a Special Flood Hazard Area. Therefore, a HUD-assisted homeowner for a property located in a Special Flood Hazard Area must obtain and maintain flood insurance in the amount and duration prescribed by FEMA’s National Flood Insurance Program.

IV.E.2. Federal assistance to owners remaining in a floodplain.

IV.E.2.a. Prohibition on flood disaster assistance for failure to obtain and maintain

flood insurance. Grantees must comply with section 582 of the National Flood Insurance Reform Act of 1994, as amended, (42 U.S.C. 5154a), which prohibits flood disaster assistance in certain circumstances. No Federal disaster relief assistance made available in a flood disaster area may be used to make a payment (including any loan assistance payment) to a person for “repair, replacement, or restoration” for damage to any personal, residential, or commercial property if that person at any time has received Federal flood disaster assistance that was conditioned on the person first having obtained flood insurance under applicable Federal law and the person has subsequently failed to obtain and maintain flood insurance as required under applicable Federal law on such property.

A grantee may not provide disaster assistance for the repair, replacement, or restoration of a property to a person who has failed to satisfy the Federal requirement to obtain and maintain flood insurance and must implement a process to verify and monitor for compliance with section 582 and the requirement to obtain and maintain flood insurance. Grantees are reminded that CDBG–DR funds may be used to assist beneficiaries in the purchase of flood insurance to comply with this requirement, subject to the requirements of cost reasonableness and other federal cost principles.

IV.E.2.b. Prohibition on flood disaster assistance for households above 120 percent of AMI for failure to obtain flood insurance. When a homeowner located in the floodplain allows their flood insurance policy to lapse, it is assumed that the homeowner is unable to afford insurance and/or is accepting responsibility for future flood damage to the home. Higher income homeowners who reside in a floodplain, but who failed to secure or decided to not maintain their flood insurance, should not be assisted at the expense of lower income households. To ensure that adequate recovery resources are available to assist lower income homeowners who reside in a floodplain but who are unlikely to be able to afford flood insurance, the Secretary finds good cause to establish an alternative requirement.

The alternative requirement to 42 U.S.C. 5305(a)(4) is as follows: Grantees receiving CDBG–DR funds are prohibited from providing CDBG–DR assistance for the rehabilitation/reconstruction of a house, if (i) the combined household income is greater than either 120 percent of AMI or the national median, (ii) the property was located in a floodplain at the time of the disaster, and (iii) the property owner did not obtain flood insurance on the damaged property, even when the property owner was not required to obtain and maintain such insurance.

IV.E.2.c. Responsibility to inform property owners to obtain and maintain flood insurance. Section 582 of the National Flood Insurance Reform Act of 1994, as amended, (42 U.S.C. 5154a) is a statutory requirement that property owners receiving disaster assistance that triggers the flood insurance purchase requirement have a statutory responsibility to notify any transferee of the requirement to obtain and maintain flood

insurance and to maintain such written notification in the documents evidencing the transfer of the property, and that the transferring owner may be liable if he or she fails to do so. A grantee or subrecipient receiving CDBG–DR funds must notify property owners of their responsibilities under section 582.

IV.F. URA, Section 104(d), and Related CDBG Program Requirements

Activities and projects undertaken with CDBG–DR funds may be subject to the URA, section 104(d) of the HCDA (42 U.S.C. 5304(d)), and CDBG program requirements related to displacement, relocation, acquisition, and replacement of housing, except as modified by waivers and alternative requirements provided in this notice. The implementing regulations for the URA are at 49 CFR part 24. The regulations implementing section 104(d) are at 24 CFR part 42. The regulations for applicable CDBG program requirements are at 24 CFR 570.488 and 24 CFR 570.606. HUD is waiving or providing alternative requirements in this section for the purpose of promoting the availability of decent, safe, and sanitary housing with respect to the use of CDBG–DR funds allocated under the Consolidated Notice.

IV.F.1. Section 104(d) one-for-one replacement of lower-income dwelling units. One-for-one replacement requirements at section 104(d)(2)(A)(i) and (ii) and 104(d)(3) of the HCDA and 24 CFR 42.375 are waived for owner-occupied lower-income dwelling units that are damaged by the disaster and not suitable for rehabilitation. The section 104(d) one-for-one replacement housing requirements apply to occupied and vacant occupiable lower-income dwelling units demolished or converted in connection with a CDBG assisted activity. This waiver exempts all disaster-damaged owner-occupied lower-income dwelling units that meet the grantee’s definition of “not suitable for rehabilitation,” from the one-for-one replacement housing requirements of 24 CFR 42.375. Before carrying out activities that may be subject to the one-for-one replacement housing requirements, the grantee must define “not suitable for rehabilitation” in its action plan or in policies/procedures governing these activities. Grantees are reminded that tenant-occupied and vacant occupiable lower-income dwelling units demolished or converted to another use other than lower-income housing in connection with a CDBG–DR assisted activity are generally subject to one-for-one replacement requirements at 24 CFR 42.375 and that these provisions are not waived.

HUD is waiving the section 104(d) one-for-one replacement requirement for owner-occupied lower-income dwelling units that are damaged by the disaster and not suitable for rehabilitation because the one-for-one replacement requirements do not account for the large, sudden changes that a major disaster may cause to the local housing stock, population, or economy. Disaster-damaged housing structures that are not suitable for rehabilitation can pose a threat to public health and safety and to economic

revitalization. Prior to the implementation of this waiver and alternative requirement, grantees must reassess post-disaster population and housing needs to determine the appropriate type and amount of lower-income dwelling units (both rental and owner-occupied units) to rehabilitate and/or reconstruct. Grantees should note that the demolition and/or disposition of public housing units continue to be subject to section 18 of the United States Housing Act of 1937, as amended, and 24 CFR part 970.

IV.F.2. Section 104(d) relocation assistance. The relocation assistance requirements at section 104(d)(2)(A)(iii) and (B) of the HCDA and 24 CFR 42.350, are waived to the extent that an eligible displaced person, as defined under 24 CFR 42.305 of the section 104(d) implementing regulations, may choose to receive either assistance under the URA and implementing regulations at 49 CFR part 24, or assistance under section 104(d) and implementing regulations at 24 CFR 42.350. This waiver does not impact a person’s eligibility as a displaced person under section 104(d), it merely limits the amounts and types of relocation assistance that a section 104(d) eligible displaced person is eligible to receive. A section 104(d) eligible displaced person is eligible to receive the amounts and types of assistance for displaced persons under the URA, as may be modified by the waivers and alternative requirements in this notice for activities related to disaster recovery. Without this waiver, disparities exist in relocation assistance associated with activities typically funded by HUD and FEMA (e.g., buyouts and relocation). Both FEMA and CDBG funds are subject to the requirements of the URA; however, CDBG funds are subject to section 104(d), while FEMA funds are not. This limited waiver of the section 104(d) relocation assistance requirements assures uniform and equitable treatment for individuals eligible to receive benefits under section 104(d) by establishing that all forms of relocation assistance to those individuals must be in the amounts and for the types of assistance provided to displaced persons under URA requirements.

IV.F.3. URA replacement housing payments for tenants. The requirements of sections 204 and 205 of the URA (42 U.S.C. 4624 and 42 U.S.C. 4625), and 49 CFR 24.2(a)(6)(vii), 24.2(a)(6)(ix), and 24.402(b) are waived to the extent necessary to permit a grantee to meet all or a portion of a grantee’s replacement housing payment obligation to a displaced tenant by offering rental housing through a rental housing program subsidy (to include, but not limited to, a housing choice voucher), provided that comparable replacement dwellings are made available to the tenant in accordance with 49 CFR 24.204(a) where the owner is willing to participate in the program and the period of authorized assistance is at least 42 months. This waiver and alternative requirement is subject to the following: if assistance is provided through a HUD program, it is subject to the applicable HUD program requirements, including the requirement that the tenant must be eligible for the rental housing program. Failure to grant this waiver would impede disaster recovery whenever

rental program subsidies are available but funds for cash replacement housing payments are limited and such payments are required by the URA to be based on a 42-month term.

IV.F.4. URA voluntary acquisition—homebuyer primary residence purchase. Grantees may implement disaster recovery program activities that provide financial assistance to eligible homebuyers to purchase and occupy residential properties as their primary residence. Such purchases are generally considered voluntary acquisitions under the URA and subject to the URA regulatory requirements at 49 CFR 24.101(b)(2). For CDBG–DR, 49 CFR 24.101(b)(2) is waived to the extent that it applies to a homebuyer, who does not have the power of eminent domain, and uses CDBG–DR funds in connection with the voluntary purchase and occupancy of a home the homebuyer intends to make their primary residence. This waiver is necessary to reduce burdensome administrative requirements for homebuyers following a disaster. Tenants displaced by these voluntary acquisitions may be eligible for relocation assistance.

IV.F.5. CDBG displacement, relocation, acquisition, and replacement housing program regulations—Optional relocation assistance. The regulations at 24 CFR 570.606(d) are waived to the extent that they require optional relocation policies to be established at the grantee level. Unlike with the regular CDBG program, states may carry out disaster recovery activities directly or through subrecipients, but 24 CFR 570.606(d) does not account for this distinction. This waiver makes clear that grantees receiving CDBG–DR funds may establish optional relocation policies or permit their subrecipients to establish separate optional relocation policies. The written policy must: be available to the public, describe the relocation assistance that the grantee, state recipient (*i.e.*, a local government receiving a subgrant from the state through a method of distribution), or subrecipient (as applicable) has elected to provide, and provide for equal relocation assistance within each class of displaced persons according to 24 CFR 570.606(d). This waiver is intended to provide states with maximum flexibility in developing optional relocation policies with CDBG–DR funds.

IV.F.6. Waiver of Section 414 of the Stafford Act. Section 414 of the Stafford Act (42 U.S.C. 5181) provides that “Notwithstanding any other provision of law, no person otherwise eligible for any kind of replacement housing payment under the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970 (Pub. L. 91–646) [42 U.S.C. 4601 *et seq.*] [“URA”] shall be denied such eligibility as a result of his being unable, because of a major disaster as determined by the President, to meet the occupancy requirements set by [the URA].” Accordingly, homeowner occupants and tenants displaced from their homes as a result of the identified disasters and who would have otherwise been displaced as a direct result of any acquisition, rehabilitation, or demolition of real property for a federally funded program or project may become eligible for a replacement housing

payment notwithstanding their inability to meet occupancy requirements prescribed in the URA. Section 414 of the Stafford Act and its implementing regulation at 49 CFR 24.403(d)(1) are waived to the extent that they would apply to real property acquisition, rehabilitation, or demolition of real property for a CDBG–DR funded project commencing more than one year after the date of the latest applicable Presidentially declared disaster undertaken by the grantees, or subrecipients, provided that the project was not planned, approved, or otherwise underway before the disaster.

For purposes of this waiver, a CDBG–DR funded project shall be determined to have commenced on the earliest of: (1) the date of an approved Request for Release of Funds and certification; (2) the date of completion of the site-specific review when a program utilizes Tiering; or (3) the date of sign-off by the approving official when a project converts to exempt under 24 CFR 58.34(a)(12).

The waiver will simplify the administration of the disaster recovery process and reduce the administrative burden associated with the implementation of Stafford Act section 414 requirements for projects commencing more than one year after the date of the Presidentially declared disaster considering most of such persons displaced by the disaster will have returned to their dwellings or found another place of permanent residence.

This waiver does not apply with respect to persons that meet the occupancy requirements to receive a replacement housing payment under the URA nor does it apply to persons displaced or relocated temporarily by other HUD-funded programs or projects. Such persons’ eligibility for relocation assistance and payments under the URA is not impacted by this waiver.

IV.F.7. RARAP Section 104(d). CDBG–DR grantees must certify that they have in effect and are following a RARAP as required by section 104(d)(1) and (2) of the HCDA and 24 CFR 42.325. In addition to the requirements in 24 CFR 42.325 and 24 CFR 570.488 or 24 CFR 570.606(c), as applicable, HUD is specifying the following alternative requirements:

Grantees who are following an existing RARAP for CDBG purposes must either: (1) amend their existing RARAP; or (2) create a separate RARAP for CDBG–DR purposes, to reflect the following requirements and applicable waivers and alternative requirements as modified by the Consolidated Notice.

Grantees who do not have an existing RARAP in place because they do not manage CDBG programs must create a separate RARAP for CDBG–DR purposes, to reflect the following CDBG–DR requirements and applicable waivers and alternative requirements as modified by the Consolidated Notice.

(1) RARAP requirements for CDBG–DR. As each grantee establishes and supports feasible and cost-effective recovery efforts to make communities more resilient against future disasters, the CDBG–DR RARAP must describe how the grantee plans to minimize displacement of members of families and

individuals from their homes and neighborhoods as a result of any CDBG–DR assisted activities, including disaster recovery activities where displacement can be prevented (*e.g.*, housing rehabilitation programs). Across disaster recovery activities—such as buyouts and other eligible acquisition activities, where minimizing displacement is not reasonable, feasible, or cost-efficient and would not help prevent future or repetitive loss—the grantee must describe how it plans to minimize the adverse impacts of displacement.

The description shall focus on proposed disaster recovery activities that may directly or indirectly result in displacement and the assistance that shall be required for those displaced. This description must focus on relocation assistance under the URA and its implementing regulations at 49 CFR part 24, section 104(d) and implementing regulations at 24 CFR part 42 (to the extent applicable), 24 CFR 570.488 and/or 24 CFR 570.606, and relocation assistance pursuant to this section of the Consolidated Notice, as well as any other assistance being made available to displaced persons. The CDBG–DR RARAP must include a description of how the grantee will plan programs or projects in such a manner that recognizes the substantial challenges experienced by displaced individuals, families, businesses, farms, and nonprofit organizations and develop solutions to minimize displacement or the adverse impacts of displacement especially among vulnerable populations. The description must be scoped to the complexity and nature of the anticipated displacing activities, including the evaluation of the grantee’s available resources to carry out timely and orderly relocations in compliance with all applicable relocation requirements.

V. Performance Reviews

Under 42 U.S.C. 5304(e) and 24 CFR 1003.506(a), the Secretary shall, at least on an annual basis, make such reviews and audits as may be necessary or appropriate to determine whether the grantee has carried out its activities in a timely manner (consistent process to meet its expenditure requirement), whether the grantee’s activities and certifications are carried out in accordance with the requirements and the primary objectives of the HCDA and other applicable laws, and whether the grantee has the continuing capacity to carry out those activities in a timely manner.

V.A. Timely Distribution and Expenditure of Funds

HUD waives the provisions at 24 CFR 570.494 and 24 CFR 570.902 regarding timely distribution and expenditure of funds, and establishes an alternative requirement providing that each grantee must expend 100 percent of its allocation within six years of the date HUD signs the grant agreement. HUD may extend the period of performance administratively, if good cause for such an extension exists at that time, as requested by the grantee, and approved by HUD. When the period of performance has ended, HUD will close out the grant and any remaining funds not expended by the grantee on appropriate programmatic purposes will be recaptured by HUD.

V.B. Review of Continuing Capacity

Upon a determination by HUD that the grantee has not carried out its CDBG–DR activities and certifications in accordance with the requirements in the Consolidated Notice, HUD will undertake a further review to determine if the grantee has the continuing capacity to carry out its activities in a timely manner. In making this determination, HUD will consider the nature and extent of the recipient's performance deficiencies, the actions taken by the recipient to address the deficiencies, and the success or likely success of such actions. HUD may then apply the following corrective and remedial actions as appropriate:

V.B.1. Corrective and remedial actions. To effectively administer the CDBG–DR program in a manner that facilitates recovery, particularly the alternative requirements permitting states to act directly to carry out eligible activities, HUD is waiving 42 U.S.C. 5304(e) to the extent necessary to establish the following alternative requirement: HUD may undertake corrective and remedial actions for states in accordance with the authorities for CDBG Entitlement grantees in subpart O (including corrective and remedial actions in 24 CFR 570.910, 570.911, and 570.913) or under subpart I of the CDBG regulations at 24 CFR part 570. In response to a deficiency, HUD may issue a warning letter followed by a corrective action plan that may include a management plan which assigns responsibility for further administration of the grant to specific entities or persons. Failure to comply with a corrective action may result in the termination, reduction, or limitation of payments to grantees receiving CDBG–DR funds.

V.B.2. Reduction, withdrawal, or adjustment of a grant, or other appropriate action. Before a reduction, withdrawal, or adjustment of a CDBG–DR grant, or other actions taken pursuant to this section, the recipient shall be notified of the proposed action and be given an opportunity for an informal consultation. Consistent with the procedures described in the Consolidated Notice, HUD may adjust, reduce, or withdraw the CDBG–DR grant (except funds that have been expended for eligible, approved

activities) or take other actions as appropriate.

V.B.3. Additional criteria and specific conditions to mitigate risk. To ensure effective grantee implementation of the financial controls, procurement processes, and other procedures that are the subject of the certification by the Secretary, HUD has and may continue to establish specific criteria and conditions for each grant award as provided for at 2 CFR 200.206 and 200.208, respectively, to mitigate the risk of the grant. The Secretary shall specify any such criteria and the resulting conditions in the grant conditions governing the award. These criteria may include, but need not be limited to, a consideration of the internal control framework established by the grantee to ensure compliant implementation of its financial controls, procurement processes and payment of funds to eligible entities, as well as the grantee's risk management strategy for information technology systems established to implement CDBG–DR funded programs. Additionally, the Secretary may amend the grant conditions to mitigate risk of a grant award at any point at which the Secretary determines a condition to be required to protect the Federal financial interest or to advance recovery.

V.C. Grantee Reporting Requirements in the DRGR System

V.C.1. DRGR-related waivers and alternative requirements. The Consolidated Notice waives the requirements for submission of a performance report pursuant to 42 U.S.C. 12708(a), 24 CFR 91.520, and annual status and evaluation reports that are due each fiscal year under 24 CFR 1003.506(a). Alternatively, HUD is requiring that grantees enter information in the DRGR system on a quarterly basis through the performance reports. The information in DRGR and the performance reports must contain sufficient detail to permit HUD's review of grantee performance and to enable remote review of grantee data to allow HUD to assess compliance and risk.

At a minimum, each grantee must:

a. Enter its action plan and amendments as described in III.C.1, including performance

measures, into the Public Action Plan in DRGR;

b. Enter activities into the DRGR Action Plan at a level of detail sufficient to allow HUD to determine grantee compliance (when the activity type, national objective, and the organization that will be responsible for the activity is known);

c. Categorize activities in DRGR under a "project";

d. Enter into the DRGR system summary information on grantees' monitoring visits and reports, audits, and technical assistance it conducts as part of its oversight of its disaster recovery programs;

e. Use the DRGR system to draw grant funds for each activity;

f. Use the DRGR system to track program income receipts, disbursements, revolving loan funds, and leveraged funds (if applicable);

g. Submit a performance report through the DRGR system no later than 30 days following the end of each calendar quarter. For all activities, the address of each CDBG–DR assisted property must be recorded in the performance report; and

h. Publish a version of the performance report that omits personally identifiable information reported in the performance reports submitted to HUD on the grantee's official website within three days of submission to HUD, or in the event a performance report is rejected by HUD, publish the revised version, as approved by HUD, within three days of HUD approval.

The grantee's first performance report is due after the first full quarter after HUD signs the grant agreement. Performance reports must be submitted on a quarterly basis until all funds have been expended and all expenditures and accomplishments have been reported. If a satisfactory report is not submitted in a timely manner, HUD may suspend access to CDBG–DR funds until a satisfactory report is submitted, or may withdraw and reallocate funding if HUD determines, after notice and opportunity for a hearing, that the jurisdiction did not submit a satisfactory report.

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